Assessment of Fuel Oil Availability

Final report

CE Delft
Committed to the Environment

STRATAS ADVISORS
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UMAS
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List of abbreviations an acronyms and glossary

2DO	#2 Diesel
2FO	Heating oil
AGO	Atmospheric gasoil, a CDU product
AGO HDS	Atmospheric gasoil hydro desulphurization
API	American Petroleum Institute
ATRES	Atmospheric residue, a CDU product
ATRES HDT	Atmospheric residue hydrotreating
BWMC	Ballast Water Management Convention
BWMS	Ballast Water Management System
CAGR	Compound Annual Growth Rate
CDU	Crude Distillation Unit
COKER/VBR HY DIST	Heavy distillate blend coming from hydrocrackers and visbreakers
CUTTER STOCK	Lighter product used to lower fuel oil viscosity (e.g. FCC heavy naphtha)
CNRB	Canadian Natural Resource Board
Delayed coker	Delayed coker, converts vacuum residue to naphtha, diesel, and coker gas oil via thermocracking
DME	Dimethyl Ether
EGCS	Exhaust Gas Cleaning System
EGR	Exhaust Gas Recirculation
EIA	US Energy Information Administration
EPA	US Environmental Protection Agency
FCC	Fluid Catalytic Cracking
FCC LCO	Fluidized Catalytic Cracker light cycle oil
GHG	Greenhouse Gas
GloTraM	Global Transport Model
GASOIL HDS	Gasoil hydrodesulphurization. Includes AGO and LCO desulphurization
GOHDS TOTAL	Gasoil hydrodesulphurization (FCC feed)
HC UCO	Hydrocracker unconverted oil
HFO	Heavy Fuel Oil
H-OIL®	Vacuum and Atmospheric Oil Catalytic hydrogenation. H-Oil® uses a catalytic hydrogenation technology in which considerable hydrocracking takes place. The process is used to upgrade atmospheric and vacuum residue to low sulphur distillates
H-OIL BTMS	Bottom product from H-Oil® Process (Vacuum residue hydrocracking)
H-OIL HY DIST	Heavy distillate coming from H-Oil® process
HOL	Residue Hydrocracking
HP	Hydrocarbon Processing
HSD	High sulphur diesel
Hydrocracker	Upgrades residues from the atmospheric or vacuum distillation columns (bottoms), FCC and coking units into jet fuel, diesel and gasoline via heavy molecules cracking in the presence of hydrogen and a catalyst
IAMs	Integrated Assessment Models
IEA	International Energy Agency
ISOMERIZATION	An Isomerization unit converts low octane n-paraffins (light naphtha from CDU) into high octane iso-paraffins via a chloride fixed bed reactor
IMO	International Maritime Organization

IMP CUTTER	Imported cutter stock
Kerosene	Kerosene, a CDU product
LCO	Light cycle oil, a FCC product used as a blending component in the heavy fuel oil pool
LCO HDS	Light cycle oil hydro desulphurization
LNG	Liquefied Natural Gas
LP	Linear Programming
LPG	Liquid Propane Gas
LSD	Low-sulphur diesel
MARPOL	International Convention for the Prevention of Pollution from Ships
Middle distillate hydroprocessing	Atmospheric gasoil hydro desulphurization.
MECL	Marine and Energy Consulting Limited
MGO	Marine Gas Oil
MMSCFD	Million Standard Cubic Feet per Day
NGL	Natural Gas Liquids
NPRA	National Petroleum Refiners Association
OGJ	Oil & Gas Journal
PADD	Petroleum Administration for Defense Districts
PAHs	Polyaromatic Hydrocarbons
REFORMER	A Reformer converts low octane linear paraffins into branched isoparaffins and cyclic naphthenes, which are then partially dehydrogenated to produce high-octane aromatic hydrocarbons in the presence of a catalyst
Residue hydroprocessing	Atmospheric residue hydrotreatment
RCPs	Representative Concentration Pathways
SCF	Standard Cubic Feet
SCFD	Standard Cubic Feet per Day
SDDG	Gasoil hydrotreatment
Slurry	Heaviest product from the FCC, also known as Decanted Oil (DO)
SR AGO	Straight run atmospheric gas oil
SR DIESEL	Straight run diesel, a CDU Product
SSP	Shared Socio-Economic Pathway
TR LT DIST	Treated light distillate
TRT AGO 85%	Treated atmospheric gasoil up to 85% desulphurization
TRT ATRES	Treated Atmospheric Residue
TRT KERO	Hydrotreated Kerosene
TRT KERO (DSL TR)	Hydrotreated Kerosene desulfurized Jet blend
TRT LCO	Treated light cycle oil
TRT LT DIST -MED HDS	Treated Light Distillate under medium-severity hydrodesulphurization conditions
TRT PURCH GASOIL	Imported/purchased hydrotreated gas oil
ULSD	Ultra low-sulphur diesel
UULSD	Ultra-Ultra-low-sulphur diesel
VCRES	Residue coming from the VDU
VDU	Vacuum Distillation Unit
Visbreaking	Reduction of the viscosity and pour point of VDU bottoms via thermal cracking of large hydrocarbon molecules in a furnace.
VISBR TAR	Visbreaker Tar

Content

1 Brief summary

MARPOL Annex VI requires all ships to use fuels with a sulphur content of 0.50% m/m from 1 January 2020 onwards (in Emission Control Areas, other limits apply). The implementation date is subject to a decision by the Parties to MARPOL Annex VI that these fuels are by then sufficiently available. In order to inform this decision, the IMO has commissioned the present study, which aims to assess the availability of fuel oil with a sulphur content of 0.50% m/m or less in 2020.

The study comprises three elements. First, the demand for marine fuels in 2020 has been estimated, based on the fuel consumption of ships in 2012, projected increases in energy demand, the use of alternative compliance options such as Exhaust Gas Cleaning Systems and the use of LNG.

The study has developed three scenarios, a base case with transport demand growth, fleet renewal, LNG and EGCS uptake in line with current projections; a high case with higher transport demand growth and fleet renewal and lower uptake of EGCSs and LNG, leading to greater demand for compliant petroleum fuels; and a low case which is the mirror image of the high case. Table 1 shows the fuel demand in each of these scenarios.

Table 1 **Fuel demand projections in the base case, high case and low case in 2020**

Sulphur (% m/m)	Petroleum derived fuels			LNG
	<0.10%	0.10%-0.50%	>0.50%	
	Million tonnes per year			
Base case	39	233	36	12
High case	48	290	14	12
Low case	33	198	38	13

Second, a refinery supply model has been developed and calibrated to global fuel production in 2012. This model has subsequently been updated to 2020 by taking into account all refinery expansions and closures that are expected to be completed by mid-2019 (see Table 2).

Table 2 **Global Refinery Capacity (2012 and mid-2019)**

	2012	2019	Change
	Million tonnes per year		
Crude Distillation	4,630	5,020	+8%
Light Oil Processing			
Reforming	610	626	+3%
Isomerization	94	122	+30%
Alkylation/polymerization	117	118	+1%
Conversion			
Coking	312	421	+35%
Catalytic cracking	862	916	+6%
Hydrocracking	388	532	+37%

	2012	2019	Change
	Million tonnes per year		
Hydroprocessing			
Gasoline	148	204	+38%
Naphtha	759	810	+7%
Middle distillates	1,109	1,306	+18%
Heavy oil/residual fuel	439	507	+15%

Third, the model has been used to assess whether the global refinery sector will be able to produce the marine fuels in sufficient quantities in 2020, while at the same time meeting demand from other sectors, and whether the production of these fuels is economically viable. These model runs were based on the projected crude slate for each region (which is different from the 2012 crude slate). The model was run conservatively, by e.g. limiting the capacity utilization of key units to 90% of stream day capacity and using conservative estimates of sulphur removal rates while setting sulphur contents of marine fuels that were 10% lower than the limit.

The main result of the assessment is that in all scenarios the refinery sector has the capability to supply sufficient quantities of marine fuels with a sulphur content of 0.50% m/m or less and with a sulphur content of 0.10% m/m or less to meet demand for these products, while also meeting demand for non-marine fuels (see Table 3).

Table 3 Global Refinery Production (2012 and 2020) - million tonnes per year

	Production in 2012	Production in 2020
Gasoline	963	1,086
Naphtha	256	305
Jet/Kero Fuel	324	331
Middle Distillate	1,316	1,521
MGO	64	39
Total Marine Heavy Fuel Oil (HFO)	228	269
Marine HFO (S $\leq$ 0.50% m/m)	0	233
Marine HFO (S > 0.50% m/m)	228	36
LPG	113	110
Other	784	537
Total	3,984	4,159

That future demand can be met is due to several developments. Capacity growth of crude distillation units enables production of larger quantities of fuel oil, while expansion of hydrocracking capacity increases the potential supply of unconverted gas oil, with a very low sulphur content which can be blended with heavy fuel oil to lower its sulphur content. Moreover, the increase in middle distillate and heavy fuel oil hydroprocessing helps meet the low sulphur requirements for marine distillates and heavy fuel oils, respectively.

In addition to these developments, the high demand case requires refineries in the Middle East and Asia to increase the utilization rates of their refining and processing units and to change their crude oil slate. For example, the average sulphur content of the crude slate in the Middle East will need to be lowered from 2.01% in the base case to 1.99% in the high demand case.

All compliant fuels (petroleum fuels with a sulphur content of 0.50% m/m or less) are blends of several refinery streams. Untreated atmospheric residue is typically only a fraction of the total blend. Most of these fuels have a considerably lower viscosity than HFO.

While supply and demand are balanced globally, regional surpluses and shortages are projected to occur. In most cases the Middle East has an oversupply, while in some cases other regions have a higher production than consumption as well. Regional imbalances can be addressed by transporting fuels or by changing vessels' bunkering patterns.

2 Introduction

2.1 Policy context

Since its adoption in 1997, MARPOL Annex VI has included a 4.50% m/m limit to the sulphur content of marine fuel. In October 2008, MEPC 58 agreed to reduce the maximum sulphur content to 3.5% m/m from 2012 and to 0.50% m/m from 2020 onwards (in emission control areas, stricter limits apply) by prohibiting the use of any fuel oil that exceeds this limit. These fuels may be petroleum fuels or other fuels with a sulphur content below the limit, such as LNG.

Apart from using compliant fuels, MARPOL Annex VI allows ships to comply by using alternative compliance options, as long as those options are at least as effective in terms of emission reductions as the sulphur content limits. In the case of sulphur, alternative compliance options comprise the use of exhaust gas cleaning systems that remove sulphur oxides from the exhaust (commonly called EGCSs).

MEPC 58 also agreed on a review provision. By 2018, a group of experts are to have conducted a review of the availability of fuel oil to comply with the standard, taking into account global market supply and demand for compliant fuel oil, an analysis of trends in fuel oil markets and any other relevant issue.

The Parties to MARPOL may then decide whether it is feasible for vessels to comply with the 2020 implementation date, based on the information developed by the group of experts.

2.2 Aim of this study

The overall objective of the present project is to conduct an assessment of the availability of fuel oil with a sulphur content of 0.50% m/m or less in 2020.

In order to meet the overall objective, there are three specific objectives:
1. Develop quantitative estimates of the demand for fuel oil meeting the global 0.50% m/m sulphur limit, both globally and for individual world regions, based on:
   a. The 2012 fuel volumes reported in the Third IMO GHG Study 2014.
   b. Appropriate growth factors to project fuel demand volumes for 2020.
   c. Variations in the input assumptions, representing the foreseeable high to low ranges of each assumption that will result in high to low ranges in demand.
2. Assess the ability of the refinery industry to supply the projected demand by:
   a. Building a base case for 2012.
   b. Modelling 2020 supply, taking into consideration fuel demand and specifications from other sectors.
3. Compare the demand and supply scenarios to assess their implications with respect to the availability of compliant fuels.

2.3 Scope of the analysis

The time horizon of the study is 2020. The study compares demand for and supply of compliant fuel oil in 2020. In order to account for uncertainty in projections and forecasts, we develop a range of estimates for both supply and demand, comparing these both globally and regionally to assess whether supply will be sufficient to meet demand.

In line with the definition in MARPOL Annex VI, regulation 2, 'fuel oil' means any fuel delivered to and intended for combustion purposes for propulsion or operation on board a ship, including gas, distillate and residual fuels (Resolution MEPC. 258(67) (MEPC, 2014).

Since Regulation 14 of MARPOL Annex VI sets limits for '[t]he sulphur content of any fuel oil used on board ships', the analysis includes demand from all ships, including ships on domestic voyages.

Although not all States are Party to MARPOL Annex VI and consequently are not bound by the sulphur limit imposed by Regulation 14, the analysis is aimed at all fuel used on board ships, regardless of where they sail.

In addition to MARPOL Annex VI, the EU and China, amongst others, have set regional limits on the sulphur content of marine fuels, some of which are currently in place and some of which will be implemented at a later stage. To the extent that they are implemented by 2020, these limits are taken into account in the analysis.

2.4 Outline of the report

This report is structured as follows:
- Chapter 3 presents an overview of the maritime fuels market in 2012, the latest year for which comprehensive data on both supply and demand are available. The chapter also reviews global refinery production as a context for the information presented on the maritime fuels market.
- Chapter 4 develops the projections of maritime fuel demand by 2020. It presents a projection of the energy demand by maritime transport and a projection of the use of EGCSs. It also includes a projection for non-maritime fuel demand by 2020.
- Chapter 5 focuses on the projection of refinery capacity and fuel supply by 2020. It analyses whether and, if so, how refineries can meet demand for compliant fuels in different scenarios.
- Chapter 6 presents the assessment of fuel availability in 2020.
- Chapter 7 contains the main conclusions.

The main report is complemented by a series of Annexes providing more background on the calculations underpinning the estimate of 2012 fuel demand; the refinery model used to calculate supply; the model for estimating the use of EGCSs; the projections of energy use by ships in 2020; and the projections of alternative fuel demand by 2020, respectively.

3 Supply and demand of maritime fuels in 2012

3.1 Introduction to 2012 supply and demand

This chapter presents quantitative data on the supply and demand of maritime fuels in 2012, both globally and regionally. These data serve as the starting point for the demand projections for 2020 in Chapter 4. In combination with the supply of non-maritime fuels, the supply figures serve to calibrate the refinery model employed to project 2020 production in Chapter 5.

The size of the maritime fuels market (both supply and demand) is presented in Section 3.2. Section 3.4 analyses how fuel sales (fuel demand) are distributed over world regions, while Section 3.5 assesses the refining capacity in the same regions. Section 3.6 concludes this chapter.

3.2 Size of the maritime fuels market in 2012

The estimation of global demand for maritime fuels in 2012 is based on the bottom-up approach used in the Third IMO GHG Study 2014. In that year total global consumption of maritime fuels was estimated to be 300 million tonnes. Using the data from the Third IMO GHG Study 2014, total global fuel consumption can be broken down by fuel type (HFO, MGO, LNG) and machinery component. The resultant values are reported in Table 4.

Table 4 Global shipping fuel consumption in 2012 by fuel type and machinery component based on the Third IMO GHG Study 2014 (million metric tonnes)

	HFO	MGO(1)	LNG(2)
Main engine	188	18	7
Auxiliary	33	42	1
Boiler	7	5	0
TOTAL	228	64	8

Source: This study, based on Third IMO GHG Study 2014.

(1) The reported MGO total is lower than the sum of consumption per machinery component owing to rounding.

(2) LNG was used both by gas carriers as a boil-off and to a lesser extent by LNG-fuelled ships.

This study performed a further quality assurance of the Third IMO GHG Study 2014's 2012 global demand for maritime fuels, which can be found in Annex A. The confidence interval of the 2012 fuel consumption data is between -17% and +5% of the values shown in Table 4.

3.3 Global supply of maritime fuels in 2012

Petroleum fuels for ships are supplied by refineries. Typically, various products are blended to achieve a product meeting specifications for sulphur content, viscosity, specific gravity, et cetera. Table 5 summarizes the global supply of refinery fuels in 2012, based on calibration model results.

Table 5 Global Refinery Production (2012) - million tonnes per year

Refinery Production(5)		
		Sulphur (% m/m)
Gasoline	963	
Naphtha	256	
Jet/Kerosene Fuel	324	
Middle Distillate Oil	1,316	
of which MGO(1,4)	64	0.14(3)
Marine Heavy Fuel Oil (HFO)	228	2.51(3)
LPG	113	
Other(2)	784	
Total	3,984	

Source: Stratas Advisors, 2015-2016.

(1) Global marine fuel demand. Source: (IMO, 2014).

(2) Includes petroleum coke, refinery fuel, non-marine fuel oil and other products.

(3) MEPC 65/4/19. Production volume and quality (% m/m sulphur) is the model output.

(4) MGO is part of Middle Distillate.

(5) Biofuel is included in the gasoline and middle distillate quantity.

In order to supply the products shown in Table 5, the supply model calculates average regional utilization rates[1]. Table 6 shows that the CDU utilization rates vary from 56% in Africa to 85% in Russia and CIS. CDU utilization reasonably matches available historical data, given that the reported rates for 2012 are based on 92% of stream day capacity and crude throughput (Africa 67%, Asia 85%, Europe 80%, North America 86%, Latin America 79%, Middle East 79%, Russia & CIS 85%. The utilization rates are plausible and indicate that the refinery model was appropriately calibrated.

1 Utilization rate is the percentage ratio of the total amount of liquids run through a process unit to the capacity of the unit. It is based on nameplate capacity, considering 8,000 hours of continuous operation, which is about 8.6% lower than stream day capacity (based on 8,760 hours of annual operation). For CDU, the utilization rate is the ratio of the total amount of crude run through crude distillation unit to the capacity of the CDU.

Table 6 **Regional Refinery Utilization rates for major units (2012)[1,2]**

Process[3]	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
CDU	56%	76%	76%	64%	72%	77%	85%
Hydrocracker	92%	69%	92%	77%	89%	92%	92%
Gohds total	0%	91%	57%	84%	33%	92%	92%
Atres hdt	0%	23%	46%	2%	0%	92%	0%
H-oil	92%	92%	52%	36%	0%	92%	84%
Gasoil HDS	92%	92%	92%	10%	0%	0%	0%
Ago HDS	92%	92%	92%	6%	0%	0%	0%
Lco HDS	0%	0%	0%	5%	0%	0%	0%
Delayed coker	0%	75%	87%	88%	81%	92%	71%
FCC	92%	69%	81%	80%	63%	92%	92%
Reformer	66%	70%	92%	83%	83%	70%	61%
Isomerisation	92%	92%	92%	64%	4%	92%	92%

Source: Stratas Advisors, 2015-2016.

(1) The numerical values are reported as percentages.

(2) Utilization rates are calculated based on 92% of stream day capacity (92% of stream day capacity is about 8,000 hrs of continuous operation out of 8,760 hrs maximum a year).

(3) Processes are described in the Glossary.

In 2012 global HFO and MGO demand accounted for 46% and 5%, respectively, of global fuel oil and middle distillate supply (Table **7**).

Table 7 **Global Marine Fuel sales as a percentage of refinery production (2012)**

Marine Fuel share of global supply	
Marine HFO share (%)	46
MGO share (%)	5

Source: Stratas Advisors.

3.4 Regional demand for maritime fuels in 2012

The data on regional demand for maritime fuels in 2012 adopted in this study are provided in Table 8. The first set of columns reports absolute regional demand, the second the relative regional share for each fuel type.

Table 8 Regional demand for maritime fuels and relative shares in 2012 (million tonnes per year)

	HFO	MGO	LNG	HFO	MGO	LNG
	Million tonnes			Regional share (%)		
Africa	7	3	0.51	3	5	7
Asia	95	31	1.92	42	48	24
Europe	52	15	0.64	23	23	8
North America	21	7	2.04	9	11	26
Latin America	18	6	0.17	8	9	2
Middle East	25	1	1.29	11	2	16
Russia & CIS	10	2	1.34	4	3	17
TOTALS	228	64	8	100%	100%	100%

Source: This report.

Note: Because of rounding values may not add to totals.

The approach used to derive disaggregated regional demands was as follows:
- disaggregate global fuel demand based on the IEA shares of regional fuel sales;
- verify regional fuel demand data against third-party data sources, adjusting as required;
- specifically for LNG a slightly different approach was adopted, using spatially explicit data from the bottom-up method of the Third GHG IMO Study and IEA statistics on natural gas.

Further details can be found in Annex A, Section A.3.

3.5 Regional supply of maritime fuels in 2012

Asia is the world's largest petroleum product producer. In 2012, Asia's total refinery production reached 1,266 million tonnes per year, accounting for 32% of global total refinery production (Table 9). Asia's marine heavy fuel oil and MGO made up 42 and 48% of global production, respectively.

Marine fuels accounted for 7.3% of the refinery production by mass in 2012 (Table 9).

Table 9 **Regional Refinery Production (2012) - million tonnes per year**

	Refinery Production(1)							
	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS	Global
Gasoline(2)	17	234	135	399	78	50	51	963
Naphtha	12	130	38	12	11	33	20	256
Jet Fuel	7	81	37	72	16	23	14	250
Kerosene	2	38	12	1	1	19	1	74
Middle Distillate Oil	34	453	280	257	105	98	89	1,316
MGO	3	31	15	7	6	1	2	64
Marine HFO	7	95	52	21	18	25	10	228
LPG	2	41	17	21	8	5	18	112
Other(3)	28	194	121	141	103	89	108	784
Total	109	1,266	692	924	340	342	311	3,984
Non-Marine Total	99	1,140	625	896	316	316	299	3,692

Source: Stratas Advisors, 2015-2016, CE Delft.

(1) Because of rounding values may not add to totals.

(2) Gasoline and Diesel both include biofuel blended volume.

(3) Includes lubricants, asphalt, refinery fuel gas, non-marine fuel oil, coke and miscellaneous products.

3.6 Conclusions on 2012 supply and demand

In 2012, the global consumption of HFO and MGO by ships amounted to 228 and 64 million metric tonnes, respectively, representing 46% and 5%, respectively, of global fuel oil and middle distillate supply. In addition, ships used 8 million metric tonnes of LNG, mainly in gas carriers.

In addition to marine refinery fuel production, non-marine refinery fuel production amounted to 3,692 million tonnes in 2012. Average regional refinery utilization rates varied considerably between regions. The highest rates were typically in Russia & CIS, the lowest in Africa.

4 Projections of fuel demand in 2020

4.1 Introduction to 2020 demand analysis

This chapter develops the projections of fuel demand by 2020 that have been used to run the refinery models. Global demand is disaggregated by fuel type and by region.

The projections are developed in four steps:
1. Project the energy demand of maritime transport using the projections of the Third IMO GHG Study 2014 as a basis, taking into account the possible impacts of the short-term business cycle (Section 4.2).
2. Project investments in exhaust gas cleaning systems (EGCSs), which can remove SO_x from the exhaust, enabling ships to use fuels with a sulphur content over 0.50% m/m (Section 4.3).
3. Project demand for non-petroleum fuels with a sulphur content of 0.50% m/m or less (Section 4.4).
4. Calculate global and regional demand for marine fuels, taking into account the amount of fuel consumed by ships with an EGCS, the amount of non-petroleum fuels used, and demand for 0.10% S and 0.50% S fuels (Section 4.5)

To enable modelling of supply from refineries, which encompasses all petroleum fuels, Section 4.6 projects the demand for non-marine fuels. Section 4.7 presents the estimates of total fuel demand by 2020.

Three projections of marine fuel demand are developed; a base case, a high demand case which reflects a high but still plausible demand for marine fuels with a sulphur content of 0.50% m/m or less, and a low demand case reflecting a scenario in which demand for such fuels is low. The main input assumptions are summarized in Table 10, with further details provided in Section 4.2. In all scenarios it has been assumed that there are no additional regulatory driven fuel efficiency improvements.

All cases take into account that, independent of the decision of MEPC, from 2019 ships sailing in areas near the Pearl River Delta, Yangtze River Delta and the Bohai Sea will be obliged to use fuel with a sulphur content of 0.50% or less, as well as in Hong Kong, China (L.N. 51/2015). Similarly, ships sailing in territorial seas, exclusive economic zones and pollution control zones of EU Member States, other than in ECAs, will be obliged to use fuel with a sulphur content of 0.50% or less as per Directive 2012/33/EC. Finally, ships sailing in North American, U.S. Caribbean and European ECAs will continue to be obliged to use fuel with a sulphur content of 0.10% m/m or less or an alternative compliance option.

These regional regulations affect demand for fuel with a sulphur content of 0.50% or less in a scenario where the IMO decides to defer the implementation of Regulation 14 until after 2020. If the implementation date remains unchanged, ships sailing in the aforementioned areas will be required to use fuel with a sulphur content of 0.50% or less anyway, and total demand for fuel of this quality will not be affected.

Table 10 **Input assumptions for fuel demand projections**

	Base case	High demand case	Low demand case
Socio-economic scenarios	RCP 6.0/SSP 1	RCP 8.5/SSP 5	RCP 4.5/SSP 3
Uptake of EGCS	Central-range stakeholder consultation	Lower than base case	Higher than base case
Uptake of alternative fuels	Central range	Lower than base case	Higher than base case
Additional market-driven fuel efficiency improvements	Central Marginal Abatement Cost Curve (MACC) results	Low-range MACC results	High-range MACC results

Source: CE Delft.

The projections distinguish the following fuel types:

a Petroleum fuels with a sulphur content of 0.10% m/m or less.
b Petroleum fuels with a sulphur content of more than 0.10% m/m but equal to or less than 0.50% m/m.
c Petroleum fuels with a sulphur content of more than 0.50% m/m.
d LNG.
e Methanol.
f Biofuels.
g LPG.
h DME.

Fuel types a, d, e, f, g, and h can be used in emission control areas, as well as b and c provided that the SO_x emissions are reduced to a level at least equivalent to using petroleum fuels with a sulphur content of 0.10% m/m. After 1 January 2020 (or 2025 if so decided by IMO), fuel type c can only be used in combination with an EGCS that reduces SO_x emissions to a level at least equivalent to using petroleum fuels with a sulphur content of 0.50% m/m outside ECAs and 0.10% m/m in ECAs (as of 1 January 2015).

4.2 Projections of global maritime energy demand

Global maritime energy demand has been estimated using the emissions projection model employed in the Third IMO GHG Study 2014. The model has been rerun to take into account recent developments in economic activity, fuel prices and fleet composition.

This section first presents the model and the inputs used. It then goes on to present the results of the energy demand projections.

4.2.1 Energy demand projection model

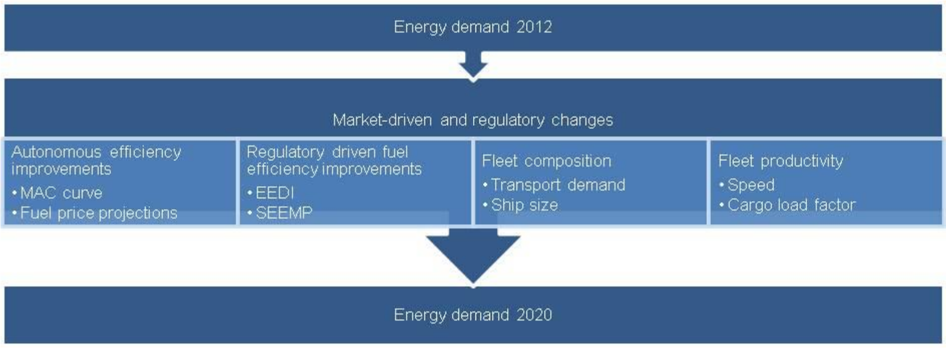
The energy demand projection model projects the energy demand of maritime transport in a future year based on energy demand in a base year and developments in relevant factors between the base year and the projection year. Because the Third IMO GHG Study 2014 has detailed data on energy demand in 2012, this has been chosen as the base year.
The model takes into account the following factors:

– Market-driven vessel efficiency developments. The model employs a MACC model in which all major options for efficiency improvements are included. It calculates the cost-effective emission reduction potential at a given fuel price and assumes that a certain fraction of cost-effective measures are

implemented. The SEEMP is assumed to draw attention to cost-effective measures.
- Regulatory efficiency improvements. The EEDI requires new ships for which the building contract is placed in or after 2013 to meet or exceed an increasingly stringent energy efficiency standard. The model assumes that ships will meet these EEDI requirements. In addition, ships sailing to and from EU ports will have to monitor and report their fuel use, emissions and several efficiency parameters. The efficiency improvements stemming from these operational efficiency measures are expected to total 2% on relevant voyages.
- Fleet composition, which may change in response to developments in transport demand. Transport demand has been projected based on socio-economic trends, using the method employed in the Third IMO GHG Study 2014 (IMO, 2014). Besides transport demand, developments in vessel size also affect fleet composition.
- Fleet productivity, the amount of transport work per unit vessel deadweight, which may change as a result of changes in average speed or cargo load factor. The Third IMO GHG Study 2014 assumes a gradual return of fleet productivity to longyear averages, through higher cargo load factors, faster sailing or a combination of both. This means that fleet productivity in 2020 is projected to be higher than in 2012.

Figure 1 presents a schematic overview of the energy demand model.

Figure 1 Schematic overview of energy demand model



4.2.2 Plausibility check of maritime energy demand modelling

Three scenarios were run using the data employed for the Third IMO GHG Study 2014. To check the plausibility of the results, the results were checked against recently available data (Table 11). The checks show that transport work in 2015 is almost the same as projected by the model. The model projects a higher rate of global GDP growth between 2015 and 2020 than the latest IMF forecast at the time of writing of this report, which will result in a higher rate of transport work growth. The rate of fleet renewal is in close agreement with the fleet renewal in the period 2012-2015.

Table 11 Scenario plausibility checks

Parameter	Plausibility check	Results
2012-2015 Growth in maritime transport work	2012-2015 maritime transport work forecast (UNCTAD, 2015)	The UNCTAD forecast for transport work in 2015 (made in October of that year) is 11% higher than transport work in 2012. The base case modelled transport work increase as 10.50%, the high case as 14% and the low case as 9.8%.
2015-2020 GDP forecasts	World Economic Outlook (IMF, 2015)	IMF projects that world GDP will increase by 20% between 2015 and 2020. The base case assumes a GDP increase of 27%, the high case 28% and the low case 25%.
2012-2020 Fleet renewal	New ships in the fleet 2012-2015 (Clarksons Research, 2016)	Clarksons reports that 18% of the ships in the fleet in December 2015 have entered the fleet in or after 2012. If fleet renewal continues at this rate, 41% of the ships in the 2020 fleet will have been built after 2012. The base case projects 45% new ships in the fleet by 2020; the high case 46% and the low case 44%.

Source: CE Delft.

The plausibility check shows that the energy demand of maritime transport in 2015 is very likely to be close to the modelled energy demand, because the share of new ships as well as the amount of transport work are close to the modelled values. In the coming years, economic growth and, by implication, transport demand growth may be lower than projected in the model if IMF forecasts are realised. This suggests that the energy demand projections and the fuel projections are more likely to be an overestimate than an underestimate of the 2020 energy demand. Still, we consider the differences to be small enough to continue to use the base case scenario of the Third IMO GHG Study 2014, while at the same time opting to develop new high and low cases, as explained in Section 4.2.3.

Details on these plausibility checks can be found in Annex D.

4.2.3 Accounting for the economic cycle

The long-term socio-economic and energy policy scenarios used in the Third IMO GHG Study 2014 were developed to analyse long-term trends and, as such, do not take into account short-term fluctuations of the business cycle. Since this study analyses the situation in 2020, less than four years after the analysis was performed, the potential impacts of the short-term economic cycle cannot be ignored, however.

Table 12 shows the fuel use and transport work of the maritime sector from 2007 through to 2012. While transport work shows a steady upward trend (with a dip in 2009), fuel use shows greater variation. Focusing on the period 2009-2012, i.e. after the start of the financial crisis and the adoption of slow steaming, Table 12 shows that the amount of fuel used per unit of transport work may be up to 13% higher or 11% lower than the average. As analysed in Section D.3, this is related to speed changes but also to changes in the cargo load factor and other parameters. Guided by these figures, we account for the economic cycle in the energy demand projections by assuming an 11% higher energy demand in the high case and an 11% lower energy demand in the low case.

Table 12 Shipping emissions and transport work, 2007-2012

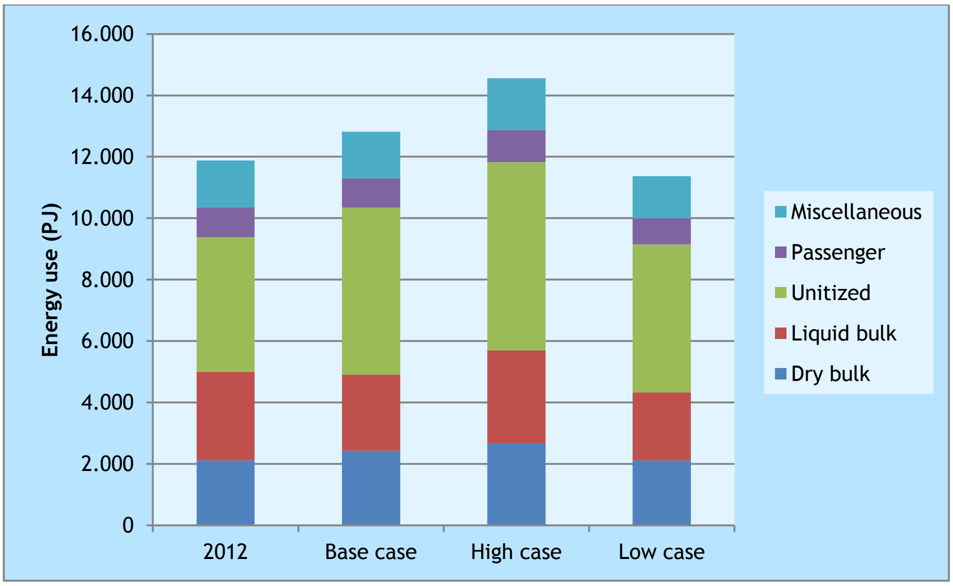
Year	Transport work	Fuel use	Fuel/unit of transport work
	Billion tonne-miles	Million tonnes	Tonne/million tonne-miles
2007	40,759	352	8.64
2008	41,926	363	8.66
2009	40,099	313	7.81
2010	44,369	293	6.60
2011	46,617	327	7.01
2012	48,864	300	6.14

Source: Third IMO GHG Study 2014 (IMO, 2014); (UNCTAD, 2015).

4.2.4 Energy demand projection model results

The energy demand of the shipping sector is projected to vary from 11.9 EJ in 2012 to 11.4- 14.6 EJ in 2020, depending on the scenario. The energy demand projection model results are presented in Figure 2. More detailed results on the number of ships and share of new ships for all 53 ship type and size categories can be found in Annex D.

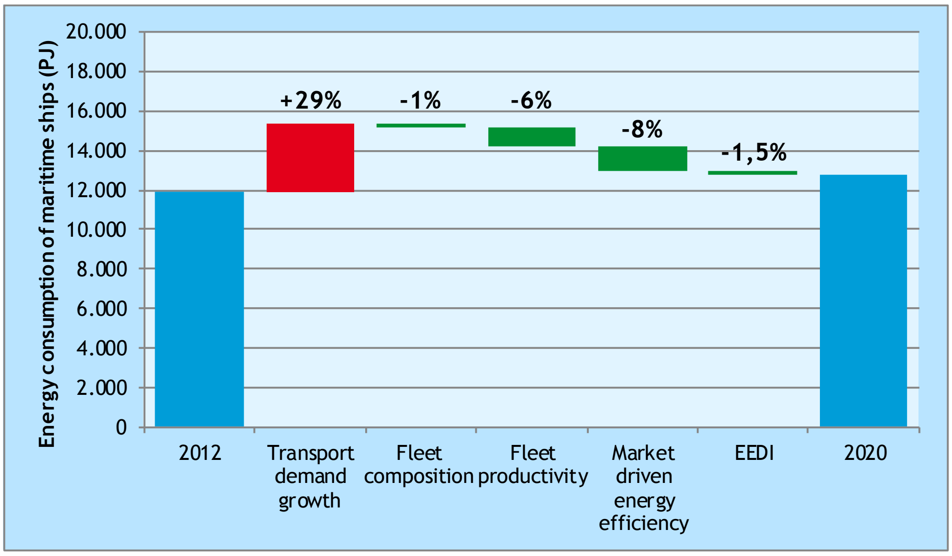
Figure 2 Energy use per ship type in 2012 and 2020



Source: CE Delft.

Figure 3 shows the contribution of the different factors to the change in energy use between 2012 and 2020. Transport demand grows by 35% and translates into a proportional change in energy demand of cargo ships.
The energy use of non-cargo ships is assumed to remain constant, resulting in an overall increase in energy demand of 29%. Because there are more large ships in the fleet in 2020, especially container ships, the energy demand is reduced by 1%. A further 6% reduction stems from higher cargo load factors as they gradually return from low 2012 values to long term averages (a process that will not be completed by 2020 in our modelling). The EEDI reduces the energy consumption by 1.5%, and market driven efficiency improvements by 8%.

Figure 3 Decomposition of changes in energy use between 2012 and 2020, base case



Source: CE Delft.

4.3 Projections of use of Exhaust Gas Cleaning Systems (EGCSs)

The projection of uptake of EGCSs and their use in 2020 is based on economic considerations, technical and operational constraints, availability of EGCSs and installation capacity, and regulatory uncertainty. We apply a five-stage filter model to each of the
53 generic ship type and size categories defined in the Third IMO GHG Study 2014:

1. Economic analysis. For each generic ship category, the costs and benefits of an EGCS are estimated. The costs are the sum of annualized capital expenditures and operational expenditures. The benefits are the savings of fuel expenditures, which depend on the price difference between low-sulphur and conventional fuels. This is discussed in more detail in Section 4.3.1.
2. Regulatory constraints to operating EGCSs. While the use of EGCSs is allowed under MARPOL Annex VI (Regulation 4) and under the national and regional ECA regulations, the discharge of washwater is sometimes constrained or prohibited because of water quality considerations.
The impact of these regulations on the business case and investments are discussed in Section 4.3.2.

3. Technical and operational feasibility. Even if the cost-benefit analysis is positive, there may be reasons why EGCSs cannot be installed on ships, e.g. because of space limitations, impacts on stability or compatibility with Tier III NO_x regulations. The impact of the technical and operational feasibility is analysed in Section 4.3.3.
4. Availability of EGCSs. Even if the cost-benefit analysis is positive and installing EGCSs is technically and operationally feasible, their availability may be limited due to the production capacity of EGCSs or the installation capacity. These are analysed in
Section 4.3.4.
5. Other constraints. Finally, there may be other considerations, discussed in Section 4.3.5, that may limit the uptake of EGCSs.

More details on the projections of the use of EGCSs are presented in Annex C.

4.3.1 Economics of EGCS use

The costs of an EGCS are the sum of the costs of investment in an EGCS and operational costs. The investment depends on type of EGCS, engine size and whether the EGCS is installed on a new ship or retrofitted on an older vessel.

There are three types of EGCS: open loop, closed loop and hybrid. Open loop EGCSs are, on average, cheaper than closed loop EGCSs, which require additional pumps, cooling units for washwater, tanks for sludge, et cetera. Hybrid EGCSs, which can operate both in open and closed loop mode, thus requiring two sets of pumps and piping, are the most expensive.

We have liaised with EGCS manufacturers and with shipping companies that have recently invested in EGCSs or studied the costs and benefits of doing so. This has resulted in an estimate of investment costs (acquisition of the EGCS and installation), as presented in Table 13.

Table 13 EGCS investment costs used in this study

EGCS type	Fixed investment costs (million USD)	Variable investment costs (USD per kW of installed engine power)
Open loop, retrofit	2.3	55
Open loop, newbuild	1.9	38
Hybrid, retrofit	2.8	58
Hybrid, newbuild	2.4	44

Source: CE Delft.

The operational expenditures of EGCSs comprise:
- the additional energy required for the pumps, heat exchangers, hydrocyclones and other equipment;
- disposal of sludge;
- maintenance;
- in the case of closed loop EGCSs and hybrid EGCSs operating in closed loop mode, consumption of caustic soda.

The estimated operational cost data used in this study, based on the stakeholder consultation, are presented in Table 14.

Table 14 **EGCS operational costs used in this study**

EGCS type	Operational costs
Open loop	1% additional fuel + USD 13,000 + 0.4 * $P_{M.E.}$ (kW)
Hybrid	0.50% additional fuel + USD 25,000 + 0.4 * $P_{M.E.}$ (kW)

Source: CE Delft.

Note: $P_{M.E.}$(kW) is the power of the main engine in kilowatt.

When evaluating investments, different shipping companies employ different methods, which fall broadly into two groups. The first, which is most common in retrofit projects, is to assess the payback time. The investment is divided by the annual sum of the operational expenditures and fuel expenditure savings. The second, which is most common for newbuilds, is to compare the annuity of the investment with the projected fuel cost savings. The annuity is calculated from the investment costs, discount rate and economic life.

Based on a stakeholder consultation, this study uses the parameters summarized in Table 15.

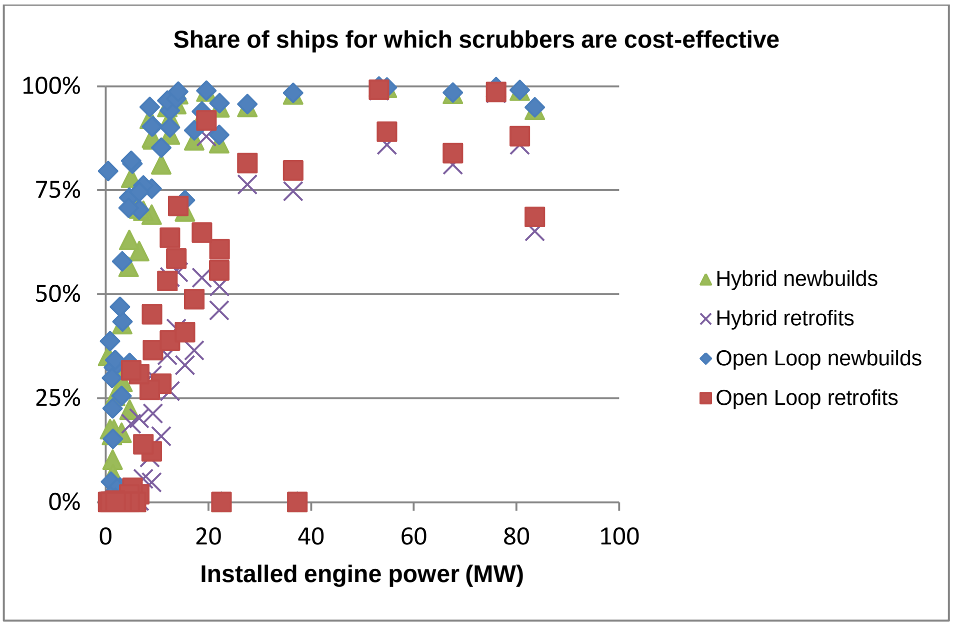
Table 15 **Financial parameters used in this study**

Newbuilds: discount rate	3%
Newbuilds: economic life	10 years
Retrofits: payback period	3 years

Source: CE Delft.

Figure 4 shows, for each of the 53 ship type and size categories used in the Third IMO GHG Study 2014, the share of ships for which EGCSs are cost-effective as a function of the total installed engine power of the ship.
For these calculations, a price difference between conventional fuels and low-sulphur fuels of USD 129 per tonne has been assumed (see Section 5.5). Figure 4 shows that for engines up to about 5 MW, retrofitted EGCSs are hardly ever cost-effective at the assumed fuel prices. For newbuilds, the share of ships for which EGCSs are cost-effective is higher. The cost-effectiveness improves for engines between 5 and 20 MW, while for most ships with over 20 MW of engine power EGCSs are a cost-effective option to comply with the sulphur limit at the assumed fuel price difference.

Figure 4 Cost-effectiveness of EGCSs as a function of engine size



4.3.2 Regulatory constraints on EGCS use

Discharge of washwater is restricted or prohibited in several ports (e.g. Antwerp, Hamburg), estuaries (e.g. the Wese) and coastal waters (e.g. Alaska, Belgium, Italy). There is an ongoing debate in several European countries about whether washwater discharges are compatible with the Water Framework Directive (EC, 2000) and the Marine Strategy Framework Directive (EC, 2008). The uncertainty resulting from this discussion currently has a negative impact on demand for EGCSs.

Based on the stakeholder consultation, we expect that shipowners that opt to invest in an EGCS will invest in a unit that can operate in a zero discharge mode when sailing in waters where discharge is prohibited. Hence, in our modelling we assume that the costs of EGCSs will be those of a hybrid EGCS.

4.3.3 Technical and operational constraints on EGCS use

Technical and operational constraints on installing EGCSs may comprise:
1. The space required for EGCSs and the impact on cargo space.
2. Impacts on vessel stability.
3. Impacts on power requirements.
4. Compatibility of EGCSs with Tier III requirements.

The evidence presented to us in the stakeholder consultation suggests that, in many cases, EGCSs can be designed to fit the available space. For ships that have free deck space available or large engine rooms, fitting EGCSs is almost never a problem. In some cases, however, cargo space may need to be sacrificed. This appears to be especially the case for container ships. For large container ships with equally large EGCSs, examples are available of EGCSs that would take up the space of a few forty-foot containers. Whether this is acceptable depends on the company.

In new ships, EGCSs can be incorporated in the design of the ship, thus eliminating space constraints.

Many small container ships and RoRo feeders have insufficient power generation capacity to retrofit EGCSs. For these ships, the installation would require expanding the power generation capacity which generally renders the investment uneconomical.

The other constraints are only of minor importance for the uptake of EGCSs, because they can be taken into account in EGCS design for both newbuilds and retrofits.

4.3.4 EGCS availability

EGCSs can be installed during regular dry dockings, though some of the work can be done while the ship is in service or in a port. Hence, as long as the demand for EGCSs does not exceed the dry docking capacity, yard availability is not a constraint. The production capacity is also not a constraint.

4.3.5 Other constraints

Many studies have shown that cost-effective solutions in shipping are not always implemented. A prime reason is the split incentive between the shipowner and the charterer. When the former makes the investment but micro-economics dictate that he will only be able to reap a share of the benefits, the business case deteriorates. Moreover, the risk of underperformance lies with the owner and he may demand an additional reward. A second reason may be financial constraints.

This study has accounted for these constraints by assuming that 25% of the ships for which an EGCS is cost-effective will nevertheless decide not to install one.

4.3.6 Conclusions on EGCSs

In summary, our analysis points to the following conclusions:

- Installation of EGCSs on ships will continue at the current rate until 2017.
- Provided that IMO decides in 2017 to uphold the 2020 implementation date for the 0.50% sulphur limit, we expect that shipowners will make the following investment decisions:
  - Small container ships and RoRo feeders will not install EGCSs, because of power limitations.
  - Shipowners will generally opt for EGCSs that can operate in zero discharge mode for a sufficient length of time, so they can operate in areas where discharges are prohibited. We have modelled this as if they opt for hybrid EGCSs.
  - In the base case, 75% of the ships built in 2018 and 2019 will be fitted with an EGCS if it is cost-effective to do so.
  - Of the existing container ships for which it is cost-effective to do so, 75% will retrofit EGCSs during their regular dry docking in the base case. The cost-effectiveness of EGCSs for container vessels takes into account that cargo space needs to be sacrificed.
  - In the base case, 75% of the other existing ships for which an EGCS is cost-effective will retrofit EGCSs during regular dry docking.
  - The total number of ships installing EGCSs will not exceed 3,000 per year due to yard availability.
  - Should IMO decide before 2017 to uphold the 2020 implementation date, this will only have a limited impact on the uptake of EGCSs, because installation prior to 2018 would imply there is hardly a return on investment for over two years.

- Should IMO decide after 2017, this will reduce the number of EGCSs installed, because lead time and yard capacity will become limiting factors.
- Installations will be scheduled as closely as possible to the implementation date of the sulphur limit. We expect installations to begin in the second half of 2018.

In total, in the base case we expect about 3,800 ships to be installed with EGCSs on 1 January 2020. Collectively, these vessels consume 36 million tonnes of HFO with a sulphur content of more than 0.50% m/m a year.

The most important assumption in the sensitivity analysis is the price difference between HFO and low-sulphur fuels. If this difference were to disappear and the other assumptions remained unchanged, demand for HFO would all but die out and demand for low-sulphur fuels would be 13% higher. Most other assumptions have a smaller impact.

In the high case, 14 million tonnes of HFO with a sulphur content of more than 0.50% m/m will be consumed by ships with EGCSs, in the low case 38 million tonnes.

4.4 Projections of consumption of alternative marine fuels

Alternative fuels are defined as fuels with a sulphur content of 0.50% m/m or less that are not derived from petroleum. The use of alternative fuels is an option for regulatory compliance. The following alternative fuel types are considered:
- LNG;
- methanol;
- biofuels;
- LPG;
- DME.

Of these alternative fuels, LNG currently has the largest market share and its possible use is therefore analysed in more detail than the uptake of the other alternative fuels, which are briefly discussed in Section 4.4.5 . We assess the share of such fuels by 2020 as negligible.

In this study we distinguish the use of LNG consumed on board gas carriers from the use of LNG as fuel market. In the former case, evaluation is based on the projected number of LNG carriers operating in 2020, which will determine LNG consumption by 2020. In the latter case, evaluation is based on a quantitative estimate using the shipping model GloTram, comprising the following steps:
- Alignment of the shipping model GloTraM with the assumptions used in this study (e.g. scrubber costs, fuel price projections, transport work).
- Sourcing of estimates for model input assumptions that could not be aligned (because of differences in model structure), using existing literature and where necessary expert judgment.
- Comparison of the total energy demand obtained with GloTraM with that obtained with CE Delft’s model, for validation of the use of GloTraM as a source for LNG demand estimates.
- Estimation of global fleet LNG consumption by 2020 by extrapolating 2020 LNG use of the fleet analysed within GloTraM (the GloTraM fleet is deemed a representative subset of the energy demand of the total fleet).

The final estimate includes both LNG use on board carriers and LNG use as a fuel market. The total use is disaggregated by region using regional shares by 2020 found in the existing literature.

More details on the model and on the resulting projections of LNG use are presented in Annex E. A comparison of the results with the LNG use projections found in the existing literature is also provided in Annex E.

4.4.1 Evaluation of LNG use by 2020

The evaluation of the use of LNG consumed on board LNG carriers is based on the projected number of LNG carriers that will be operating in 2020.
The estimated LNG use in 2012 presented in Section 3.2 is associated with the consumption of LNG in gas carriers. Approximately 8 million tonnes are estimated to have been consumed in 2012. Based on our analysis, we estimate that the number of LNG carriers that will be operating in 2020 may increase by 20-35% relative to 2012. Table 16 presents estimated LNG demand for the three cases (base, high and low) in million tonnes.

Table 16 Estimated LNG demand for gas carriers over the period 2012 to 2020 in shipping

	2012	2020 base	2020 high	2020 low
LNG consumed on board LNG carriers	8	9.8	10.8	9.7

Source: This study.

In order to evaluate the use of LNG as a fuel market by 2020, we used the shipping model GloTraM, which ensures that a number of key input assumptions are taken into account. These include:
- socio-economic developments (e.g. transport work);
- marine fuel price projections;
- LNG prices;
- costs of LNG engines, storage tanks and other required equipment;
- costs of other compliant technologies (e.g. scrubbers);
- technical aspects (e.g. efficiency, space required for LNG tanks, impact on vessel autonomy, required power of LNG engines);
- regulatory compliance.

4.4.2 LNG input assumptions

LNG has for a long time had a lower price per unit energy than conventional fuels, although there may be variations in LNG prices across world regions at any given time. In this study we performed an analysis of the potential uptake of LNG based on the assumption that up to 2020 LNG will be sold at a discounted price per unit of energy relative to HFO. The LNG price projection is provided in Table 17. LNG price is a key variable for evaluating the potential LNG market in 2020: the greater the reduction relative to the HFO and MGO price, the greater the uptake of LNG. We therefore performed a sensitivity analysis around different LNG price projections, which is presented in Annex E.

Table 17 LNG price projection used in this study (USD/tonnes)

Product	2016	2018	2020
LNG	292	462	583

Source: This study. Note: Gas is typically priced in dollars per MMBtu, but in this study we converted the LNG price in dollars per tonne of fuel by assuming the energy density of LNG to be 53.6 MJ per kg and converting MMBtu to Joules: 1 MMBtu = 0.94782 Giga Joules.

LNG-fuelled ships require higher investments than conventional vessels (CE Delft; TNO, 2015). In general, investment costs will depend on ship type and size. There are cost differences between newbuilds and retrofit. There is some evidence of retrofitting of LNG machinery, but the number of retrofits is expected to be small because of the additional costs associated with the required modifications. We therefore focus on LNG for newbuilds, as this is expected to be the predominant way the technology enters the global fleet. On new ships, the LNG fuel system can be taken into account during the design of the ship (DNV-GL, 2014); (Wärtsilä, 2012), possibly reducing the additional costs. The assumed capital cost for newbuilds used in this study is presented in Table 18.

Table 18 LNG capital costs for newbuilds used in this study

Description	Investment costs
LNG dual-fuelled engines + LNG storage system	1.40 mln USD per MW

Source: This study.

Technical constraints might influence investment decisions for LNG-powered ships. For example, there is currently a limit to the size of LNG engines, with dual-fuelled engines available up to approximately 35 MW (DNV, 2014), which is sufficient for most ships except for large container and cruise ships. However, based on our consultation, dual-fuelled engines could go up to 60-70 MW. In this analysis we assumed no constraints on the size of LNG engines.

LNG tanks require a different piping system, which, in combination with the lower energy density of LNG (compared with petroleum-derived fuels), could reduce cargo space or reduce vessel autonomy compared with conventional marine fuels. LNG on board therefore affects a ship's energy and economic performance, to an extent likely to vary according to ship type and size. In our analysis it is assumed that, in comparison with conventional marine fuels, a LNG-fuelled ship will lose 0.09 tonnes of cargo capacity per MWh of energy stored on board.

Based on an internal consultation, this study uses the financial parameters for LNG newbuilds summarised in Table 19.

Table 19 Financial parameters for LNG newbuilds used in this study

Discount rate	5%
Life time	30 years
Payback period	3 years

Source: this study.

4.4.3 LNG as a bunker fuel by 2020

For the three cases: base, high and low, estimated demand in 2020 for LNG as a fuel market is presented in Table 20. The fleet analysed within GloTraM is considered representative of the major part of the total fleet. The LNG consumption of the global fleet by 2020 was obtained by extrapolating the LNG use obtained using GloTraM.

Table 20 **Estimated LNG demand over the period 2012 to 2020 in shipping**

	2020 base	2020 high	2020 low
LNG as a fuel market	3.22	3.00	3.66

Source: This study.

Note that the designators 'high' and 'low' refer to the demand for compliant fuels, not to the consumption of LNG. A high LNG consumption results in a low demand for compliant fuels.

Based on this analysis, a total of 170 ships among dry, container and oil tanker ship types will be powered by LNG in 2020.

These results seem to be in the range of the values for LNG market size in 2020 found in the existing literature. A brief comparison is provided in Annex E.

4.4.4 Regional LNG availability and demand as a bunker fuel by 2020

There is growing availability of LNG as a bunker fuel. The existing LNG bunkering infrastructure is focused mainly in the Baltic and North Sea. In all European regions a number of planned projects will expand LNG infrastructure and increase LNG availability. As emphasized by the European Directive 2014/94, strategic refuelling points for LNG should be available at least by the end of 2030. In North America, a few ports have planned new LNG projects and additional projects are under discussion. Similarly, in the Asia-Pacific region there are ports in the Republic of Korea, China, Japan and Singapore that are offering LNG bunkering or will start doing so in the coming years. Hence, the availability of LNG as a bunker fuel is improving along the major shipping routes and will continue to improve in the coming years (see Section E.3.1).

An approximate range and average of regional shares of LNG bunkering demand has been derived and is reported in Table 21.

Table 21 **Estimated regional shares for LNG demand over the period 2012 to 2020 in shipping**

	2012	2020 average
Africa	7%	5%
Asia	24%	25%
Europe	8%	11%
North America	26%	28%
Latin America	2%	1%
Middle East	16%	15%
Russia & CIS	17%	15%
TOTAL	100%	100%

Source: This report, based on spatially explicit data analysis, LNG bunkering infrastructure data and informed by LNGi - DNV GL's intelligence portal for LNG as a shipping fuel.

4.4.5 Other alternative shipping fuels by 2020

Driven particularly by MARPOL Annex VI air pollution regulations on NO_x and SO_x emissions, a number of alternative marine fuels may see increased uptake by 2020. These alternatives include methanol, biofuels, LPG and DME.

Methanol has a low sulphur content and is widely available (albeit with little bunkering infrastructure developed for use as a marine fuel). While it can be considered an alternative to petroleum-derived low-sulphur fuels, it has several limitations from a technical and commercial perspective. Although methanol fuel systems consist mainly of familiar components, among other additions a ship requires certain modifications to engines and tanks (e.g. an inert gas system for the tanks) and methanol is therefore likely to be used only on ships specifically designed for its use (as opposed to being installed as a retrofit). Even assuming that a methanol-propelled ship requires only minor additional capital investment, methanol needs to be available and cheaper than MGO on an energy-equivalent basis for it to be commercially competitive (FCBI Energy, 2015); (DNV-GL, 2016).

According to IEA (IEA, 2011), to achieve the ambitious biofuel projections presented in its Blue Map scenario, biofuel demand needs to increase rapidly, reaching approximately 760 Mtoe (32 EJ) in 2050, but only 5 EJ in 2020, of which a share of 5% would be used as transport fuel (0.25 EJ).
The international shipping fleet could adopt biofuels by blending them with conventional marine fuels and consuming about 11% of the biofuels used in the transport sector, which corresponds to approximately 0.03 EJ (30 mln GJ). This amount represents less than 0.3% of the total energy demand of the base case estimate of this study, which makes biofuels share by 2020 negligible.

While LPG (Liquid Propane Gas) and DME are potential marine fuel candidates, there is limited information available on their viability. As LPG is a premium product, it seems to be too expensive compared with other alternative fuel options and in addition presents safety issues, which could limit its use on board ships (IEA, 2014). For LPG and DME, owing to the lack of significance of these fuels in the shipping market today, in 2016 we deem it unlikely that they will contribute significantly by 2020.

Given the above considerations, we assess that the share of other alternative shipping fuels by 2020 will be negligible.

4.4.6 Conclusions on LNG consumption

The final estimate of the use of alternative fuels in shipping by 2020 relates solely to the use of LNG, as the projected shares of other alternative fuels in 2020 is found to be negligible. Use of LNG as a fuel market and its consumption on board LNG carriers has been evaluated independently.
Total LNG consumption in 2020 is presented in Table 22, distinguishing three cases (base, high and low), which represent the sensitivity of LNG use to changes in transport demand.

Table 22 Estimated LNG demand in million tonnes over the period 2012 to 2020 in shipping

	2012	2020 base	2020 high	2020 low
LNG carriers	8	9.76	10.85	9.70
LNG as a fuel market (global fleet)	0	3.22	3.66	3.00
Total	8	13.0	14.5	12.7
Percentage of total energy demand	3.6%	5.4%	5.3%	6%

Source: This study.

Table 23 shows regional LNG demand for the three cases.

Table 23 **LNG potential regional use in 2020 in million tonnes as estimated in this study**

	2020 base	2020 high	2020 low
Africa	0.7	0.7	0.6
Asia	3.3	3.6	3.2
Europe	1.4	1.6	1.4
North America	3.6	4.1	3.6
Latin America	0.1	0.1	0.1
Middle East	2.0	2.2	1.9
Russia & CIS	2.0	2.2	1.9
TOTALS	13.0	14.5	12.7

Source: This study.

Based on our analysis we estimate that in the period up to 2020 LNG consumption may increase by 60-80% relative to 2012. We expect about 75% to be consumed by LNG carriers, with the remainder consumed by unitized, passenger vessels, dry bulk oil and chemical tankers and miscellaneous types of ship, as well as inland vessels.

4.5 Global and regional demand of maritime fuels by 2020

This section presents the base case projection of global and regional demand for maritime fuels by 2020, based on projected global maritime energy demand (Section 4.2). This energy demand can be met by four types of fuel:

1. Petroleum fuels with a sulphur content of 0.10% or less will be used in ECAs as well as in some auxiliary engines.
2. Petroleum fuels with a sulphur content of over 0.10% but no more than 0.50% will be used outside ECAs.
3. Petroleum fuels with a sulphur content of over 0.50% will be used by ships with an EGCS both inside and outside ECAs.
4. LNG will be used by LNG carriers and other ships fitted with LNG engines.

Section 4.2 estimates the global marine energy demand in the base case to be 12.8 EJ in 2020.

Section 4.3 projects the amount of fuel consumed in 2020 by ships that will be fitted with EGCSs to be 36 million tonnes of HFO, with an estimated energy content of 1.4 EJ (an overview of the energy content of fuels is provided in Annex D, Section D.1.6).

Section 4.4 projects the amount of LNG used by ships in 2020 to be 13 million tonnes, with an estimated energy content of 0.6 EJ. In order to arrive at a conservative estimate and given the uncertainties in the development of LNG infrastructure under current fuel prices, we have lowered our projections of LNG by 10% to 12 million tonnes in 2020, with an estimated energy content of 0.5 EJ. Similarly, the amount of LNG consumed in the other scenarios was revised downwards.

The remaining 10.8 EJ will need to be supplied by petroleum fuels with either a sulphur content of less than 0.10% m/m or a sulphur content between 0.10% and 0.50% m/m. 0.10% fuel is used in ECAs. While the market offers 0.10% HFO, most of this fuel is MGO. Conversely, most MGO offered has a low sulphur content.

The Third IMO GHG Study 2014 estimated that in 2012 14% of the energy provided by petroleum fuels was MGO and 86% HFO. MGO was typically consumed by smaller auxiliary engines and high-speed diesel engines, although an increasing share of auxiliary engines are fitted to be able to run on HFO.

The Third IMO GHG Study 2014 estimated that in 2012 the share of fuel used in ECAs was 6.3%. A large proportion of this fuel will be MGO, but some will be HFO (for ships fitted with a scrubber) or LNG.

It is expected that by 2020, more ships will be able to run their auxiliary engines on HFO than in 2012. In total, we expect that 15% of the energy consumed by ships that do not have an EGCS and do not run on LNG will be provided by MGO with a sulphur content of 0.10% or less and the remainder by HFO with a sulphur content between 0.10% and 0.50% m/m. This is a conservative estimate, because increasing the amount of MGO by increasing middle distillate production requires less hydroprocessing capacity and is therefore easier to realise than increasing the amount of compliant HFO.

Assuming that the regional shares of fuels do not change between 2012 and 2020, the projection of base-case marine fuel demand is presented in Table 24.

Table 24 Global and regional marine fuel demand (2020) - base case

Sulphur (% m/m)	Petroleum-derived fuels			LNG
	<0.10%	0.10-0.50%	>0.50%	
	In ECAs	Outside ECAs	Globally in combination with an EGCS	Globally
	Million tonnes per year			
Africa	2	12	1	0.6
Asia	18	110	15	3.1
Europe	9	54	8	1.2
North America	4	26	3	3.4
Latin America	3	21	3	0.1
Middle East	1	5	4	1.8
Russia & CIS	1	7	1	1.8
Global	39	233	36	12

Source: This report.

Table 25 presents global fuel demand for the low case and high case. In the low case, the demand for petroleum fuels with a sulphur content of 0.50% m/m or less is 15% lower than in the base case. In the high case, the demand for petroleum fuels with a sulphur content of 0.50% m/m or less is 24% higher than in the base case.

Table 25 **Global marine fuel demand (2020) - low case and high case**

Sulphur (% m/m)	Petroleum-derived fuels			LNG
	<0.10%	0.10-0.50%	>0.50%	
	In ECAs	Outside ECAs	Globally in combination with an EGCS	Globally
	Million tonnes per year			
Low case	33	198	38	13
High case	48	290	14	12

Source: This report.

4.6 Non-marine fuel demand

The demand forecast of refinery products is based on Stratas Advisors' database of market data, pulled from a wide variety of sources including the IEA, EIA and country reporting agencies for major global energy consumers. It takes into account key structural factors like economic growth, population, energy intensity/efficiency and urbanization.

Table 26 summarizes product demand per region and globally. Product demand, refinery configuration and refinery capacity permit assessment of whether or not petroleum and refined products trade flow is required to meet regional supply-demand balances.

In 2020, global non-maritime fuel demand will approach 4,190 million tonnes/year, versus 3,692 million tonnes/year in 2012 (Table 9, Table 26). From 2012 to 2020 global non-maritime fuel demand will increase by 13%, driven by strong growth of refined product demand in Latin American, Middle Eastern, African and Asia-Pacific markets. The majority of the remaining growth will originate in the North American region.

Table 26 **Non-Marine Refinery Product Demand (2020) - million tonnes per year(1)**

	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS	Global(2,3)
Gasoline(4)	45	277	81	421	136	76	49	1,086
Naphtha	14 (3)	145 (214)	49 (47)	16 (16)	13 (13)	45 (7)	22 (22)	305 (+17)
Jet/Kero Fuel	15	124	62	75	19	21	15	331
Middle Distillate(4)	85	524	290	233	166	126	58	1,482
LPG	2 (15)	41 (120)	12 (36)	24 (89)	11 (36)	11 (42)	9 (19)	110 (+247)
Other(5)	27	195	70	90	91	98	40	537 (+74)
Total, non-marine	190	1,454	585	925	462	371	203	3,852 (+338) =4,190

Source: Stratas Advisors, 2015-2016.

For marine (MGO/HFO) demand, which is not included in this table, see Table 24.

Numbers in brackets are LPG, Naphtha and other products produced by other installations than refineries, such as NGL plants and direct from oil production sources.

Non-marine refinery product demand is 3,852 million tonnes. 338 million tonnes is met outside refineries from NGL plants (17 as Naphtha, 247 as LPG, and 74 in others categories from other sources).
Gasoline and Middle distillate includes biofuel demand.
Includes petroleum coke, refinery fuel, non-marine fuel oil and other products.

Refinery fuels (gasoline, naphtha, jet fuel, kerosene and middle distillate) will make up 77% of global refined-product, non-marine demand in 2020. Middle distillate will be dominant, comprising 36% of the market. Gasoline will be close to this volume (26% of product demand) and jet fuel/kerosene will make up 8% of the market. Non-marine heavy fuel oils will account for 4% of product demand and LPG will make up 8% of the market. Other products, which will make up 13% of product demand, include lubricants, asphalt, refinery fuel gas, non-marine fuel oil, coke and miscellaneous products. The non-marine fuel oil market includes the heavy fuel oil used as heating oil in steam power plants, furnace/forced air heating systems and high-pressure steam boilers. Large reductions in non-marine fuel oil demand have resulted and will likely come from its substitution in power generation plants in favour of environment-friendly natural gas.

This study projects a 13% increase in total petroleum fuel demand between 2012 and 2020, translating to a compound annual growth rate (CAGR) of 1.5%. This is higher than projections in OPEC's World Oil Outlook 2015 (6.7% demand growth between 2014 and 2020, a CAGR of 1.1%); IEA's Medium Term Oil Market Report 2016 (6.5% demand growth between 2015 and 2020, a CAGR of 1.3%) and EIA's International Energy Outlook 2016 (EIA, 2016) (11% demand growth between 2012 and 2020, a CAGR of 1.3%). The main reasons for the differences between the studies are different assumptions about economic growth and the fuel economy of road transport. Chapters 5 and 6 analyze what the consequences of lower overall fuel demand would be for the supply of marine fuels.

4.7 Conclusions on 2020 fuel demand

Marine fuel demand by 2020 is driven by transport demand, fleet composition and operational efficiency, which together determine total energy demand, and by the share of fuel consumed in ECAs, the share of MGO, the share of LNG and the use of scrubbers on ships.

Marine energy demand will increase by 8% between 2012 and 2020. The mass of marine petroleum fuels will increase by 5.5% in the base case, while LNG will increase by 50% (Table 27). The amount of HFO with a sulphur content of over 0.50% m/m will decrease from 228 to 36 million tonnes in the base case. In addition, there will be demand for 233 million tonnes of HFO with a sulphur content of 0.50% m/m or less and 39 tonnes of MGO, most of which will have a sulphur content of 0.10% m/m or less.

Global fuel demand will increase from approximately 4,000 million tonnes in 2012 to approximately 4,500 million tonnes in 2020, a 13% increase. Non-marine fuel demand will increase by 13%; marine fuel demand will grow by 5% in the base case, increase by 21% in the high case and decrease by 8% in the low case.

Table 27 **Total fuel demand in 2020 (million tonnes per year)**

		Marine petroleum			Marine LNG		
	Non-marine	Base	High	Low	Base	High	Low
2012	3,692	292	292	292	8	8	8
2020	4,190	308	352	269	12	13	12

Source: This study.

5 Projections of maritime fuel supply in 2020

5.1 Introduction to the 2020 supply analysis

This chapter presents projections of maritime fuel supply in 2020. Because maritime fuels account for about 7.3% of refinery production by mass (in 2012), the modelling underlying this chapter analyses all refinery product streams.

Section 5.2 briefly describes the model used for the base case run. Section 5.3 presents the assessment of refinery capacity in 2020, which is an important constraint in the model. Section 5.4 presents another constraint, viz. the quantity and quality of the crude oil slate in 2020. Section 5.5 presents the projected product prices used by the model for optimizing refinery outputs. The results of the model run are presented in Section 5.6. Section 5.7 contains the results of the sensitivity analyses and Section 5.8 conclusions.

5.2 Fuel supply projection model

The supply model is a linear programming (LP) mathematical model that accurately describes regional refinery operations. The supply model maximizes the refinery margins while meeting the required refinery fuel volume within given quality constraints. In doing so, each model calculates refinery fuel products and inputs constrained with respect to product quality, using refinery capacity and configuration. Higher value products like gasoline and diesel are produced to meet demand, while intermediate streams of fuel oil are routed to conversion units and hydro-desulphurization units until volume and quality constraints are met. The model calculates blending volume of biofuels (ethanol, bio-diesel) and oxygenates (MTBE, ETBE) based on regional specification and availability of biofuel. Subsequently, the intermediate streams (such as hydrocracker unconverted oil) are blended to meet volume requirements of other oils. For example, once the low-sulphur fuel oil production requirement is met, the additional intermediate oil streams are then blended with high-sulphur oil streams to meet the latter's production requirement. The model maintains material balance as well as optimizing on marginal revenue. The supply model includes interregional trade flow in a purchase and sell table. Further purchase in one region is balanced in the sell from other region. For a more detailed description of the refinery model the reader is referred to Annex B.

The model comprises seven regions as indicated in Table 28. Most regions are represented as a single refinery, but North America comprises several sub-regions: all five PADDs and Canada. Refinery representation in the model is based on the known capacity of central distillation units and other refinery units in 2012 and on the capacities projected for 2020. The crude oil used in each region and the flow of intermediary and final products between regions is ensured in the model solver. The overall material balance is performed for material streams (Crude, Products) and their constituent components (Sulphur, Metal).

The model results are provided once the material balance is met, with a material imbalance error otherwise being reported. Without a material balance, the model does not yield a converged solution.

Table 28 **Regions in the supply model**

Africa
Asia
Europe
North America
Latin America
Middle East
Russia & CIS

Source: Stratas Advisors, 2015-2016.

Before assessing scenarios in 2020, each model was calibrated with a 2012 base case, as indicated in Section 3.3.

The refinery model is customized for each region taking into account historical refinery throughput, crude slate, refinery capacity and product slate. Historical data are used to calibrate the model in order to reduce the risk of over-optimization of the model.

The gas oil is required as a feedstock for FCCs and hydrocrackers, while residue serves as a feedstock for cokers, asphalt plants and residual fuel hydrocrackers. In addition to being sold as product streams, the atmospheric gas oil, vacuum gas oil and residue are also produced as intermediate streams and are modelled using conversion units, hydrocrackers, FCCs and cokers to calculate blend stock for fuel oil as well as lighter products. The conversion units convert the heavier oil fractions to lighter fractions (to be blended with gasoline and middle distillate) and leave unconverted fuel oil to be recycled back or used for fuel oil/residual fuel oil blending. The unconverted fuel oil from hydrocrackers is hydroprocessed oil, so the sulphur content is lowered.

Model runs for 2020 projections-Case 1 were based on assessing the supply of marine middle distillate oil (MGO) and demand for marine heavy fuel oil (HFO), as specified in Table 24. For assessing the availability of compliant marine fuels in 2020, the refinery products were assigned to fulfil marine fuel demand, as indicated in Table 29.

Table 29 **Refinery products categories used to assess availability of marine fuels in 2020**

Fuels categories	**Case 1**
Refinery product	Marine fuel
Marine middle distillate oil (low-sulphur)	MGO (S < 0.10% m/m)
Heavy fuel oil (% S <0.50)	HFO (S < 0.50% m/m)
Heavy fuel oil (%S > 0.50%) (high sulphur)	HFO (S > 0.50% m/m)

Source: Stratas Advisors.

5.2.1 How the model is run

The model was calibrated using 2012 EIA/IEA data for all refinery inputs (crude volume and quality, NGLs, …) and the volumes of refinery products (LPG, Naphtha, Gasoline, Middle Distillate...). Refinery capacity, utilization and configurations are at the core of the model calibration. Capacity and configuration are mostly sourced from O&G Journal data. To fine tune product and input volumes, the utilizations rates of different refinery units are allowed to vary for the model to generate a solution, thus ensuring the model does not make unrealistic assumptions about e.g. the amount of sulphur removed from products, amount of crude used or intermediary products purchased.

Before starting a model run, the global demand of refinery products is defined, with regard to both quantity and quality (including sulphur content). The crude slate is also defined and a range of quantities is assigned to each crude, as well as the sulphur content and specific gravity. Minimum and maximum amounts of each product are assigned to regions, as well as quantity ranges for different crudes.

The model is then run for each region separately. After each run, product and crude quantity ranges assigned to the other regions are reassessed and adjusted if necessary. So, for example, if a region produces more of a certain product than there is demand for in that region, the excess production is exported to other regions, taking into account trade statistics, and production in the importing regions is lowered accordingly. Transport of products and intermediary feedstocks between regions is controlled for. The model is run in iterations until the model has yielded results for all regions and a global material balance has been achieved.

In running the model, a conservative approach is taken. The utilization rates of units that are in operation both in 2012 and 2020 are capped to the 2012 values. New units have a utilization rate that cannot exceed 90% of the nameplate capacity. Only expansions that are expected to be operational by June 2019 are taken into account. Sulphur removal in hydrodesulpurization units was limited to 90% or less, depending on the grade of oil. Marine product sulphur specifications are 10% below the limit values.

5.3 Refinery capacity in 2020

Global crude distillation capacity is projected to increase from 4,630 million tonnes in 2012 to 5,020 million tonnes in June 2019 (Table 30). Major initiatives include additional large refineries/expansions in China, India and the Middle East. Additional refineries and expansions are underway and/or have been announced for all other regions, including North America, Latin America, Russia & CIS and Africa. The expansion projects include all identified new refineries, as well as expansions at existing refineries deemed highly probable to be completed. Additional details on capacity expansions are provided in Annex B.

Global middle distillate hydroprocessing capacity is expected to increase from 1,109 million tonnes per year to 1,306 million tonnes by mid-2019 (an increase of 17% relative to 2012), with this expansion occurring mainly in the Middle East, Asia, Russia & CIS and North America.

For heavy fuel oil/residual fuel oil, hydroprocessing capacity is expected to rise from 439 to 507 million tonnes per year (an increase of 15 % relative to 2012), owing mainly to expansion in the Middle East, Russia & CIS and Asia. Capacity in both Europe and North America will be slightly down, by 3%.

Table 30 Regional Refinery Capacity 30 June 2019 (change since 2012) - million tonnes per year

Crude Distillation	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS	Global
	197 (+11%)	1,630 (+9%)	723 (-9%)	1,047 (+2%)	484 (+33%)	502 (+26%)	437 (+23%)	5,020 (+8%)
Secondary Processing Units								
Light Oil Processing								
Reforming	23 (+15%)	163 (+5%)	105.9 (-8%)	186 (-6%)	29 (+5%)	58 (+52%)	61 (+15%)	626 (+3%)
Isomerization	2.8 (+100%)	13.4 (+47%)	24.3 (-8%)	38 (0%)	2.4 (0%)	22.6 (+163%)	17.8 (+324%)	122 (+30%)
Alkylation/ polymerization	2 (+54%)	17 (+9%)	14.3 (-8%)	65 (-2%)	11.2 (0%)	5 (+6%)	3.8 (+153%)	118 (+1%)
Conversion								
Coking	4.4 (-2%)	132 (+28%)	33.7 (+23%)	159 (+20%)	45 (+62%)	23 (+461%)	23 (+78%)	421 (+35%)
Catalytic cracking	16.6 (+38%)	298 (+16%)	111 (-7%)	309 (-4%)	91.6 (0%)	48.6 (+54%)	41 (+50%)	916 (+6%)
Hydrocracking	11.3 (+126%)	177 (+16%)	102 (+18%)	124 (+27%)	6.59 (+18%)	54.39 (+63%)	56 (+700%)	532 (+37%)
Hydroprocessing								
Gasoline	0 (0%)	49.9 (+73%)	20.6 (+1%)	96 (+5%)	6.22 (+196%)	15.5 (+638%)	15.7 (+362%)	204 (+38%)
Naphtha	25.5 (+9%)	163 (-1%)	175 (-8%)	272 (+10%)	47 (+53%)	68 (+33%)	59 (+13%)	810 (+7%)
Middle distillates	26.4 (+44%)	407 (+11%)	250 (-5%)	305 (+14%)	49 (+23%)	140 (+118%)	128 (+49%)	1,306 (+18%)
Heavy oil/residual Fuel	4.5 (+13%)	184 (+22%)	75 (-6%)	156 (-2%)	31.1 (+23%)	32 (+36%)	23 (+17%)	507 (+15%)

Source: Stratas Advisors, 2015-2016. On the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Note: The numbers in bracket () are capacity changes since 2012.

5.4 Crude quality and volume for each region

The crude slate used by refineries in each region comprises an indigenous-imports pool and is particular for each region. All regions primarily use indigenous oil, resorting only to crude imports if their indigenous crude does not represent the best fit for their refineries or if indigenous production does not meet their domestic demand.

The refinery crude inputs used in each region are detailed in Section B.2. The crude slate outlook to 2020 is based on Stratas Advisors' global crude outlook, trade flow outlook to 2020 and crude oil assay database.

Table 31 summarizes Stratas Advisors' best estimates of the volume and quality of crude slate processed on each region in 2020, used in model runs to assess 2020 refinery production projections (base case).

Table 31 **Refinery Input, Crude Oil and Quality (2020, (2012))**

	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Crude Oil (million tonnes per year)	136 (108)	1328 (1233)	527 (662)	932 (827)	323 (285)	448 (334)	320 (329)
API gravity	35.41 (35.92)	35.26 (35.76)	34.48 (35.71)	30.6 (30.8)	26.2 (25.2)	31.34 (31.46)	32.5 (32.5)
Sulphur %S (m/m)	0.68 (0.64)	1.07 (1.03)	1.01 (0.77)	1.59 (1.55)	1.44 (1.45)	2.01 (1.92)	1.32 (1.32)

Source: Stratas Advisors.
Note: 2012 numbers are in brackets ( ).

Africa refinery input is light sweet crude (35°API, S<0.70% m/m). Middle East refinery input is sour crude (S>1.90% m/m). Latin America refinery inputs is mostly heavy crude (<25°API) while North America refineries input is medium sour (mostly imports) and light sweet crude (mostly domestic production).

5.5 Projected Crude and Refinery Products prices

Stratas Advisors maintain price historical data on major refinery inputs and product prices. The forecasting methodology starts by assessing these data to identify major drivers influencing global benchmark prices. The model incorporates the drivers that factor in a variety of assumptions and potential scenarios. The refinery fuel prices are highly influenced by input cost (mainly crude price) and other factors such as demand, supply, GDP and geopolitical risks.

The price differences between HFO with a sulphur content of max. 1% m/m and MGO with a sulphur content of 0.50% m/m as well as MGO with a sulphur content of 0.10% m/m or less are inputs to the assessment of the uptake of scrubbers and alternative fuels.

The following prices are added as a guidance to assess the fuel price used in the model.

Table 32 **Refinery Products and Crude Oil prices (USD/tonnes except for Brent)**

Product	2010	2012	2014	2016	2018	2020
MGO 0.10% m/m SUL	672	997	896	452	552	616
Fuel oil 0.50% m/m SUL	-	-	-	-	-	595
Fuel oil 1% m/m SUL	625	918	809	390	497	569
Fuel oil 3% m/m SUL	521	741	616	252	377	466
Brent crude (USD/bbl)	80	112	99	49	63	77

Source: Stratas Advisors; CE Delft, www.bunkerindex.com.

The fuel oil sulphur quality and crude oil price are major drivers of fuel oil price. The current fuel grade of 0.10% m/m S is high-sulphur diesel and is the price benchmark for MGO (0.10% m/m S). For HFO (0.50% m/m), the price will be above the fuel oil price of 1% m/m S. The guidance of 0.50% m/m sulphur HFO is taken from 0.10% high-sulphur diesel (MGO) and 1% S (heavy fuel oil). For 2020 (Table 32) the 0.50% HFO price is guided entirely by 0.10% high-sulphur diesel (MGO) and fuel oil 1% m/m SUL. Depending on the demand supply gap, the price will remain between the price of 0.10% S MGO and 1% S HFO, maintaining a price differential of about $ 47/tonne.

5.6 Projection results: base case

The calibrated model developed for 2012 was updated using the following information for the base case for 2020:

1. Regional refinery capacities were updated as detailed in Section B.4.1.
2. The capacity of hydroprocessing units (hydrocrackers, FCC gasoil feed hydrotreating, residue hydrocracking (HOL) and gasoil hydrotreating) were downsized to 90% in order to give a realistic representation of capacity utilization (90% max.) in various regions (see Table 35).
3. The sulphur removal in hydrodesulphurization units (such as gas oil hydrotreaters, residual hydrotreaters and atmospheric oil hydrotreaters) was limited to 90% or less (Table 36).
4. Fuel specifications were updated for 2020, based on the information in Section B.4.3. The MGO/HFO sulphur specification was further tightened by 10% For HFO the max. specification of 0.50% m/m S was thus reduced to 0.45% m/m S, and for MGO from 0.10% to 0.09% m/m S. This was done to guarantee a certain margin in the model.
5. Based on 2020 demand numbers, the maximum and minimum of refinery products and refinery inputs range were updated.
6. The price for 2020 was updated. Fuel oil and crude updated prices are reported in Table 32.

Table 33 and Table 34 summarize the global and regional refinery projections for 2020, including marine fuels. The projections show that global supply will just be able to meet global demand for marine fuel oils in 2020 in terms of both quantity and sulphur specification.

Table 33 Global Refinery Production (2020 (2012)) - million tonnes per year

Refinery Production (Base case - 2020 (2012)) (1, 2, 3)		
	Production in 2020 (2012)	Demand in 2020 (2012)
Gasoline	1,086 (963)	1,086 (963)
Naphtha	305 (256)	305(3) (256)
Jet/Kero Fuel	331 (324)	331 (324)
Middle Distillate	1,521 (1,316)	1,521 (1,316)
of which MGO (S ≤ 0.10% m/m) (4)	39 (64)	39 (64)
Total Marine Heavy Fuel Oil (HFO)	269 (228)	269 (228)
Marine HFO (S ≤ 0.50% m/m) (5)	233 (0)	233 (0)
Marine HFO (S > 0.50% m/m)	36 (228)	36 (228)
Non-marine Heavy Fuel Oil (6)	194 (272)	194 (272)
LPG	110 (113)	110(3) (113)
Other (7)	537 (784)	537 (784)
Total (marine + non-marine, refinery only)	4,159 (3,984)	4,159 (3,984)
Total (non-Marine only from refinery)	3,852 (3,692)	3,852 (3,692)

Source: Stratas Advisors; CE Delft.
(1) Production numbers in brackets () are 2012 numbers from Table 4 and Table 5.
(2) Demand numbers are from Table 4 and Table 26.
(3) For LPG, naphtha and other products demand is also met from NGL (Natural Gas Liquids) plants, coal mining and upstream, the table shows only demand met from refineries.
(4) Note that this is just MGO with a sulphur content of 0.10% m/m or less. Low-sulphur marine HFO also contains low-viscosity fuels.
(5) Some of these fuels have a sufficiently low viscosity to be used in small main engines and auxiliary engines instead of MGO.

(6) Non-marine fuel oil is intended for a well-defined industrial market (power plants, high pressure steam boilers, etc.).
(7) Includes petroleum coke, lubes, asphalt, other oils and miscellaneous products.

The various factors impacting the supply of marine fuel oil (both MGO and HFO) are discussed below:

– Capacity:
  - Crude Distillation Units (CDU): CDU capacity is set to increase globally by 390 million tonnes (8%), with the exception of Europe.
    The additional CDU capacity adds to capacity for atmospheric and vacuum gas oil and residue, adding in turn to fuel oil volume.
  - Hydrocracking: Globally, hydrocracking capacity will increase by 144 million tonnes (37%). The unconverted gas oil from hydrocrackers is already hydroprocessed and helps lower heavy fuel oil sulphur after blending. It also produces blend stock for middle distillate marine fuel (MGO).
  - Middle distillate hydroprocessing is set to increase globally by 197 million tonnes (17%), helping to meet the low-sulphur requirement for MGO.
  - Heavy oil/residual fuel capacity will increase globally by 68 million tonnes (15%).
    The increase in residue hydroprocessing helps reduce sulphur from heavy oil/ residue. The 15% capacity increase will help reduce the sulphur from heavy oil of high sulphur content.
  - Catalytic cracking capacity is set to rise by only 6% globally, Compared with 8% for CDU. This helps ensure an additional volume of gas oil will be available for marine fuel oil and middle distillate, provided diesel demand is already met.

In addition to the catalyst replacement cost, the hydrogen (H_2) cost is the major expense associated with fuel oil desulphurization. However, fuel oil blends comprise mainly light distillates when the lowering of fuel oil sulphur content of is the aim. In this regard the refinery supply model calculates the H_2 consumption (see Section B.2) in the whole plant and each specific unit. Globally, H_2 consumption increases owing to the overall tightening of the sulphur fuel specification in middle distillate oil. Refiners anyway have to meet the hydrogen consumption requirement calculated when capacity is added. Furthermore, hydrogen is also available from flashed streams, which are recycled back for hydroprocessing, in addition to hydrogen available from steam and naphtha reformers.

Table 34 **Base case for Regional Refinery Production (2020, (2012)) - million tonnes per year**

Refinery Production [1]							
	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Gasoline	22 (17)	236 (234)	120 (135)	472 (399)	104 (78)	80 (50)	52 (51)
Naphtha	14 (12)	145 (130)	49 (38)	16 (12)	13 (11)	45 (33)	22 (20)
Jet/Kero Fuel	10 (9)	120 (119)	43 (49)	84 (73)	21 (17)	36 (42)	18 (15)
Middle Distillate	51 (34)	513 (453)	269 (280)	304 (257)	103 (105)	166 (98)	115 (89)
Of which: MGO <0.10 % m/m S	2 (3)	18 (31)	9 (15)	4 (7)	3 (6)	1 (1)	1 (2)

Refinery Production (1)							
	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Marine HFO <0.50% m/m S	9 (0)	104 (0)	55 (0)	17 (0)	24 (0)	18 (0)	7 (0)
Marine HFO >0.50% m/m S	1 (7)	15 (95)	8 (52)	3 (21)	3 (18)	4 (25)	1 (10)
Non-marine Heavy Fuel Oil	15 (21)	11 (6)	2 (32)	13 (13)	49 (53)	70 (67)	34 (80)
LPG	2 (2)	41 (41)	12 (17)	24 (21)	11 (8)	11 (5)	9 (18)
Other products(2)	9 (7)	58 (188)	44 (89)	101 (128)	64 (50)	20 (22)	47 (28)
Total	133	1,233	602	1,036	392	449	306

Source: Stratas Advisors, 2015-2016.
(1) Numbers in brackets () are for 2012. 2012 production numbers are from Table 9.
(2) Includes petroleum coke, lubes, asphalt, other oils and miscellaneous products.

Table 35 shows the regional refinery capacity utilization for major units in 2020 and, for comparison, in 2012. In most regions, the hydrocracker and hydrotreatment units have utilization rates that are very similar or lower than in 2012, with the obvious exception of regions that did not have these units in 2012.

Table 36 shows the input assumptions on sulphur removal. As noted above, the values were chosen conservatively, which is why they are often lower than the corresponding values obtained in the model calibration for 2012. The values assume that all hydrocracking and hydroprocessing units come with sufficient sulphur plant capacity in order to convert hydrogen sulfide in elemental sulphur. Sulphur plants usually have a higher capacity, so that the operation of the hydroprocessing units is not constrained, this is not always supported by our data analysis, however (see Section B.5.1). If this assumption is not accurate, refineries will need to expand the capacity of their sulphur plants capacity to fulfill 2020 demand.

Table 35 Percentage Regional Refinery Capacity Utilization for major units (2020 and 2012) (1,2,3)

PROCESS	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
CDU	57% (56%)	68% (76%)	60% (76%)	64% (64%)	55% (72%)	74% (77%)	60% (85%)
HYDROCRACKER	83% (92%)	76% (69%)	83% (92%)	69% (77%)	83% (89%)	83% (92%)	56% (92%)
GOHDS TOTAL	0% (0%)	83% (91%)	83% (57%)	81% (84%)	65% (33%)	83% (92%)	75% (92%)
ATRES HDT	0% (0%)	83% (23%)	83% (46%)	10% (2%)	0% (0%)	46% (92%)	0% (0%)
H-OIL	83% (92%)	83% (92%)	83% (52%)	76% (36%)	0% (0%)	83% (92%)	36% (84%)
GASOIL HDS	81% (92%)	51% (92%)	83% (92%)	13% (10%)	83% (0%)	0% (0%)	0% (0%)
AGO HDS	81% (92%)	30% (92%)	83% (92%)	2% (6%)	83% (0%)	73% (0%)	0% (0%)
LCO HDS	0% (0%)	22% (0%)	0% (0%)	11% (5%)	0% (0%)	2% (0%)	0% (0%)

PROCESS	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
DELAYED COKER	83% (0%)	48% (75%)	46% (87%)	70% (88%)	55% (81%)	83% (92%)	38% (71%)
FCC	92% (92%)	66% (69%)	70% (81%)	92% (80%)	82% (63%)	92% (92%)	78% (92%)
REFORMER	68% (66%)	58% (70%)	65% (92%)	83% (83%)	80% (83%)	86% (70%)	55% (61%)
ISOMERISATION	28% (92%)	92% (92%)	62% (92%)	92% (64%)	35% (4%)	11% (92%)	13% (92%)

Source: Stratas Advisors, 2015-2016.

(1) 2012 and 2020 utilization rates are based on 92% of stream day capacity (92% of stream day capacity is about 8,000 hrs of continuous operation out of 8780 hrs maximum a year).

(2) 2020 Utilization is calculated based on 90% capacity of hydroprocessing units.

(3) 0% utilization is for regions where no capacity is reported for the processing in question.

Table 36 Percentage[1, 2] of sulphur removal on fuel for selected hydrotreating processes - 2020 (2012)

Regional Process Sulphur Removal Percentage (2020, (2012))							
PROCESS	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
HYDROCRACKER[1]	100% (100%)	100% (100%)	100% (100%)	100% (100%)	100% (100%)	100% (100%)	100% (100%)
GOHDS TOTAL[1]	0% (0%)	87% (93%)	86% (96%)	89% (96%)	86% (93%)	87% (98%)	87% (94%)
ATRES HDT [1]	0% (0%)	89% (89%)	89% (89%)	90% (89%)	0% (0%)	89% (89%)	0% (0%)
H-OIL[1]	81% (78%)	87% (86%)	86% (82%)	90% (89%)	0% (0%)	91% (91%)	86% (86%)
GASOIL HDS [1]	85% (97%)	83% (85%)	85% (97%)	88% (96%)	85% (0%)	85% (0%)	0% (0%)
AGO HDS [1]	85% (97%)	83% (85%)	85% (97%)	88% (96%)	85% (0%)	85% (0%)	0% (0%)
LCO HDS [1]	0(0%)	0% (0%)	0% (0%)	88% (96%)	85% (0%)	0% (0%)	0% (0%)

Source: Stratas Advisors, 2015-2016.

(1) Percentage sulphur removal in fuel oil is limited to 90% or less for 2020.

(2) Percentages are rounded to the nearest integer; therefore 100% sulphur removal does not mean total sulphur removal. When 0% is indicated, it means either non-existent or unused capacity.

At the regional level (Table 37), Africa, Asia and North America will be short of HFO (<0.50%) to fulfil demand. These regions will be able to import HFO (<0.50%) from Europe, Latin America and Middle East, which will have a supply surplus.

Table 37 **Global marine fuel demand and supply (2020) base case - million tonnes per year**

Base case marine fuel demand 2020 (supply)				
Sulphur (% m/m)	**Petroleum-derived fuels**			**LNG**
	<0.10%	**0.10-0.50%**	**>0.50%**	
Africa	2 (2)	12 (9)	1 (1)	0.6
Asia	18 (18)	110 (104)	15 (15)	3.1
Europe	9 (9)	54 (55)	8 (8)	1.2
North America	4 (4)	26 (17)	3 (3)	3.4
Latin America	3 (3)	21 (24)	3 (3)	0.1
Middle East	1 (1)	5 (18)	4 (4)	1.8
Russia & CIS	1 (1)	7 (7)	1 (1)	1.8
World	39 (39)	233 (233)	36 (36)	12

Source: Stratas Advisors, 2015-2016.
Because of rounding values may not add to totals.
Supply model results are in brackets.

Stratas Advisors' fuel oil trade flow outlook to 2020 suggests that North America could import HFO (<0.50%) from Latin America, and Europe. Africa could import HFO (<0.50%) from Middle East. Asia could import HFO (<0.50%) from Middle East (Table 38).

Table 38 **Trade flows of HFO <0.50 m/m S % for (2020), million tonnes per year**

From/to l (S<0.50%)	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Middle East	3	6	0	4	0	0	0
Europe	0	0	0	1	0	0	0
Latin America	0	0	0	3	0	0	0

Source: Stratas Advisors. 2015-2016.

5.7 Projection results: sensitivity analysis

The supply model runs were organized around a base case scenario with sensitivities as shown in Table 39. The cases include the high and low case, as well tests of the maximum amount of compliant fuel (petroleum fuels with a sulphur content of 0.50% m/m or less) that can be produced and sensitivities with regards to the sulphur content of the crude oil slate. A further explanation of each model run is provided below the table.

Table 39 Supply model runs to assess availability of marine fuels in 2020 - million tonnes per year

Scenario	Fuel sulphur content			Notes
	<0.10 % SUL m/m	<0.50 % SUL m/m	>0.50 % SUL m/m	
Case 1 - Base case demand (production)	39 (39)	233 (233)	36 (36)	Base case
Case 2 - Flash point demand (production)	39 (39)	233 (233)	36 (36)	Sensitivity Lower flash point
Case3 - High demand case (production)	48 (48)	290 (290)	14 (14)	High demand case
Case 4 - Low demand case (production)	33 (33)	198 (198)	38 (38)	Low demand case
Case 5 - Maximum production case (production)	(48)	(296)	(14)	Largest (Maximum) production of compliant oil
Case 6 - High-sulphur Case (production)	(39)	(233)	(36)	Sensitivity Blending of high-Sulphur crude 10% increase on %S m/m in crude slate
Case 7 - Low viscosity case (production)	(39)	(233)	(36)	Sensitivity Increasing low viscosity blending stocks (Kerosene, light gas oil)
Case 8 - Maximum non-marine fuel demand case (production) (2020)	(39)	(233)	(36)	Sensitivity maximum Middle distillate and gasoline production by maximizing utilization

Source: Stratas Advisors, 2015-2016; CE Delft.

(1) Numbers in bracket () are production numbers for 2020, numbers not enclosed in brackets are the demand number for 2020.

The supply model was used to estimate the ability of the refinery industry to supply the projected demand of marine and non-marine fuels in 2020 as per the scenarios outlined in Table 39 and discussed individually in subsequent subsections.

5.7.1 Case 1: base case

Case 1 is the base case. It uses the capacity projected for 30 June, 2019 and assesses the global MGO and HFO fuel supply. It assumes the base case demand shown in Table 24 for marine fuel and in Table 26 for non-marine fuel, given that both MGO and HFO marine fuels are integral elements of total middle distillate and fuel oil demand, respectively. For assessing marine fuels availability, the sulphur content in high-sulphur middle distillate (MGO 0.10% S m/m), low-sulphur fuel oil (HFO S <0.50% m/m) and high-sulphur fuel oil (HFO >0.50% S m/m) were specified in the model input to calculate marine fuels sulphur demand. The crude slate is specified in Section B.4.4.

In this base case, production is in line with demand for both MGO and HFO. For low-sulphur HFO (<0.50% S m/m), the blend stock includes residue, cutter stock, unconverted hydrotreated oil, treated light distillate and very small fractions of kerosene in some cases.

Section 5.6, Table 36, provides details about hydrodesulphurization conversion for different units. Hydrocracker unconverted oil contains almost no sulphur, but other hydrotreater sulphur removal rates are between 80-90%. Africa has no reported capacity for atmospheric residue hydrotreaters and conversion is reported as 0%.

More detailed results are provided in Section B.5.1.

5.7.2 Case 2: low flash point

This case assesses fuel availability if the minimum flash point were to be lowered from 60 to 52°C. It assumes the base case demand shown in Table 24 for marine fuel and Table 26 for non-marine fuel, given that both MGO and HFO marine fuels are integral elements of total middle distillate and heavy fuel oil demand, respectively. For assessing marine fuels availability, low-viscosity fuel oil (HFO) volume was increased to meet the marine fuels sulphur specification indicated in Table 26.

Section B.2 provides details about the low-sulphur fuel oil (HFO S <0.50% m/m) blend stock. The blend stock is mostly residue, unconverted oil from hydrocrackers, hydrotreated oil and hydrotreated light distillate. These blend stocks are only available for fuel oil after meeting middle distillate demand, and regional refineries can divert treated hydrotreated oil to the fuel oil pool. The model output gives no indication of a flash point issue.

While the minimum flash point of most of the blend stock is over 60°C, that of kerosene varies from 38°C to 70°C. Refiners must ensure a minimum flash point for the fuel blend stock as per specification, as North America and Middle East have less than 2% of kerosene stream blending into fuel oil. Further reducing the minimum flash point to 52°C will certainly help improve fuel oil availability, if kerosene can be used to meet volume requirements.

More detailed results are provided in Section B.5.2 for HFO blending.

5.7.3 Case 3: high demand case

This is the high-demand case. For assessing marine fuels availability, non-marine fuels refinery production was handled as in the base case (Case 1). Under this demand scenario, Asia and Middle East produce all additional marine fuels, because these regions will have sufficient capacity (Table 40). Furthermore, these regions enjoy greater flexibility with the crudes available to them (both volume and quality).

Each region will be able to supply MGO and high-sulphur marine HFO (>0.50% m/m S). However, Europe, Africa, Latin America, Russia & CIS and North America will be in short supply for marine low-sulphur HFO (<0.50% S m/m), which can be supplied from the Middle East. In this high -demand case, Asia will be self-sufficient (Table 41).

Table 40 Global marine fuel demand and supply (2020) high case - million tonnes per year

Marine Fuels Case 3: High marine fuels demand (supply)				
Sulphur (% m/m)	Petroleum-derived fuels			LNG
	<0.10 % SUL m/m	<0.50 % SUL m/m	>0.50 % SUL m/m	
Africa 2020 Demand 2020 Production	2.40 (2.40)	14.49 (8.77)	0.41 (0.41)	0.00
Asia 2020 Demand 2020 Production	22.60 (22.60)	136.17 (135.75)	5.68 (5.68)	3.59
Europe 2020 Demand 2020 Production	11.06 (11.06)	66.64 (55)	3.11 (3.11)	3.88
North America 2020 Demand 2020 Production	5.29 (5.29)	31.87 (17.24)	1.22 (1.22)	2.49
Latin America 2020 Demand 2020 Production	4.33 (4.33)	26.08 (24)	1.08 (1.08)	0.81
Middle East 2020 Demand 2020 Production	0.96 (0.96)	5.79 (42.09)	1.49 (1.49)	0.81
Russia & CIS 2020 Demand 2020 Production	1.44 (1.44)	8.69 (7.02)	0.54 (0.54)	0.00
World 2020 Demand 2020 Production	48 (48)	290 (290)	14 (14)	11.57

Source: CE Delft; Stratas Advisors, 2015.
Supply model results are in brackets.

For assessing marine fuels availability, marine fuels refinery production was handled as in the base case (Case 1).

Table 41 Global marine fuel trade flow (2020) - million tonnes per year

Trade flow fuels with a sulphur content of 0.50% m/m or less From/to	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Middle East	5	0	12	15	2	0	2

Source: Stratas Advisors, 2015-2016.

The crude volume was increased for high demand case in both Asia (1,312 million tonnes. For the high-demand case, crude volume was increased in both Asia (1,312 million tonnes instead of 1,267) and the Middle East (502 million tonnes instead of 448). H_2 consumption and sulphur production were likewise increased. In Asia the former was increased from 7,526 to 7,705 MMSCFD, relative to base case, in the Middle East from 2,827 to 2,889 MMSCFD. The increased H_2 consumption is to meet the higher demand for low-sulphur fuel.

The blend component for HFO takes the naphtha/kerosene swing for the high case and will impact the flash point, as the naphtha/kero swing flash point is 40-70°C. Refineries will therefore need to ensure that the flash point of their blending components are over 60°C.

More detailed results are provided in Section B.5.3.

5.7.4 Case 4: low demand case

This case assumes low demand for assessing marine fuels availability, non-marine fuels refinery production was handled as in the base case (Case 1). Under this demand scenario, marine fuels demand and production were as presented in Table 42.

Table 42 Global marine fuel demand and production - low case (2020) million tonnes per year

Marine Fuels Case 4 (Low-demand case for marine fuels)				
Sulphur (% m/m)	**Petroleum derived fuels**			**LNG**
	<0.10 % SUL m/m	**<0.50 % SUL m/m**	**>0.50 % SUL m/m**	
Africa 2020 Demand 2020 Production	1.65 (1.65)	9.92 (8.77)	1.14 (1.14)	0.00
Asia 2020 Demand 2020 Production	15.48 (15.48)	93.26 (69.66)	15.96 (15.96)	4.07
Europe 2020 Demand 2020 Production	7.57 (7.57)	45.64 (55)	8.74 (8.74)	4.40
North America 2020 Demand 2020 Production	3.62 (3.62)	21.83 (17.24)	3.42 (3.42)	2.83
Latin America 2020 Demand 2020 Production	2.96 (2.96)	17.86 (24.00)	3.04 (3.04)	0.92
Middle East 2020 Demand 2020 Production	0.66 (0.66)	3.97 (17.54)	4.18 (4.18)	0.92
Russia & CIS 2020 Demand 2020 Production	0.99 (0.99)	5.95 (7.02)	1.52 (1.52)	0.00
World 2020 Demand 2020 Production	32.93 (32.93)	198 (198)	38.01 (38.01)	13.14

Source: CE Delft; Stratas Advisors, 2015.
Supply model results are in brackets.

Each region will be able to supply MGO and high-sulphur marine HFO (>0.50% m/m S). However, Asia, Africa and North America will be in short supply for marine low-sulphur HFO (<0.50% m/m S), which can be supplied from other regions.

Asia will be able to reduce production of low-sulphur fuel oil (HFO <0.50%S m/m). Asia refinery crude input is projected to decrease from 1,328 to 1,294 million tonnes, with minor changes to crude API and sulphur.

Compared with the base case, sulphur production decreases in the Middle East and increases in Asia. In Asia, H_2 consumption increases slightly from 7,759 to 7,787 MMSCFD, owing to a slightly higher volume being processed in hydrocrackers and a higher volume in gasoil hydrotreatment (SDDG) relative to the base case. The reduced sulphur production is a result of the lower demand for low-sulphur fuel.

In Asia, capacity utilization also decreases for most of the major processing units except delayed coker and LCO HDS, as feedstock availability increases towards coker.

The blending components move towards heavier product, with 15% of treated light distillate being replaced by 9% of naphtha/kero swing and the rest replaced by hydrotreated oil blend

More detailed results are provided in Section B.5.4.

5.7.5 Case 5: maximum amount of compliant marine fuels

This case assesses the maximum amount of compliant marine fuels that can be produced given projected refinery capacity in 2020. For assessing marine fuels supply, non-marine fuels refinery production was handled as in the base case (Case 1).

Asia and Middle East will be able to supply a greater volume of compliant fuel oil thanks to the additional refinery capacity added by mid-2019. Asia will be able to increase output of HFO (<0.50% S), but will need sweeter crude to process. The maximum supply is indicated in Table 43.

Table 43 **Asia and Middle East marine fuel maximum production (2020) - million tonnes per year**

Marine Fuels Case 5 (Marine Fuel Maximum Production)(1)			
Sulphur (% m/m)	Petroleum-derived fuels		
	<0.10 % SUL m/m	<0.50 % SUL m/m	>0.50 % SUL m/m
Asia 2020 Demand 2020 Production	23 (23)	136.17 (135.75)	6.0 (6)
Middle East 2020 Demand 2020 Production	0.96 (0.96)	5.79 (42.09)	1.49 (1.49)

Source: CE Delft, Stratas Advisors, 2015-2016.
(1) 2020 Production numbers are in brackets (); demand numbers are not bracketed.

Compared with the base case, Asia refinery input sulphur will have to decrease by 2% (1.07 to 1.05) and refinery crude input increase from 1,328 to 1,371 million tonnes per year. Middle East refinery sulphur input will remain almost the same, with minor adjustments for sulphur and API.

Capacity utilization increases further in Asia for all processing units. In the Middle East, atmospheric residue hydrotreater utilization increases. In Asia, higher coker utilization indicates availability of high-sulphur residue oil for processing.

In the Middle East, H_2 consumption and sulphur production both increase. In Asia, the H_2 consumption increases significantly from 7,759 to 8,238 MMSCFD, relative to the base case. Sulphur production decreases, however, as crude slate becomes sweeter to maximize production.
There is little change in the HFO blend.

More detailed results are provided in Section B.5.5.

5.7.6 Case 6: the impact of high-sulphur crude

This case assesses the uncertainty of the quality of future crude oil production by studying the impact of worsening the quality of the crude oil processed (higher-sulphur crude). For assessing marine fuels availability, non-marine fuels refinery production was handled as in the base case (Case 1).

The Middle East, Africa, Asia and Europe regions will be able to meet the demand for all fuels when crude has a 10% higher sulphur content than in the base case (see Table 31). Russia & CIS, Latin America and North America are projected to have difficulties meeting the fuel specification with respect to diesel and/or gasoline. For example, the Russia & CIS region will have difficulty meeting the gasoline sulphur specifications if the sulphur content of the crude increases, while Latin America will have a problem meeting the ultra-low-sulphur diesel fuel specification. Compared with the base case, the Middle East could process up to 10% higher sulphur in the crude (2.22%S m/m).

From the capacity point of view, the Middle East will be able to absorb a 10% rise in sulphur increase in crude; refiners will increase their production of other products, however, as production is dynamic with regard to meeting distillate and gasoline demand. Owing to higher crude consumption for other products, CDU utilization will be higher, though utilization of other processing units will be close to the base case.

The low-sulphur blending component will increase towards hydrotreated oil, while the treated atmospheric residue blending fraction will decrease owing to heavier sour crude slate.

More detailed results are provided in Section B.5.6.

5.7.7 Case 7: increasing low-viscosity blend stock in HFO

This case assesses adding/increasing low-viscosity blend stocks towards low-sulphur fuel oil (HFO<0.50%S m/m). By increasing kerosene blending into the diesel pool and blending light gas oil and light cracked naphtha into the distillate pool, fuel oil production will increase. After fulfilling kerosene demand, the supply model shifts the remaining fractions to the diesel blend pool. After meeting gasoline demand, the additional light cracked naphtha will be shifted towards distillate fuels. For assessing marine fuels availability, marine fuels refinery production was handled as in the base case (Case 1).

Low-viscosity blend stock is needed for increasing the volume of low-sulphur HFO (<0.50% m/m S). In the high Case 3 and maximum Case 5, the amount of blend stock needed is included in the model.

More detailed results are provided in Section B.5.7.

5.7.8 Case 8: maximum refinery utilization

This case assesses maximum middle distillate and gasoline production by hydrocracker, coker, VGO hydrotreater, residual desulphurization, visbreaker and oligomerization utilization. By running refinery conversion units at maximum utilization, the higher yields of desired product (middle distillate and gasoline) are assessed here. For assessing non-marine fuels availability, marine fuels refinery production was handled as in the base case (Case 1).

Table 44 presents the maximum refinery production per region. North America, Latin America and Middle East have sufficient capacity to increase the output of middle distillates. Africa, Europe and Middle East can increase their output of gasoline. Overall, most regions can increase their output, with total production 2.6% higher by mass than assumed in the other cases.

Table 44 Regional Refinery Maximum Production 2020 - million tonnes per year

	Refinery Production (1)							
	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS	Total
Gasoline	26 (22)	236 (236)	146 (120)	474 (472)	123 (104)	86 (80)	52 (52)	1,143 (1,086)
Naphtha	14 (14)	145 (145)	49 (49)	16 (16)	13 (13)	45 (45)	22 (22)	305 (305)
Jet/Kero Fuel	10 (10)	120 (120)	43 (43)	84 (84)	21 (21)	36 (36)	18 (18)	331 (331)
Middle Distillate	53 (51)	513 (513)	269 (269)	321 (304)	120 (103)	174 (166)	115 (115)	1,565 (1,521)
Of which MGO <0.10% S m/m (2)	2 (2)	18 (18)	9 (9)	4 (4)	3 (3)	1 (1)	1 (1)	39 (39)
Marine HFO <0.50% S m/m (3)	9 (9)	104 (104)	55 (55)	17 (17)	24 (24)	18 (18)	7 (7)	233 (233)
Marine HFO >0.50% S m/m	1 (1)	15 (15)	8 (8)	3 (3)	3 (3)	4 (4)	1 (1)	36 (36)
LPG	2 (2)	41 (41)	12 (12)	24 (24)	11 (11)	11 (11)	9 (9)	110 (110)
Other(4)	24 (24)	68 (68)	46 (46)	115 (115)	113 (113)	90 (90)	81 (81)	537 (537)
Total	138 (133)	1,241 (1,241)	628 (602)	1,055 (1,036)	392 (392)	463 (449)	306 (306)	4,260 (4,159)

Source: Stratas Advisors, 2015-2016.
(1) Numbers in brackets () are the base case (Case 1) production number for 2020. Unbracketed numbers are 2020 maximum production numbers.
(2) Note that this is just MGO with a sulphur content of 0.10% m/m or less. Low-sulphur marine HFO also contains low-viscosity fuels.
(3) Some of these fuels have a sufficiently low viscosity to be used in small main engines and auxiliary engines instead of MGO.
(4) Includes petroleum coke, lubes, asphalt, other oils and miscellaneous products.

More detailed results are provided in Section B.5.8.

5.8 Conclusions on 2020 fuel supply

The modelling results indicate that the refinery industry can produce sufficient amounts of marine fuels of the required quality in the base case, the high case and the low case while at the same time supplying other sectors with the petroleum products they require.

Maritime fuel demand can also be met when the minimum flash point for marine fuels is lowered from 60 to 52°C. Only in the Middle East can regional demand production be met if the crude slate contains 10% more sulphur; other regions have insufficient capacity. The maximum amount of compliant fuels that the global refinery industry can produce is 24% above the demand projected in the base case and 2% above the demand projected in the high case. This maximum amount can only be produced if the crude slate is sweeter than in the base case, especially in Asia.

Although the utilization rates of the major conversion units will need to be high, they remain within realistic limits. We have assumed that all units have sufficient sulphur plant capacity because this is generally the case. If this assumption is not accurate, refineries will need to expand the capacity of their sulphur plants capacity to fulfill 2020 demand.

In all cases, but especially in the high-demand case, interregional transport of marine fuel will be required. If supply and demand is to be balanced in all regions, the Middle East and in some cases Europe and Latin America may have to export fuel with a sulphur content of 0.50% m/m or less to other regions.

6 Assessment of fuel oil availability

6.1 2020 assessment introduction

This chapter presents our assessment of maritime fuel availability in 2020 under the assumption that MEPC will decide to maintain the 2020 date for implementation of the global sulphur limit of 0.50% m/m. It compares the demand projections of Chapter 4 with the results of the supply modelling of Chapter 5 with the aim of assessing whether the refinery industry can and will produce enough to meet demand. It also considers under what circumstances demand or supply could evolve differently from expected and how this would impact on the assessment. Finally, the chapter discusses possible implications of occurrences of global or regional over- or undersupply.

6.2 Projected 2020 demand

This study projects global demand for marine fuels to amount to 319 million metric tonnes in the base case, 14% higher in the high case and 12% lower in the base case. The drivers of overall fuel demand are transport demand and operational efficiency of ships. The base case assumes an increase in transport demand between 2012 (the model base year) and 2020 that is in line with the UNCTAD maritime transport work projection and the most recent IMF global economic growth forecast. The high case and the low case have a 8.5% higher and a 2.3% lower transport demand. The operational efficiency of the fleet is 5% worse in the high case, which has more new and efficient ships which sail slower, and 11% better in the low case, which sees ships sail considerably slower.

It is conceivable that the economy will pick up rapidly or hit another recession; transport demand will then fall outside the range considered here and ships speed up or slow down to an even greater extent, although we are not aware of any such projections. In 2007 and 2008, the amount of fuel consumed per tonne-mile was 25% higher than in the period 2009-2012, owing mainly to faster sailing ships. We consider a return to these speeds unlikely, however, because the fleet is currently much larger than in 2007 and 2008, so the increase in transport demand would need to be very large to induce ships to increase their average speeds to previous levels.

The fuel split is driven by investments in EGCSs and LNG-fuelled ships. If more ships are fitted with EGCSs or capable of sailing on LNG (and provided the prices of LNG and high-sulphur fuels are sufficiently attractive), demand for petroleum fuels with a sulphur content of 0.50% m/m or less will be lower and vice versa. Many factors affect investments in EGCSs, as was discussed in Section 4.3: their costs, relative fuel prices, cost of capital, regulatory constraints, availability and yard capacity.

It is conceivable that investments in EGCSs will be higher or lower than projected in any of the scenarios, either because assumptions pan out higher or lower than in any of our cases, or for other reasons. One factor that might be relevant in this respect is the ability of shipping companies to raise capital.

If in the coming years the Ballast Water Management Convention (BWMC) enters into force, this will require shipping companies to invest in ballast water management systems, which require a similar amount of capital as EGCSs. If market conditions for shipping companies are unfavourable in the coming years, not all the owners of the 3,000-4,000 ships projected to invest in scrubbers may be able to raise sufficient capital to do so. Such market circumstances will likely be due to low transport demand, however, thus reducing overall demand for marine fuels. On balance, the demand for fuel with a sulphur content of 0.50% m/m or less is therefore unlikely to be higher than projected.

If, on the other hand, market conditions are favourable, more companies could invest in EGCSs. Favourable market circumstances would be brought about by high demand, resulting in higher demand for fuels. If more of that demand can have a high-sulphur content, because more ships are equipped with EGCSs, it will be even higher.

Another reason for possible diversion from the projections could be that more or fewer new ships are built. For these new ships, EGCSs require lower investments because they can be incorporated in the original design. Consequently, EGCSs are more often cost-effective. If more new ships are built, demand for high-sulphur fuels would likely increase. The impact in 2020 would not be that great, however, because ships built in 2018 and 2019 make up a relatively small share of the fleet.

It is also conceivable that there will be more LNG-fuelled ships by 2020 than projected in any scenario. But even if the number of ships were to double or triple, which is more than even the most optimistic outlooks project, this would not have any major impact on demand for compliant fuels (petroleum fuels with a sulphur content of 0.50% m/m or less) because the share of LNG in the fuel mix is so low.

In summary, the base case, low case and high case are plausible estimates and demand for marine fuels in 2020 will therefore in all likelihood be within the range presented here. Still, scenarios are conceivable, but unlikely, in which demand will be either higher or lower. The main reason for demand being outside the ranges projected here would be unexpected economic developments (either a prolonged economic slowdown or unexpectedly rapid growth). Another reason could be an unexpectedly high or low investment in EGCSs, although this would have to coincide with much higher or lower transport demand to result in fuel demand lying outside the range projected by our cases. Although these possibilities cannot be ruled out entirely, it is most probable that demand in 2020 will be within the range bounded by the low case presented in this report.

6.3 Projected 2020 supply

This study shows that demand for petroleum-based marine fuels, which constitutes about 6.8% of the total demand for petroleum products in the base case in 2020, can be supplied by refineries in the base case, as well as in the high and low case. Fuel with a sulphur content of 0.10% m/m or less will be predominantly middle distillate, while fuel with a sulphur content between 0.10% and 0.50% m/m, as well as fuel with a sulphur content over 0.50% m/m, will be mostly high-viscosity fuel oil and in some cases low-viscosity fuel oil.

The main reason that the average sulphur content of marine fuels can be considerably lower by 2020 than it was in 2012 is that while global crude distillation capacity is projected to increase by 8% relative to 2012, middle distillate hydroprocessing capacity (which is used to desulphurize MGO and road diesel) is expected to increase by 17% and heavy fuel oil hydroprocessing capacity by 15%. In addition, coking and hydrocracking capacity will increase by 35% and 37%, respectively, and both processes also produce low-sulphur fuels. This allows refineries to lower the sulphur content in their products, despite a slightly higher average sulphur content and a 14% higher total amount of crude.

The maximum amount of compliant fuels that can be produced is 24% more than demand in the base case and 2% more than in the high case. In order to produce this amount, the Asian region needs crude oil with a lower sulphur content. If, on the other hand, the sulphur content of crude increases, only the Middle East has sufficient hydrotreatment capacity to produce compliant fuels in sufficient amounts.

To our knowledge new hydroprocessing units or expansions of these units always include sufficient sulphur plant capacity, although this is not supported by our data analysis for all regions. In our modelling, we have nevertheless assumed that the sulphur plant capacity will not limit the sulphur removal rates of hydroprocessing units. If this assumption is not correct, refineries will need to expand the capacity of their sulphur plants capacity to fulfill 2020 demand.

Although the assessment of refinery capacity has been conservative and, for example, only projects that are projected to be completed by June 2019 have been taken into account in this study, it is conceivable that projects are delayed or aborted, or that projects planned to be completed in or after June 2019 will come on stream early. Still, over half the expansion in middle distillate hydroprocessing capacity projected between 2012 and 2019 had already been realised by February 2016, as well as 20% of the heavy oil hydroprocessing capacity expansion. Moreover, the supply models have been run with a tighter fuel specification than required by MARPOL and the utilization rates have been limited to 90%. Hence, there is sufficient spare capacity and we do not consider this risk to be significant.

Another reason why supply could diverge from the modelling results presented here is that refineries may market new blends or intermediary streams. This occurred in 2015, for example, when several oil companies started marketing ultra-low-sulphur heavy fuel oil in ECA regions, a development that had not been foreseen by many studies and reports on the availability and prices of marine fuels published before 2015 (see e.g. (CONCAWE, 2009); (EPA, 2008) although (Purvin & Gertz, 2009) did consider this possibility). If this occurs, it is likely to increase supply and thus make it easier to meet demand for compliant fuels.

If downtime and maintenance for residual and gas oil hydrotreatment units in the second half of 2019 and the beginning of 2020 is much higher than expected, the availability of compliant fuel oil will be impacted negatively. However, maintenance can be planned well in advance, and refiners may even adopt new advanced hydroprocessing catalyst to mitigate this risk.

A faster than expected change in demand towards more ultra-low-sulphur diesel will lead to refiners producing more diesel from gas oil and will reduce the availability of low-sulphur HFO (<0.5% m/m S). Refiners can mitigate this risk by using more medium sweet crude.

Finally, a change in the crude slate, for example as a result of geopolitical tensions, may affect the availability of compliant fuels. If the resulting slate contains more high-sulphur crude, more hydrotreatment will be required to produce sufficient amounts of compliant fuels. Because of the conservative assumptions in the modelling, this need not change the conclusion. Conversely, if the crude slate is sweeter on average, more compliant fuel may be produced.

In summary, the refinery modelling indicates that a sufficient amount of fuel oil of the required quality can be produced for the base case, the low case and the high case for demand. In fact, there seems to be sufficient capacity to produce more than the high case as a result of anticipated capacity expansions, with capacity likely to increase still further after June 2019. Still, scenarios are conceivable, but unlikely, that refineries will be unable to supply a sufficient amount of compliant fuels. The main risks are that refinery expansion projects are delayed or aborted, suitable grades of crude are unavailable, demand shift towards ultra-low-sulphur diesel happens earlier than currently planned, or that refineries face capacity downsizing owing to unplanned shutdowns. Although unexpected developments cannot be ruled out, all information currently available indicates that the global refinery industry will be able to produce marine fuels in sufficient quantities in 2020.

6.4 Matching supply and demand

The previous two sections showed that a thorough analysis of the best available information indicates that a sufficient amount of marine fuels will be available in 2020 globally to comply with Regulation 14 of MARPOL Annex VI. This section analyses what could happen if unexpected developments result in a global oversupply or shortfall of marine fuels and what the impact of regional surpluses or shortages would be.

If, unexpectedly, there were to be a global shortage of marine fuel with a sulphur content between 0.10% and 0.50% m/m, this would result in an increase in the price of this type of fuel. This would have the following consequences:
- EGCSs and LNG engines will become more economically viable for a larger number of ships. More shipping companies would invest in these technologies, but because there is a considerable lead time between an investment decision and actual installation, this will not start to have an impact on demand until about a year after the price increases.
- Higher fuel prices will induce ships to slow down, thus reducing demand for fuel and mitigating the impact of the production shortfall. Speed changes cannot always be implemented instantaneously because of charter contracts and delivery schedules, but they can have an impact on demand on a shorter time scale than investments in EGCSs and LNG engines.
- As the price difference between fuel with a sulphur content of 0.50% and 0.10% becomes smaller, the latter becomes more attractive and ships may increasingly use it.
- Higher prices make blends that were previously uneconomical to market become viable alternatives, allowing fuel suppliers to increase the supply of compliant fuels.

All these actions would mitigate the impact of a global shortfall of compliant fuels.

Even though this report considers a global shortfall of the availability of marine fuels very unlikely, it expects regional shortfalls to occur, although they would be offset by surpluses in other regions. There are two ways in which this can be addressed:

– Fuels can be transported from one region to another. Since an oversupply of fuel with a sulphur content of 0.50% or less is projected in Latin America, Europe and the Middle East and a shortfall in Africa, Asia and North America, fuel may be transported from any of the former regions to any of the latter regions in order to balance regional supply and demand. This is already standard practice and will not require a change in business practices.
– Ships can change their bunkering patterns. Regions that have an oversupply of compliant fuels will most likely have lower prices than regions that need to import fuels from elsewhere. As a result, interregional shipping will bunker to a greater extent in regions where there is an oversupply of fuel. This conclusion, based on current practices, has also been demonstrated by an analysis of the spatially explicit data provided in Section A.4.

7 Fuel availability study conclusions

The overall objective of the project has been to conduct an assessment of the availability of fuel oil with a sulphur content of 0.50% m/m or less by 2020. To that end, demand for marine fuels has been modelled and a thorough analysis conducted of the ability of the refinery industry to produce the required quantities of fuel while at the same time supplying refinery products to other sectors.

The total energy demand for maritime transport is projected to increase from 11.9 EJ (2012) to 11.4-14.6 EJ as a result of transport demand growth and changes in fleet composition and technical and operational efficiency.
The base case projects energy demand to be 12.8 EJ in 2020.

Energy demand can be met by a mix of:
- petroleum fuels with a sulphur content of 0.10% m/m or less (in order to comply with Emission Control Area requirements and in engines that use MGO);
- petroleum fuels with a sulphur content between 0.10% and 0.50% m/m;
- petroleum fuels with a sulphur content of over 0.50% m/m in combination with an EGCS; and
- LNG.

Other fuels are not projected to provide any significant share of the energy consumption of the marine sector.

The consumption of LNG, both in LNG carriers that use the boil-off cargo for propulsion and in ships with LNG engines, is projected to increase from 8 million tonnes in 2012 to 11-13 million tonnes in 2020.

EGCSs are projected to be installed on ships that collectively consume 14-38 million tonnes of HFO by 2020.

The study has developed three scenarios, a base case with moderate transport demand growth, fleet renewal, LNG and EGCS uptake, a high case with higher transport demand growth and fleet renewal and lower uptake of EGCSs and LNG, so that demand for compliant petroleum fuels is larger, and a low case which is the mirror image of the high case. Table 45 shows the fuel demand in each of these cases.

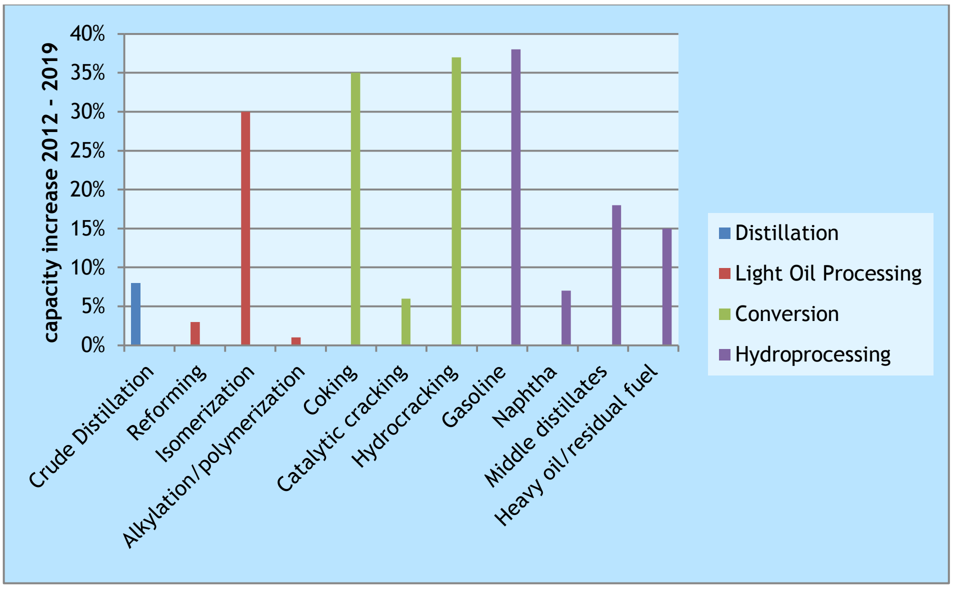
Table 45 Fuel demand projections in the base case, high case and low case

Sulphur content (% m/m)	Petroleum derived fuels			LNG
	<0.10%	0.10%-0.50%	>0.50%	
	Million tonnes per year			
Base case	39	233	36	12
High Case	48	290	14	12
Low Case	33	198	38	13

Non-marine petroleum demand will increase by 13% between 2012 and 2020 to 4,190 million tonnes per year.

Overall refinery capacity is projected to increase by 8% between 2012 and June 2019. Hydrocracking capacity will increase by 37%, middle-distillate hydroprocessing by 17% and HFO hydroprocessing by 15% (see Figure 5).

Figure 5 Refinery capacity increases 2012-June 2019



Source: Stratas Advisors, 2015-2016.

With projected refining capacity for June 2019 as an input, the refinery model was used to analyse whether sufficient amounts of compliant maritime fuels can be produced in 2020, while at the same time meeting demand for other products and not producing products for which there is insufficient demand. The model takes into account that the average sulphur content of crude oil will increase between 2012 and 2020 and that non-marine fuels will be subject to lower sulphur limits in many countries and territories.

In the base case, capacity utilization rates of Crude Distillation Units are close to 60% in all regions, while hydrocracking and hydroprocessing units have a higher utilization on average, although never higher than 83% and lower than the regional maximum observed in 2012.

The analysis demonstrates that in all cases, as well as in a number of sensitivity scenarios, the refinery sector can produce sufficient amounts of maritime fuels with a sulphur content of 0.50% m/m or less to meet demand, while at the same time producing fuels for other sectors of the required quality. The maximum amount of compliant fuels that the global refinery industry can produce is 24% above the demand projected in the base case and 2% above the demand projected in the high case.

The maritime fuels with a sulphur content between 0.10% and 0.50% m/m will typically be blends of residuals, hydrotreated residuals, heavy fractions from hydrocrackers and lighter hydrotreated fractions. The blend varies per region, depending on regional refinery capacity and crude inputs.

The viscosity of the fuels ranges from 10 cSt to 180 cSt. The maritime fuels with a sulphur content of 0.10% m/m or less will be marine gasoil.

While globally, supply and demand are balanced, regional surpluses and shortages will occur. In most cases, the Middle East has an oversupply that can be transported to other regions to offset regional shortages. In some cases, other regions have a higher production than consumption as well.

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Annex A 2012 maritime fuel demand

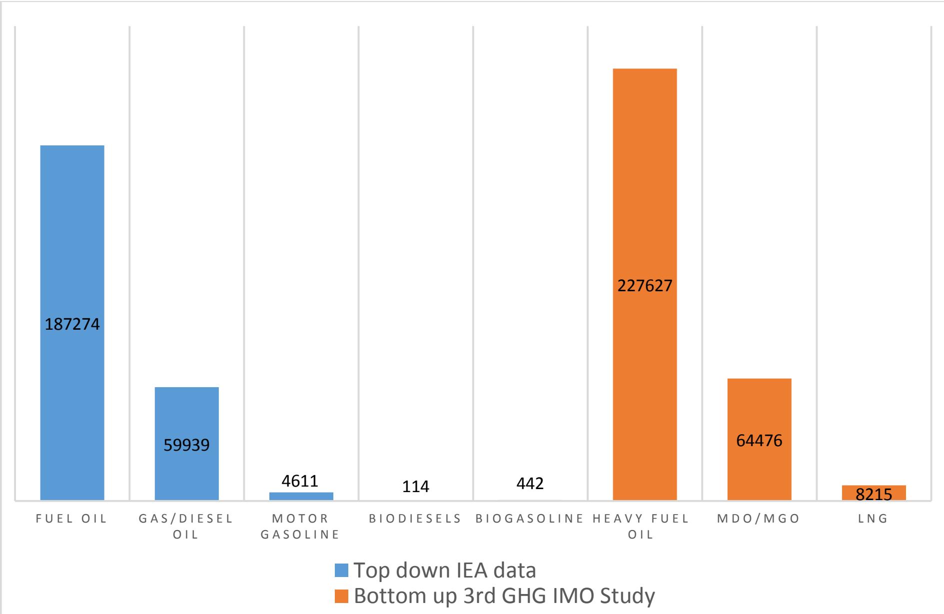
A.1 Introduction

This Annex provides additional information on the 2012 maritime fuel demand. Section A.2 presents the quality assurance of the 2012 bottom-up estimates. Section A.3 shows how the global demand was disaggregated to regions. Finally, Section A.4 provides details on where ships sail, and hence on where they are able to bunker, as a way to balance regional imbalances.

A.2 Quality assurance

At the time of the Third IMO GHG Study 2014's preparation, the top-down approach for 2012 was not possible as data were not yet available. However, the IEA dataset which the top-down method is based on has now been reported and can be analysed for comparison with the Third IMO GHG Study 2014 bottom-up calculation. The breakdown of the global 2012 fuel demands by fuel type from both approaches is shown in Figure 6. To clarify with respect to the inconsistency between the two datasets with respect to fuel taxonomy: in 2012 maritime fuels in the IEA dataset included biofuels. The bottom-up approach, includes LNG while biofuels are included in the MGO category. According to the IEA, maritime fuel sales were 252,380 million tonnes, including fuel oil (HFO), gas diesel oil (MGO), motor gasoline and biofuels for international and domestic shipping and fishing. The total gap between the two estimates is 47,938 million tonnes of fuel.

Figure 6 Global maritime fuel demands in 2012. Top-down approach (IEA datasets) and bottom-up approach (Third IMO GHG Study 2014)

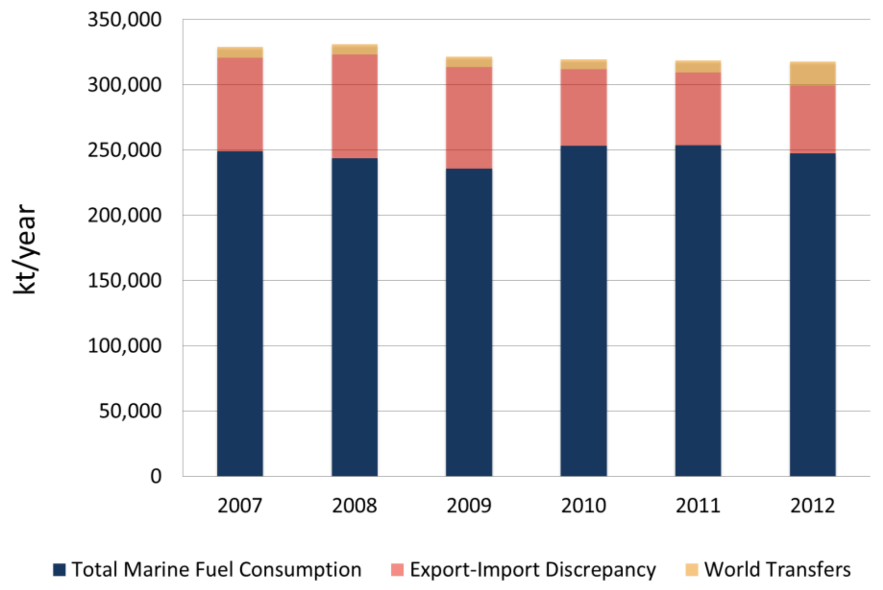


A review of literature published since the Third IMO GHG Study 2014 was undertaken and was not found to produce any further alternative perspectives or estimates. IEA energy balance statistics represent the best available

top-down data that include marine bunker fuels at global level, however they suffer from a number of uncertainties.
As discussed in Annex 4 in the Third IMO GHG Study 2014, there are at least four important sources of uncertainties:
1. Misallocation and/or duplication between international and domestic categories.
2. Misallocation with other sector (e.g. export).
3. Unreported reclassification of oil products. And
4. Data accuracy.

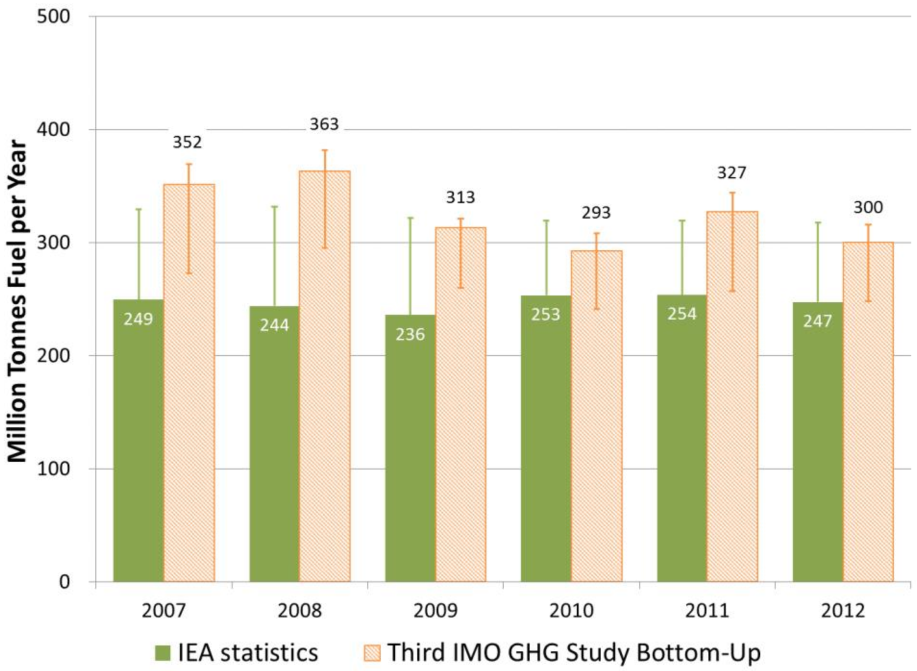
Following the same method used in the Third IMO GHG Study 2014, potential adjustments can be evaluated also for the year 2012 by considering the world energy statistical balance, and quantifying discrepancies in quantities most related to known uncertainty: export-import discrepancy and net balance of "transfers" category reporting. Export and import world balance discrepancy is used to identify an upper bound of potential correction due to a misallocation of marine fuels to "export". Instead, the net balance of transfers is used to identify a potential correction due to unreported fuel or other products that were blended for marine bunkers. In 2012, the export and import world balance discrepancy resulted in about 52 million tonnes, while the world transfers balance resulted in about 18 million tonnes. Figure 7 shows a comparison with the previous years. While export-import discrepancy slightly reduced, transfer balance increased. This analysis suggests that also for 2012 consistent uncertainty on IEA data remains, and provides a plausible explanation for the observed discrepancy between the Third IMO GHG Study 2014's bottom-up estimate and the IEA total marine fuel consumption data.

Figure 7 2007-2012 adjusted marine fuel sales based on quantitative uncertainty results



Consequently, in this study it was decided to derive the 2012 global demand from the Third IMO GHG study 2014 bottom-up estimates instead of from IEA statistics because no evidence has appeared that contradicts the Third IMO GHG Study 2014 conclusion that the former are more reliable. Figure 8 shows a summary of the uncertainty of top-down (IEA data) and bottom-up fuel inventories for all ships including 2012 IEA data. The bottom-up estimate for 2012 remains within the error bars of the top-down estimate, they remain the consensus estimate and therefore a valid starting points for the calibration of the supply model.

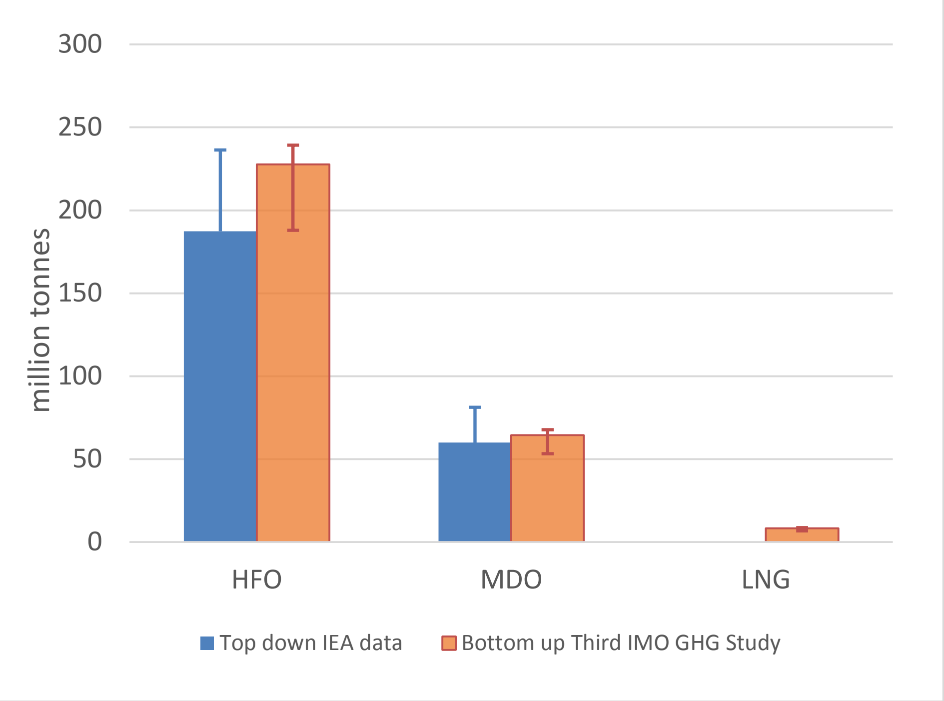
Figure 8 Updated uncertainty on IEA data (top-down) and bottom-up fuel inventories for all ships including 2012 IEA statistics



The Third IMO GHG study 2014 bottom-up estimates are also affected by uncertainty that is mainly associated with the quality control of information for specific vessels, the application of known variability in vessel activity to observed vessels within similar ship type and size fleets, and the way in which activity assumptions are applied to unobserved vessels within similar ship type and size fleets. The explicit quality control to calculate fuel use and emissions undertaken in the Third IMO GHG Study 2014 was one of the most important contributions in reducing such uncertainty. In particular, the increased coverage of the AIS data in the later year including 2012, allows for a higher accuracy of the activity estimate for individual vessels therefore a better confidence in the bottom-up estimates. The quality control of the bottom-up estimates is described in more detail in Section 1.4.3, while the complete uncertainty analysis is reported in Annex 5 of the Third IMO GHG Study 2014.

The results of the uncertainty analysis in 2012 are used in this study to define a lower and upper bound of the estimates in that year. According with the Third IMO GHG Study 2014 the lower bound corresponds to about 52 million tonnes less, while the upper bound to about 15 million tonnes more than the original estimate. Both bounds are represented in Figure 8 aggregated for all fuel types. One option to obtain lower and upper bounds per fuel type is to associate the lower and upper bounds to each fuel type proportionally to the relative fuel consumption. Figure 9 provides a summary of the top-down (IEA statistics) and the bottom- up estimates with the relative uncertainty by fuel type for the year 2012.

Figure 9 **Top-down (IEA data) and bottom-up (Third IMO GHG Study 2014) estimates in 2012 with relative lower and upper bounds by fuel type**



A.3 Regional disaggregation of fuel demand

The starting position for the regional share of maritime fuels was obtained from the IEA data on marine fuels sold in 2012 by country and aggregated by region. The first three columns of Table 46 provide the IEA shares of the global fuels sold by region. The bottom-up total maritime fuel demands from Section 3.2 were divided into regional fuel demand using these regional shares to produce the regional quantity data in the second set of columns in Table 46.

Table 46 **Starting position of regional demand for maritime fuels in 2012 and relative shares**

	HFO	MGO	LNG	HFO	MGO	LNG
	Regional share			Million tonnes		
Africa	3%	5%	7%	7.01	2.97	0.51
Asia	42%	48%	24%	99.13	30.65	1.92
CIS	4%	3%	17%	1.54	2.56	1.34
Europe	23%	23%	8%	53.95	14.45	0.64
Latin America	8%	9%	2%	19.00	5.79	0.17
Middle East	11%	2%	16%	25.52	1.05	1.29
North America	9%	11%	26%	21.62	7.01	2.04
TOTALS	100%	100%	100%	227.78	64.48	8.22

IEA has different data collection methods for IEA Member States and for others. As a result, it is possible that discrepancies in IEA statistics are larger in some regions than in others. Therefore sales statistics by region were compared with third-party sources of data, especially for regions with a low share of IEA members. In particular CIS residual regional demand appeared to be lower than other regional data describing fuel sales. Petromarket Research Group (2015) reported fuel sales in Russia that were higher than the sales reported in IEA by about 7 million tonnes. An additional source Argus (2014), reported values closer to the Petromarket estimate, as did Marine and Energy Consulting Limited (MECL, private communication). It appears that more reliable statistics are available for CIS region and consequently it was decided to use these numbers of HFO and MGO sales instead of the numbers from the IEA dataset. This adjustment implies a recalculation of the regional shares of maritime fuels and relative regional demands which correspond to the values used in this study and reported in Table 8.

A different approach was used to estimate the LNG regional shares in 2012 which takes into account that LNG was mainly used by gas carriers. The IEA datasets report that LNG was sold for shipping mainly in Europe (approximately 95%), which probably refers only to LNG as fuel market. However, the majority of LNG consumption in 2012 was consumed in the machinery of LNG carriers, which operate in different areas of the world. In the approach used in this study we used the spatially explicit data from the bottom-up method of the Third GHG IMO Study and IEA statistics of natural gas exports. We used an algorithm that first analyse in which sea areas gas carriers have consumed LNG, then associate such consumptions to regional world areas using information from the IEA dataset of natural gas exports. The resulting LNG regional shares and consumptions are provided in Table 46. Although we recognise that a number of uncertainties exist in this approach we assess such LNG regional shares in 2012 as the best available estimates.

Another complete set of regional demands and associated regional shares are available from MECL and they are reported in Table 47. For HFO, which constitutes the largest share of maritime fuel demand, the shares for the largest regions, Europe and Asia, are less than 2% apart. MECL reports a higher share for the Middle East and especially Africa, and a lower share for CIS and Latin America, than the estimate in this study.

Table 47 Regional demand and shares in 2012 from MECL

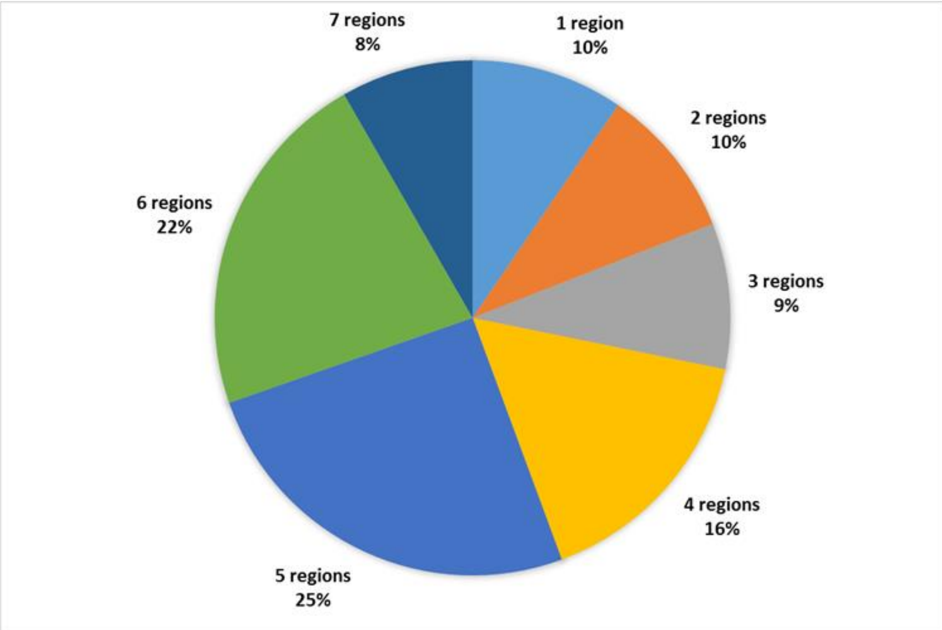
	HFO	MGO	LNG	HFO	MGO	LNG
	Regional share (%)			Million tonnes		
Africa	3.7%	6.3%	0.0%	7.54	2.80	0.00
Asia	42.7%	20.3%	0.0%	87.39	9.06	0.00
Russia & CIS	3.8%	6.2%	56.3%	7.74	2.75	0.05
Europe	23.2%	39.4%	31.3%	47.41	17.63	0.03
Latin America	7.2%	6.6%	0.0%	14.71	2.93	0.00
Middle East	11.8%	6.6%	0.0%	24.08	2.95	0.00
North America	7.7%	14.7%	12.5%	15.65	6.57	0.01
TOTALS	100%	100%	100%	204.53	44.68	0.08

Source: MECL, private communication.

A.4 Balancing regional supply and demand of compliant fuels

Even when the global supply matches global demand, regions as defined in this study could experience shortages of compliant fuels in 2020, and other regions could have an oversupply. Regional shortages of compliant fuels need not be a problem, because first of all fuels can be transported and second, many ships that trade internationally can bunker in several regions. This conclusion, based on current practices, has also been demonstrated by analysing the spatially explicit data used in the bottom-up method of the Third GHG IMO Study. We performed an analysis of this data, which enables a first attempt to assign fuel consumed in sea regions to terrestrial regions. It has been possible to allocated approximately 80% of marine fuels used in 2012. Only 10% of such amount can be allocated to a specific single region, meaning that analysing the spatial explicit data ships could have refuelled only in that region. The remaining fuel could have been bunkered from two or more regions. Figure 10 shows the share of marine fuels that has been possible to allocate to an incremental number of regions. For example, 16% of the total fuel consumptions of the year 2012 could have been refuelled in four different regions, or 25% of the total fuel consumptions could have been refuelled in five different regions. These results suggest that changing bunkering locations could balance supply and demand per region.

Figure 10 Percentages of marine fuel consumptions in 2012 apportionable to an incremental number of regions



Source: This report.

Note: The figure shows that in 2012, 25% of the fuel was consumed by ships that were active in five regions and 10% by ships that were active in just one region.

Annex B Refinery model

B.1 Introduction

Modern refineries are extremely complex and current practice of studying the refineries operation is through mathematical modelling using LP (Linear Programming) techniques, is approached for this study as well. Residual oil desulphurization is one of the several refinery processes which contribute to reducing the sulphur content in the heavy fuel oil. Flash point (for storage safety) and viscosity (to easily move through pumps and piping) are two most important parameters for the fuel oil. The refiners have considerable choice to blend components starting from middle distillate/naphtha swing to higher boiling points such as heavy residual fuel oil. However since the price of fuel oil is lower than crude, from economics point of view heavier fractions are preferred options for refineries. However for the lower sulphur requirements, refiners need to move towards lighter middle distillate maintaining the minimum flash point (60°C) and maximum viscosity limit (380 cSt or 180 cSt at 50°C) depending on low viscosity or heavier viscosity. The study is done to assess what options are available to refiners to supply the compliant marine HFO (<0.50% S), MGO, and HFO (>0.50% m/m S). The refinery model does not assess the stability or ageing of compliant marine fuels on this study. It is expected that refineries across the world will go through a product technology development process to ensure the low sulfur marine fuels perform appropriately on engines, pipelines and storage systems. Marine fuel users might receive an updated marine fuel material and safety data sheet that outlines conditions and guidelines for product handling and storage.

The projection of refinery product supply includes a detailed assessment of the global petroleum supply chain of the crude oil volume and quality attributes including biofuel, regional refinery capacity and configuration, refined product demand, refinery product fuel specifications, trade flows, demand forecast and refinery inputs and products prices.
Section B.2 provides model description and Section B.3 includes details about the regions and associated country used for refinery capacity distribution. Refinery capacity details, including fuel quality, demand and price is available in the Section B.4.

B.2 Model description

The supply model comprises a collection of refinery process sub-models, to calculate refinery production and the supply model is separated in seven regions (see Section B.3).

Each refinery model is configured to calculate the refinery inputs and production, based on product demand, product quality, capacity, configuration and processed crude oil slates. Refinery models run on AspenONE PIMS deployed on dedicated computer data processing units.

B.2.1 Model rationale

PIMS is an acronym for the Process Industry Modelling System. PIMS is a PC-based linear programming (LP) modelling system. Linear programming is a mathematical technique that can be used to optimize a set of linear equations. This technique is considered to be essential for the economic planning of many process industry facilities, particularly oil refineries. A linear program (LP) is a mathematical model of a process. The process can be a refinery, chemical plant, distribution network, or any situation with variables and constraints. Usually an LP will have more unknowns (variables) than constraints (equations).

Linear Programming (LP) is a mathematical operation, used for arriving at an optimal solution where a number of operable solutions are possible. As used in this context of this study, the technique is used to seek out the most profitable method of either building a new refinery or operating or modernizing an existing refinery.
The LP technique has been used for at least 40 years, and was the first full featured LP system designed to run on a personal computer. The system has been licensed by over 70% of oil refinery globally companies and is being used at nearly every location around the world.

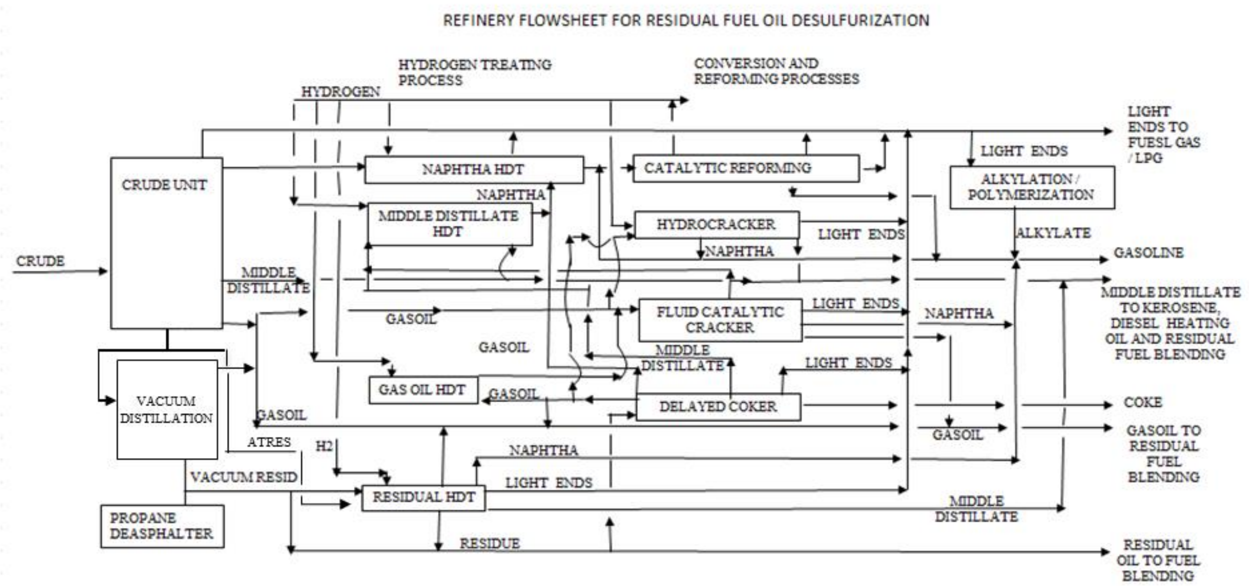
Nearly every oil refiner in the world relies on the linear programming technique for making economic decisions. The program is used for the following applications:
- grass roots refinery configuration studies;
- plant expansion studies;
- feedstock evaluations;
- product blending optimization;
- operating plan optimization;
- evaluation of alternative feedstocks;
- sizing of plant units in grass roots studies;
- optimization of product mix for a given feed slate;
- optimization of product blending and other operating decisions;
- evaluation of plant configurations;
- planning of feedstock and product inventory.

B.2.2 Refinery representation in the model

The refinery process considered on models includes most of the refinery processing units, including the following:
- atmospheric distillation;
- vacuum distillation;
- delayed coker;
- fluid coker;
- visbreaker;
- fluid catalytic cracking (FCC);
- hydrocracking;
- reformer;
- isomerization;
- hydrotreating;
- alkylation;
- polymerisation.

Figure 11 shows a refinery flow sheet for residual fuel oil desulphurization. For general discussion purpose, the flowsheet provides understanding of different units impacting the residual fuel oil desulphurization. The refinery flowsheet shows the various streams grouped together in five categories; light ends, naphtha, middle distillate, gas oil and residue. The flowsheet is arranged to emphasize the gas oil and residue being processed in various units impacts not only volume as well as quality of fuel oil. Also, the produced fuel oil is a blended product from middle distillate pool, gas oil hydrotreater, residue hydrotreater and delayed coker. Gas oil processing through conversion units such as coker, hydrocracker and FCC upgrades most of the gas oil to lighter products; also unconverted gas oil sulphur content reduces further and once blended decreases fuel oil sulphur content. In addition, improvement in capacity addition and/or catalyst technology for gas oil hydrotrater, residue hydrotreater helps reduce sulphur further down.

Figure 11 **Refinery flow sheet for residual fuel oil desulphurization**



The gas oil hydrotreater treats the gas oil feed to improve the gasoline yield. It as well treats the gas oil to reduce sulphur, reducing the fuel oil sulphur content further when used for blending. Depending on the demand and quality of gasoline, the higher quality of fuel oil production depends on the gasoline demand. Refiner's preference is to increase the gasoline production to improve the refinery margins.

The hydrocracker uses H_2 to process gas oil and produces middle distillate of better quality. A pre-treatment section before hydrocracker, (hydro-denitrification) also use H_2 to remove both sulphur and nitrogen (N_2). Here gas oil meets the demand of middle distillate and runs in multiple modes producing various products (kerosene, diesel, gasoline). The unconverted gas oil coming out from these units helps in reducing the sulphur content of fuel oil. However the refineries would be more likely using gas oil first to meet the product demand for middle distillate before letting the unconverted gas oil to blend with fuel oil due to better refinery margins.

Alternative processes such as alkylation, using light ends (propylene, butylene, iso-butanes) are as well used to convert light ends suitable for gasoline blend stock. Further use of oxygenates including ethanol also helps in meeting gasoline demand. This helps FCC to be flexible with meeting supply.

Propane De-Asphalter extracts FCCU feed from residuum by solubility in liquid propane and helps with recovering feed for FCC so that more feed is for other gas oil users.

Residual Hydrotreater is important component of achieving lower sulphur marine HFO. Resid HDS units operate in presence of a special catalyst and fairly high hydrogen partial pressure. H_2 is consumed in the process and sulphur is released as H_2S.
A sulphur plant mostly runs on Claus process and converts H_2S into sulphur. These units as are used to produce sulphur and can limit the sulphur removal if the capacity is not sufficient.

Saturated light ends are major source of H_2 production (steam reforming), in addition to H_2 produced in the catalytic reformer.

The refinery supply model schematic (Figure 11) discussed here is a simplified version of very complex processes. In order to incorporate the refining units as refinery supply model based on linear programming is used in the refinery. Similarly, here for the assessment, a supply model based on linear programming is used.

The supply model uses sub-models for each of the refinery processes. The sub-models include weight fraction yields, utility requirements, and catalyst and chemical costs. Some of the sub-models also adjust the yield structure to reflect changing feedstock properties. For example as the gas oil feed properties changes based on different crude slate, the yield and H_2 consumption changes as well.

The refinery supply model (based on Aspen PIMS) comprises a number of linked modules that are selectively executed by the user. The major source of data input to PIMS is a set of tables that describe the economics and process technology of the plant under consideration. The Matrix Generator is the cornerstone of the PIMS system. It retrieves the data in the model and automatically constructs an LP model that represents the process economics, process technology and material balance of the process.

The information in the model is input through a CASE file, which includes information about purchase, sell, fuel specifications, refinery capacity and crude quality. PIMS Optimizer reads the matrix from the file created by the Matrix Generator, optimizes the matrix (profit per barrel of crude processed in this case), and writes the optimal solution to a disk file.

Hydrogen is balanced by model considering process sub models of refinery processes that consume or produce hydrogen. Major hydrogen-consumers include hydrocracker, gasoil hydro treater, kerosene hydro treater and diesel hydro treater.

The primary source of hydrogen within a refinery is the catalytic naphtha reformer, steam methane reformer, and H_2 plants. Thus, the capacity of H_2 production is dictated by the capacity of reformer and H_2 plant.

The Claus technology is the major elemental sulphur recovering process in oil refineries. The Claus process recovers sulphur from gaseous hydrogen sulphide by-product streams originated from hydrodesulphurization units. Sulphur production capacity is reported by refiners and constrained in models accordingly.

The refinery model uses fuel specification for each region to meet the fuel demand. With the fuel specification constraint, each hydrodesulphurization process calculates the need to remove sulphur quantity from the intermediate streams. The supply model does recursion to meet the fuel specification and converges the solution once the fuel quality and supply requirements are met.

Similarly, for marine diesel oil (MGO) and heavy fuel oil (HFO), the sulphur specification of 0.10% m/m S and 0.50% m/m S and other fuel specs guide the blending of intermediate gas oil, residue oil and middle distillate streams to produce the fuel meeting the quality specification of marine fuel oil.

All grades of gasoline and diesel are modeled in the supply model to meet the respective demand in each category. For example Middle distillate pool is further divided in to ultra-low- sulphur diesel, low-sulphur diesel, high-sulphur diesel and heating oil.

B.2.3 Crude and refinery products trade flow

The supply model calculates the trade flow required between various regions. Such as Europe gasoline export to Latin America, Asia and North America, and North America diesel export to Europe and Latin America, is done through the model. Based on demand of the region, first the model is let to produce how much it can produce. And rest of the product volume is allowed to be purchased. Once the purchased amount is known, it is allocated to various regions supporting the export numbers. It is done through iterative process making sure the numbers are realistic representation of what is happening. The information from IEA, EIA, Eurostat, and OPEC are critical information considered in this step.

B.2.4 Hydrogen and sulphur balance

Catalytic reformers and steam reformers are the major sources of H_2 in a refinery. H_2 is the by-product yield from catalytic reformer when it rearranges the molecular structure to upgrade the low octane gasoline into higher octane gasoline.

The model balances the H_2 production and calculates the consumption in various hydrotreating and hydrocracking units based on feedstock being processed. The refinery supply model does a complete H_2 balance in which all the by-product sources are utilized up to their limits. The H_2 balance amount in the model will be mathematical calculated number, which in reality will may be higher or lower than what is calculated in the model.

The needed H_2 for hydroprocessing is produced in the naphtha reformer and the balance needed for Hydroprocessing comes from the hydrogen plant.
The quantity needed in 2020 is higher than in 2012. The H_2 quantity in 2020 is calculated in the model to take into account changes in crude quality and tightening of fuel specification

The H_2 plant should be within refinery because storage and transportation would require very high pressures and low temperatures. Also, a hydrogen plant should have a considerable reserve capacity for peaks.

The H_2 consumption per barrel of feed varies based on feedstock, hydrotreating & hydrocracking capacity, fuel specs, and severity of hydrotreating. As hydroprocessing progresses in severity, the H_2 demands increase. Hydrotreating severity is a function of hydroprocesing conditions (Pressure) and is constrained by H_2 availability. Increasing pressure increases H_2 partial pressure and increases the severity of hydrogenation. For example, residue hydrotreatment process requires H_2 in the order of 1,000 standard cubic feet (SCF) hydrogen per barrel of product, while the H_2 requirement of cutter stock is in the range of 100-300 SCF per barrel. Hydro treating severity is a function of the aforementioned variables and is not constrained to assumptions on the region. Further improvement in catalyst technology helps reduce the H_2 consumption per barrel of feedstock processed. The model uses H_2 consumption for different feedstock based on grade of feedstock being processed. The consumption numbers include production from naphtha reformer as well steam reformer. The capacity reported in Oil and Gas Journal data Table 92, is only steam reformer capacity. The refineries also use intermediate light ends flashed streams rich in H_2 to recycle back. Refineries uses low purity H_2 stream and recycle back to hydroprocessing. Tighter fuel specification, increased demand of products, change in crude slate and addition of more hydroprocessing capacity are the major reason for increased H_2 need. Most of the region will need more H_2 capacity than in 2012.

B.2.5 Petroleum coke sulphur content

The petroleum coke sulphur content is connected with the recent mandate in China which regulates the sulphur content in petroleum coke. The sulphur content in petroleum coke, produced in Delayer Coker varies based on the region. Africa processing of crude is light and sweet, has minimum sulphur < 1% in 2012 while it increases to 3.2% in 2020. Middle East petroleum coke sulphur content is highest at 6.8%. Rest of the region's petroleum coke sulphur content is in the range of 4-5%.

Table 48 Regional S% in petroleum coke from Delayed Coker (2020 (2012))

Regional Sulphur Percentage in petroleum coke (2020, (2012)) (1)							
Petroleum coke	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
% m/m S content	3.2% (0%)	4.5% (4.3)	4.3% (3.4%)	5.10% (4.60%)	4.20% (4.10%)	6.8% (2.7%)	4.2% (4.2%)

(1) Numbers in bracket () are 2012 numbers.

Source: Stratas Advisors, 2015-2016.

To reduce the sulphur content further in the petroleum coke, the vacuum residue will need pretreatment to bring the sulphur below 3% in petroleum coke (but this was not modelled and not discussed further in the report). The vacuum residue feedstock having sulphur content greater than 3.5% m/m is the main feedstock to the delayed coker.

B.3 Model regions

The supply model comprises a collection of refinery sub-models for different refinery unit-operations. The grouping of country in to regions provides simplification of the global supply model and ease of convenience to understand the supply. In addition calibration of 2012 model for production from various regions allows making sure that the model calculated supply is a realistic representation of the regions. There can be many variables that can impact individual refinery supply such as refinery complexity, ease of access to cheaper crude, age of refinery and technology used, and maintenance issue. But as a region the calibrated refineries supply model ensured supply in 2012 based on capacity. The calibrated model of 2012 then helps to assess the 2020 supply.

Refinery production from each region is all the global countries are grouped in the following regions:

Africa

54 countries and territories			
Algeria	Egypt	Madagascar	Senegal
Angola	Equatorial Guinea	Malawi	Seychelles
Benin	Eritrea	Mali	Sierra Leone
Botswana	Ethiopia	Mauritania	Somalia
Burkina Faso	Gabon	Mauritius	South Africa
Burundi	Gambia	Morocco	Sudan
Cameroon	Ghana	Mozambique	Swaziland
Cabo Verde	Guinea	Namibia	United Republic of Tanzania
Central African Republic	Guinea-Bissau	Niger	Togo
Chad	Kenya	Nigeria	Tunisia
Comoros	Lesotho	Democratic Republic of the Congo	Uganda
Côte d'Ivoire	Liberia	Rwanda	Western Sahara
Congo	Libya	Sao Tome and Principe	Zambia
Djibouti			Zimbabwe

Asia Pacific

39 countries and territories			
Afghanistan	Hong Kong, China	Myanmar	Singapore
Australia	India	Nepal	Solomon Islands
Bangladesh	Indonesia	New Caledonia (France)	Republic of Korea
Bhutan	Japan	New Zealand	Sri Lanka
Brunei Darussalam	Kiribati	Democratic People's Republic of Korea	Taiwan Province of China
Cambodia	Lao People's Democratic Republic	China	Thailand
Cook Islands	Macao, China	Pakistan	Tonga
Timor-Leste	Malaysia	Papua New Guinea	Vanuatu
Fiji	Maldives	Philippines	Viet Nam
French Polynesia (France)	Mongolia	Samoa	

Russia & CIS

12 countries and territories		
Armenia	Kazakhstan	Tajikistan
Azerbaijan	Kyrgyzstan	Turkmenistan
Belarus	Republic of Moldova	Ukraine
Georgia	Russian Federation	Uzbekistan

Europe

43 countries and territories			
Albania	Finland	Lithuania	San Marino
Andorra	France	Luxembourg	Serbia
Austria	Germany	the former Yugoslav Republic of Macedonia	Slovakia
Belgium	Gibraltar United Kingdom	Malta	Slovenia

43 countries and territories			
Bosnia and Herzegovina	Greece	Monaco	Spain
Bulgaria	Hungary	Montenegro	Sweden
Croatia	Iceland	Netherlands	Switzerland
Cyprus	Ireland	Norway	Turkey
Czech Republic	Italy	Poland	United Kingdom
Denmark	Latvia	Portugal	Vatican City State
Estonia	Liechtenstein	Romania	

Latin America

27 countries and territories		
Argentina	Dominican Republic	Lesser Antilles
Bahamas	Ecuador	Mexico
Belize	El Salvador	Nicaragua
Bolivia	French Guiana (France)	Panama
Brazil	Guatemala	Paraguay
Chile	Guyana	Peru
Colombia	Haiti	Suriname
Costa Rica	Honduras	Uruguay
Cuba	Jamaica	Venezuela

North America

4 countries and territories	
United States of America	Canada
Puerto Rico (United States)	U.S. Virgin Islands

Middle East

13 countries and territories	
Bahrain	Oman
Iran (Islamic Republic of)	Qatar
Iraq	Saudi Arabia
Israel	Syrian Arab Republic
Jordan	United Arab Emirates
Kuwait	Yemen
Lebanon	

B.4 Input parameters and assumptions

The following sources have been used for input parameters and assumptions:

– Historical supply and demand: based on the US Energy Information Administration (EIA); International Energy Agency (IEA); and, Statistics Canada, Manufacturing and Energy Division. Data supplemented and adjusted based on Stratas Advisors' internal data and analyses. The data includes the crude production of different quality, outlook of crude production, demand of various refinery products, prices forecast, and future fuel specifications. It also covers macro-economic factors such as GDP, population, urbanization, vehicle miles travel for various type of vehicles while provide outlook for demand model. It is important to note, the input parameters such as vehicles miles travel, GDP, population growth, and urbanisation are input parameter to the demand model, not to the supply model.
– Supply and demand projections: developed by Stratas Advisors based on EIA and IEA data, as well as internal data and previous analyses.

- Crude oil supply and quality: analysis based on EIA, CNRB (Canadian Natural Resource Board) and International Petroleum Encyclopaedia information. Data supplemented and adjusted based on Stratas Advisors' internal data and analyses.
- Crude oil purchase includes condensates as well, and natural gas (purchased gas) is bought separately in the purchase section as butanes and propane mix to represent NGLs use.
- Fuel quality, specifications and regulations: based on data from Stratas Advisors, the US Environmental Protection Agency (EPA), the National Petroleum Refiners Association (NPRA), the American Petroleum Institute (API) product quality surveys, and National Institute for Petroleum and Energy Research market surveys.
- Throughout this study, on-road diesel corresponds to the IEA's road diesel data, and off-road includes IEA's agriculture and rail transportation data.
- Biofuels, renewable fuels and alternative fuels analysis provided by Stratas Advisors.
- Refining capacities: Stratas Advisors' internal data and analyses historically based on the Oil & Gas Journal (OGJ) and Hydrocarbon Processing (HP).

B.4.1 Refinery capacity (addition, expansions and shut down)

On calibrating the 2012 base model, constrains were all about historical data. Table 49 summaries the capacity for both 2019 and 2012 for all regions.

Table 49 Regional Refinery Capacity (2012 and (June 30, 2019)) - million tonnes per year

	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS	Global[1]
Crude Distillation[2]	178 (197)	1494 (1630)	791 (723)	1,027 (1,047)	365 (484)	398 (502)	354 (437)	4,630 (5,020)
Secondary Processing Units								
Light Oil Processing								
Reforming	20 (23)	155 (163)	115.6 (105.9)	198 (186)	27.6 (29)	38.2 (58)	53 (61)	610 (626)
Isomerization	1.4 (2.8)	9.1 (13.4)	26.3 (24.3)	38 (38)	2.4 (2.4)	8.6 (22.6)	4.2 (17.8)	94 (122)
Alkylation/Polymerization	1.3 (2)	15.6 (17)	15.5 (14.3)	66 (65)	11.2 (11.2)	4.7 (5)	1.5 (3.8)	117 (118)
Conversion								
Coking	4.5 (4.4)	102.9 (132)	27.5 (33.7)	132 (159)	27.7 (45)	4.1 (23)	12.9 (23)	312 (421)
Catalytic Cracking	12 (16.6)	257 (298)	119 (111)	322.8 (309)	91.8 (91.6)	31.6 (48.6)	27.4 (41)	862 (916)
Hydrocracking	5.0 (11.3)	152.7 (177)	86.1 (102)	98 (124)	5.6 (6.59)	33.3 (54.39)	7.0 (56)	388 (532)
Hydroprocessing								
Gasoline	0.0 (0)	28.8 (49.9)	20.3 (20.6)	91.1 (96)	2.1 (6.22)	2.1 (15.5)	3.4 (15.7)	148 (204)
Naphtha	23.5 (25.5)	164.0 (163)	189.5 (175)	246.2 (272)	30.8 (47)	51.1 (68)	52 (59)	759 (810)
Middle Distillates	18.3 (26.4)	366.9 (407)	263.7 (250)	268 (305)	39.7 (49)	64.3 (140)	86 (128)	1,109 (1,306)
Heavy Oil/Residual Fuel[3]	4 (4.5)	150.8 (184)	79.4 (75)	159.8 (156)	25.2 (31.1)	23.5 (32)	19.6 (23)	439 (507)

Source: Stratas Advisors, 2015-2016. On the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

(1): The numbers in bracket () are 2020 capacity in million tonnes per year.

(2): Refers to atmospheric crude distillation and does not include vacuum crude distillation.

(3): Refers to heavy gas oil and residual fuel hydroprocessing (Refer to table 39 and glossary).

On assessing 2020 scenarios, the projected new refineries, revamps and shutdowns are the ones announced, which included the start-up year. When a start-up year is not mentioned, it is assumed that projects will not get online on June 30, 2019. The projected global refinery capacity net expansions (expansions – shutdowns) between Feb. 2016 and June 19, 2019 amounts about 6.8 million barrels per day which is in good agreement with IEA's estimated capacity expansion projections between 2015 to 2021 (7.7 million barrels per day).

The projected refinery capacity in Europe (14.5 million barrels per day) agrees with IEA's crude demand forecast in Europe by 2020. Furthermore, the projected refinery capacity in Middle East by June 2019 (10.1 million barrels per day) matches IEA's projected refinery capacity in the Middle East by 2020 (10.3 million barrels per day).

Table 50 through Table 65, show expansions and shutdowns per process per region as used in the PIMS models.

Table 50 Refining Capacity and Anticipated Expansions Europe - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	February 2016	Feb 2016-June 2019	Feb 2016-June 2019	June 2019
Crude Distillation	15.875060	14.843656	0.521241	0.200000	14.522415
Secondary Processing Units					
Light Oil Processing					
Reforming	2.320577	2.169252	0.070584	0.028000	2.126668
Isomerization	0.527882	0.507792	0.042792	0.023000	0.488000
Alkylation	0.258435	0.242480	0.003821	0.000000	0.238659
Polymerization	0.053535	0.053181	0.004500	0.000000	0.048681
Conversion					
Coking	0.552949	0.568079	0.000000	0.109000	0.677079
Catalytic Cracking	2.393482	2.276843	0.035298	0.000000	2.241545
Hydrocracking	1.730014	1.941824	0.032500	0.144200	2.053524
Hydroprocessing					
Gasoline	0.408292	0.413762	0.000000	0.000000	0.413762
Naphtha	3.805398	3.584009	0.102168	0.023700	3.505541
Middle Distillates	5.295450	5.115556	0.184082	0.094000	5.025474
Heavy Oil/Residual Fuel	1.595038	1.520638	0.000000	0.000000	1.520638
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Table 51 Major Anticipated Expansions Europe - million barrels per day

Country	Company	Crude Distillation	Vacuum Distillation	Catalytic cracking	Hydro cracker	Hydro treating	Reformer
Turkey	Socar & Turcas Refinery	0.214	0.4	0	0.066	0	0.028
Spain	Cia Espanola de Pet.	0.19	0.0305	0	0	0.01867	0
Poland	Grupa Lotos	0.09	0	0	0.004	0.05	0
Bosnia and Herzegovina	Zarubezhneft	0.045	0	0	0	0	0
Greece	Hellenic Petroleum	0.03	0.02	0	0.04	0	0
Spain	Repsol YPF	0	0	0	0.05	0	0
United Kingdom	ConocoPhillips	0	0	0	0	0.054	0

Table 52 Major Anticipated Shutdowns Europe - million barrels per day

Contry	Company	Crude distillation	Project scope
France	Total	0.153	Closure
Italy	Eni(IT)	0.11	Closure
United Kingdom	Total	0.103	Downsizing
Italy	Eni(IT)	0.084	Closure
Ireland	Phillips 66	0.071	Closure

Table 53 Refining Capacity and Anticipated Expansions Russia & CIS - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	February 2016	Feb 2016-June 2019	Feb 2016-June 2019	June 2019
Crude Distillation	7.125687	8.141497	0.086775	0.725000	8.779722
Secondary Processing Units					
Light Oil Processing					
Reforming	1.065375	1.106974	0.009858	0.136500	1.233616
Isomerization	0.085369	0.204389	0.003200	0.156200	0.357389
Alkylation	0.027461	0.058903	0.000000	0.015630	0.074533
Polymerization	0.002952	0.002952	0.000000	0.000000	0.002952
Conversion					
Coking	0.259599	0.297899	0.000000	0.163400	0.461299
Catalytic Cracking	0.550248	0.656242	0.010225	0.176200	0.822217
Hydrocracking	0.140756	0.376910	0.000000	0.757700	1.134610
Hydroprocessing					
Gasoline	0.069000	0.115800	0.000000	0.199445	0.315245
Naphtha	1.044245	1.110507	0.009500	0.091800	1.192807
Middle Distillates	1.737421	1.927543	0.019141	0.678015	2.586417
Heavy Oil/Residual Fuel	0.394481	0.394481	0.019900	0.088000	0.462581
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Table 54 Major Anticipated Expansions Russia & CIS - million barrels per day

Country	Company	Crude Distillation	Vacuum Distillation	Coker	Catalytic cracking	Hydro cracker
Russian Federation	CJSC Nizhnekmsk	0.14	0	0	0	0
Russian Federation	Mari El Refinery	0.063	0	0	0	0
Kazakhstan	Petro Kazakhstan	0.048197	0	0	0	0
Belarus	JSC	0	0.0146	0.02	0	0
Russian Federation	Lukoil	0	0	0.038318	0	0
Russian Federation	Lukoil	0	0	0	0.023721	0.001975

Table 55 Refining Capacity and Anticipated Expansions Middle East - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	February 2016	Feb 2016-June 2019	Feb 2016-June 2019	June 2019
Crude Distillation	7.996665	9.160365	0.319000	1.239500	10.080865
Secondary Processing Units					
Light Oil Processing					
Reforming	0.767297	0.930067	0.015800	0.258800	1.173067
Isomerization	0.173393	0.231193	0.000000	0.224300	0.455493
Alkylation	0.087589	0.094689	0.000000	0.000000	0.094689
Polymerization	0.007430	0.007430	0.000000	0.000000	0.007430
Conversion					
Coking	0.082200	0.311700	0.000000	0.152000	0.463700
Catalytic Cracking	0.635110	0.861447	0.000000	0.115600	0.977047
Hydrocracking	0.667991	0.945020	0.082000	0.229400	1.092420
Hydroprocessing					
Gasoline	0.042500	0.223000	0.000000	0.088000	0.311000
Naphtha	1.026045	1.034035	0.033500	0.369100	1.369635
Middle Distillates	1.290730	2.040371	0.104000	0.876800	2.813171
Heavy Oil/Residual Fuel	0.471648	0.504680	0.084000	0.230000	0.650680
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Table 56 Major Anticipated Expansions Middle East - million barrels per day

Country	Company	Crude Distillation	Coker	Catalytic cracking	Hydro cracker	Hydro treating	Reformer
Kuwait	Kuwait Nat Petroleum	0.615	0	0	0	0	0
United Arab Emirates	ConocoPhillips	0.5	0	0	0	0	0
Saudi	Aramco	0.4	0	0	0	0	0

Country	Company	Crude Distillation	Coker	Catalytic cracking	Hydro cracker	Hydro treating	Reformer
Arabia	Services Co						
Saudi Arabia	Saudi Aramco	0.4	0	0	0	0	0
Iraq	Iraqi Ministry of Oil	0.3	0	0	0	0.129	0
Qatar	Nat. Oil Distribution Co	0.25	0	0	0	0	0
Iraq	Iraq Ministry of Oil	0.2	0	0	0	0	0
United Arab Emirates	Emirates Nat. Oil Co	0	0	0.036	0	0.07	0

Table 57 Major Anticipated Shutdowns Middle East - million barrels per day

Country	Company	Crude distillation	Project scope
Kuwait	KNPC (KT)	0.2	Closure
Kuwait	KNPC (KT)	0.119	Downsizing

Table 58 Refining Capacity and Anticipated Expansions Africa - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	February 2016	Feb 2016-June 2019	Feb 2016-June 2019	June 2019
Crude Distillation	3.572964	3.441950	0.000000	0.511000	3.952950
Secondary Processing Units					
Light Oil Processing					
Reforming	0.410426	0.404151	0.000000	0.057765	0.461916
Isomerization	0.028433	0.041490	0.000000	0.015600	0.057090
Alkylation	0.019465	0.027888	0.000000	0.004700	0.032588
Polymerization	0.007214	0.006804	0.000000	0.000000	0.006804
Conversion					
Coking	0.091270	0.063510	0.000000	0.025000	0.088510
Catalytic Cracking	0.241880	0.241500	0.000000	0.092600	0.334100
Hydrocracking	0.101274	0.136274	0.000000	0.091700	0.227974
Hydroprocessing					
Gasoline	0.000000	0.000000	0.000000	0.000000	0.000000
Naphtha	0.472973	0.455203	0.000000	0.056800	0.512003
Middle Distillates	0.382082	0.451042	0.000000	0.079100	0.530142
Heavy Oil/Residual Fuel	0.081000	0.087883	0.000000	0.002400	0.090283
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Table 59 Major Anticipated Expansions Africa - million barrels per day

Country	Company	Crude Distillation	Vacuum Distillation	Catalytic cracking	Hydro treating	Reformer
Nigeria	Dangote Group	0.4	0	0	0	0
South Africa	Petro SA	0.4	0	0	0	0
Angola	Sonangol	0.2	0	0	0	0
Morocco	Int. Petroleum Investment	0	0.20145	0	0	0
Nigeria	Amakpe Int. Refineries	0.006	0	0	0.004	0.004

Table 60 Refining Capacity and Anticipated Expansions Asia Pacific - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	February 2016	Feb 2016-June 2019	Feb 2016-June 2019	June 2019
Crude Distillation	29.993722	31.004378	1.029600	2.750400	32.725178
Secondary Processing Units					
Light Oil Processing					
Reforming	3.117403	3.231181	0.029500	0.070100	3.271781
Isomerization	0.183371	0.220962	0.000000	0.048453	0.269415
Alkylation	0.298434	0.301626	0.000000	0.006900	0.308526
Polymerization	0.014269	0.035132	0.000000	0.000000	0.035132
Conversion					
Coking	2.065826	2.527126	0.028000	0.151896	2.651022
Catalytic Cracking	5.173048	5.717669	0.080000	0.342200	5.979869
Hydrocracking	3.066355	3.285244	0.066000	0.338300	3.557544
Hydroprocessing					
Gasoline	0.577605	0.909005	0.000000	0.092600	1.001605
Naphtha	3.293598	3.302501	0.037000	0.000000	3.265501
Middle Distillates	7.367198	7.943061	0.088700	0.292500	8.146861
Heavy Oil/Residual Fuel	3.157780	3.435441	0.030000	0.284455	3.689896
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Table 61 Major Anticipated Expansions Asia - million barrels per day

Country	Company	Crude Distillation	Coker	Catalytic cracking	Hydro cracker	Hydro treating	Reformer
India	Hindustan Petroleum Crom Ltd	0.361479	0	0	0	0	0
India	Indian Oil Co. Ltd	0.301233	0.074811	0	0	0	0
China	Sinopec	0.3	0	0	0	0	0
Malaysia	Petronas	0.3	0	0	0	0	0
Pakistan	Khalifa Coastal	0.25	0	0	0	0	0
China	China's Nat. Develop.	0.200822	0	0	0	0	0
China	PetroChina Co Ltd	0.200822	0	0	0	0	0

Country	Company	Crude Distillation	Coker	Catalytic cracking	Hydro cracker	Hydro treating	Reformer
Brunei Darussalam	PetroBru Sdn. Bhd.	0.2	0	0	0	0	0
China	China Nat. Petroleum	0.2	0	0	0	0	0
China	Sinopec	0.2	0	0	0	0	0
China	Sinopec	0.2	0	0	0	0	0
Viet Nam	Petro Vietnam	0.2	0	0	0	0	0
Philippines	Petro Corm	0	0.0433	0.0359	0.0157	0	0
Republic of Korea	GS Caltex	0	0	0	0	0.094	0.053
India	Indian Oil Co. Ltd	0	0.067512	0	0	0	0

Table 62 Major Anticipated Shutdowns Asia - million barrels per day

Country	Company	Crude distillation	Project scope
China	Yanshan	0.28	Closure
Taiwan Province of China	Kaohsiung	0.22	Closure
Japan	Nishihara refinery	0.1	Closure
Japan	Petrobras	0.1	Closure

Table 63 Refining capacity and Anticipated Expansions North America - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	December 2015	Jan 2016-Dec 2019	Jan 2016-June 2019	June 2019
Crude Distillation	20.63	20.18	0.00	0.86	21.03
Secondary Processing Units					
Light Oil Processing					
Reforming	3.99	3.72	0.00	0.01	3.73
Isomerization	0.76	0.77	0.00	0.00	0.77
Alkylation	1.24	1.21	0.00	0.00	1.21
Polymerization	0.10	0.09	0.00	0.00	0.09
Conversion					
Coking	2.66	2.72	0.00	0.48	3.20
Catalytic Cracking	6.48	6.19	0.00	0.01	6.20
Hydrocracking	1.97	2.43	0.00	0.05	2.49
Hydroprocessing					
Gasoline	1.83	1.94	0.00	0.00	1.94
Naphtha	4.94	5.44	0.00	0.02	5.46
Middle Distillates	5.38	6.13	0.00	0.00	6.13
Heavy Oil/Residual Fuel	3.21	3.15	0.00	0.00	3.15
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Table 64 Major Anticipated Expansions North America - million barrels per day

Country	Company	Crude Distillation	Vacuum Distillation	Coker	Catalytic cracking	Reformer	Hydro treating
Canada	Canadian Natural Resources	0.27	0	0	0	0	0
United States of America	Valero Energy Co.	0.09	0	0	0	0	0
Canada	BA Energy Inc	0.075	0	0	0	0	0
Canada	OPTI Canada Inc	0.07	0	0	0	0	0
Canada	Suncor Energy Inc	0	0	0.275	0	0	0
Canada	Canadian Natural Resources	0	0	0.1243	0	0	0
United States of America	Placid Refining Co	0.025	0	0	0.006	0.0055	0.007

Table 65 Refining Capacity and Anticipated Expansions Latin America - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	December 2015	Jan 2016-Dec 2019	Jan 2016-June 2019	June 2019
Crude Distillation	7.33	7.29	0.00	2.44	9.73
Secondary Processing Units					
Light Oil Processing					
Reforming	0.56	0.55	0.00	0.03	0.58
Isomerization	0.05	0.05	0.00	0.00	0.05
Alkylation	0.22	0.22	0.00	0.00	0.22
Polymerization	0.01	0.01	0.00	0.00	0.01
Conversion					
Coking	0.56	0.56	0.00	0.36	0.91
Catalytic Cracking	1.84	1.82	0.00	0.02	1.84
Hydrocracking	0.11	0.11	0.00	0.02	0.13
Hydroprocessing					
Gasoline	0.04	0.04	0.00	0.08	0.12
Naphtha	0.62	0.63	0.00	0.32	0.95
Middle Distillates	0.80	0.80	0.00	0.20	0.99
Heavy Oil/Residual Fuel	0.51	0.51	0.00	0.12	0.62
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

Table 66 Major Anticipated Expansions Latin America - million barrels per day

Country	Company	Crude Distillation	Vacuum Distillation	Coker	Catalytic cracking	Hydro cracking	Hydro treating
Venezuela	Petroleos de Venezuela	0.40	0	0	0	0	0
Brazil	Petroleo Brasileiro	0.30	0	0	0	0	0
Brazil	Petroleo Brasileiro	0.3	0	0	0	0	0
Ecuador	Ministry of Energy	0.3	0	0	0	0	0
Mexico	Petroleos Mexicanos	0.25	0	0.166	0	0	0
Brazil	Petrobras/PDVSA	0.23	0	0	0	0	0
Venezuela	Petroleos de Venezuela	0.2	0	0	0	0	0
Peru	Petroleos del Peru	0.028	0.029	0.02	0.019	0.02	0.052
Mexico	Petroleos Mexicanos	0.15	0.15	0	0	0	0
Brazil	Petroleo Brasileiro	0	0	0.14	0	0	0
Venezuela	Petroleos de Venezuela	0	0.14	0	0	0	0.1275

Table 67 Refining Capacity and Anticipated Expansions Global - million barrels per day

Process	Capacity	Capacity	Shutdowns	Expansion Projects	Capacity
	December 2012	February 2016	Feb 2016-June 2019	Feb 2016-June 2019	June 2019
Crude Distillation	92.516327	94.059037	1.956616	8.718977	100.821398
Secondary Processing Units					
Light Oil Processing					
Reforming	12.221360	12.112560	0.125742	0.588775	12.575593
Isomerization	1.805063	2.020271	0.045992	0.467553	2.441832
Alkylation	2.151664	2.152305	0.003821	0.027230	2.175714
Polymerization	0.189350	0.200709	0.004500	0.000000	0.196209
Conversion					
Coking	6.271861	7.044854	0.028000	1.433753	8.450607
Catalytic Cracking	17.318561	17.768667	0.125523	0.751600	18.394744
Hydrocracking	7.787498	9.231430	0.180500	1.633300	10.684230
Hydroprocessing					
Gasoline	2.969824	3.643952	0.000000	0.462545	4.106497
Naphtha	15.203806	15.559125	0.182168	0.882818	16.259775
Middle Distillates	22.252152	24.399569	0.395923	2.216201	26.219847
Heavy Oil/Residual Fuel	9.414641	9.594728	0.133900	0.723170	10.183998
Note: Volumes indicate identified expansions and assumptions made by Stratas Advisors. These might not be a full representation of all projects because of lack of available data.					

Source: Stratas Advisors, on the basis of Oil and Gas Journal Data, FuelsEurope, IEA, EIA, OPEC. Announced projects as of Dec 2015, assumed to be online on June 2019 when no start-up year is indicated.

B.4.2 Conversion factors tonnes to barrels

The conversion factors used on project are listed in Table 68.

Table 68 **Conversion factors tonnes to barrel**

	Conv factor (ton to bbl)	
	All others	OECD Europe
Gasoline	8.53	8.45
Naphtha	8.5	8.9
Jet Fuel	7.93	7.88
Kerosene	7.74	7.74
Middle Distillate	7.46	7.46
Bunkers	7.46	7.46
Heavy Fuel Oil	6.66	6.45
Bunkers	6.66	6.45
LPG	11.6	11.6
Other	7.33	7.33

1. One million barrels per day of crude oil is about 50 million tonnes per year.

B.4.3 Fuel volume demand and quality

Crude brings 1-2% m/m S, Table 31, in each regional refinery. The sulphur allowed in the product varies based on different product and region, as shown in Figure 12 for gasoline and Figure 13 for on-road diesel. The fuel specifications for non-marine refinery fuels in 2012 are indicated in Table 69.

Between 2017 and 2018, China, Georgia, Singapore, South Africa, Ukraine, and the US plan to reduce their annual average sulfur limit in gasoline to 10 ppm. Argentina, Ecuador, and Peru plan to reduce the sulfur content in on road diesel in 2016. In Europe, Bosnia & Herzegovina plans to mandate a 10 ppm cap on sulfur limit in on road diesel. In Africa, by 2016, Benin is likely to implement a sulfur reduction to 500 ppm in on road diesel. In 2016, Bahrain will be the third country in the Middle East to limit on road diesel sulfur content to 10 ppm after the United Arab Emirates and Israel. The sulphur allowed in gasoline in most of the region is 0-10 ppm, while sulphur allowed in on road diesel is 0-15 ppm in most of the region. However, certain region such as Latin America, Africa, Middle East, rural areas in various developing economies will have higher Sulphur fuel specification. A summary of the fuel specifications in 2020 is provided in Table 70. In all regions, marine fuels specs adhere to the International Standard ISO 8217 marine residual fuels categories RMG 180 and RMG 380 on sulfur % and kinematic viscosity at 50°C, and distillate marine fuels categories DMA and DMZ on sulfur % and Cetane Index.

Table 69 Fuel specs for non-marine refinery fuels (2012)

	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS	Global
Motor Gasoline (Total Pool)								
Sulphur (ppm, max)	50-1,500	10-2,000	10-150	15-30	15-2,000	10-2,000	10-500	10-2,000
Aromatics (vol%, max)	50-60	21-48	35-45	35	25-45	21-51	35-42	21-60
Benzene (vol%, max)	5	0.7-5	1-5	0.62-0.95	0.9-5.0	1-7	1-5	0.62-7
RVP at 37.8 C, (kPa)	45-90	35-93	45-100	44-107	35-90	44-79	35-100	35-107
Octane (RON+MON)/2	80-95	87-97	81-98	87-93	81-97	84-98	91-95	80-98
Middle Distillate								
On-road Diesel								
Sulphur (ppm, max)	50-10,000	10-10,000	10-350	15	10-7500	10-10,000	10-500	10-10,000
Cetane number	45-50	43-52	45-51	40-50	42-51	45-51	45-51	40-52
Off-road Diesel								
Sulphur (ppm, max)	500-10,000	2000-18,000	10-350	15-500	500-15,000	500-10,000	10-500	10-15,000

Source: Stratas Advisors, 2015-2016.

Table 70 Fuel specs for refinery fuels (Dec. 31, 2019)

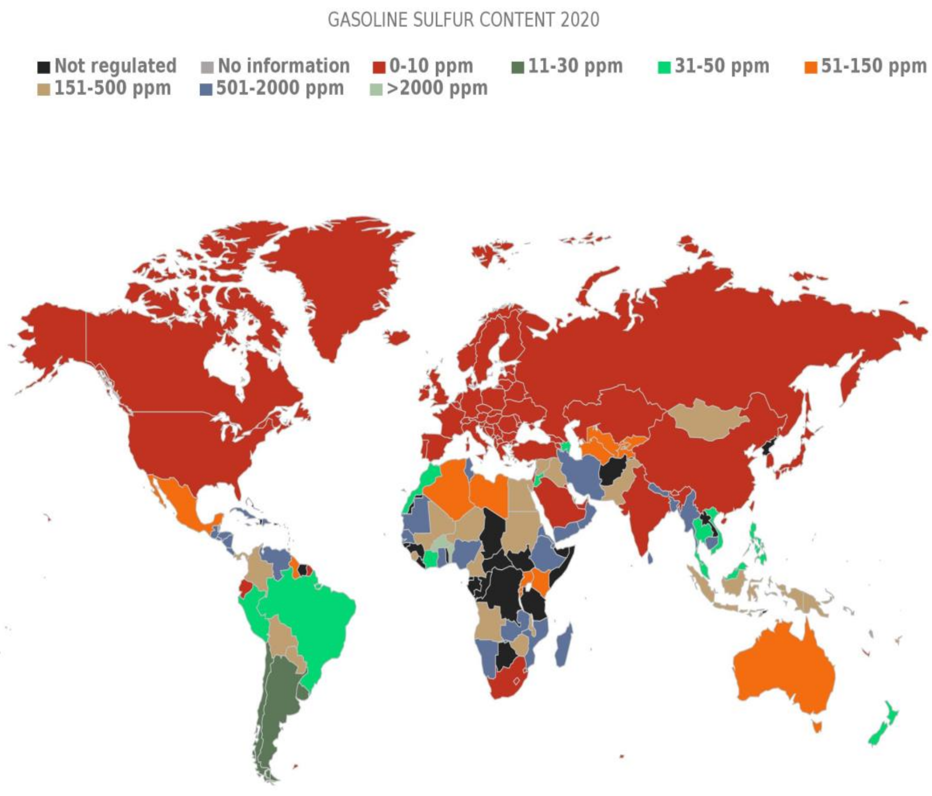
	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS	Global
Motor Gasoline (Total Pool)								
Sulphur (ppm, max)	*15*-1,500	10-*500*	*10*	*10*-30	15-2,000	10-*1,000*	10-500	10-2,000
Aromatics (vol%, max)	*35*-60	*24-50*	*35*	35	25-45	*40*	35-42	*24*-60
Benzene (vol%, max)	2-5	0.7-5	*1*	0.62-0.95	*1-3*	*1.5-4*	1-5	*0.62-5*
RVP at 37.8 C, (kPa)	45-90	*40*-93	45-100	*35*-107	35-90	44-79	35-100	35-107
Octane (RON+MON)/2	*87-96*	*84-98*	*88-90*	87-93	*79-97*	*81-97*	*78-93*	*78-98*
Middle Distillate								
On-road Diesel								
Sulphur (ppm, max)	50-10,000	10-*500*	*10*	15	10-*5,000*	10-10,000	10-*350*	10-10,000
Cetane number	45-*54*	*45*-52	*43*-51	*40*	*43*-51	*46-56*	*49*-51	40-*56*
Off-road Diesel								
Sulphur (ppm, max)	500-10,000	*10-3,500*	*10-20*	*15*	*15-5,000*	*5,000*	10-500	10-*10,000*
Marine Diesel Oil/Gas Oil								
MGO, %S m/m	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
MGO, Cetane Index (min)	40	48.5	42	42	44	40	42	40
Marine Heavy Fuel Oil (HFO)								
Low Sulphur HFO, %S m/m	≤ 0.45	≤ 0.45	≤ 0.45	≤ 0.45	≤ 0.45	≤ 0.45	≤ 0.45	≤ 0.45
Low Sulphur HFO, Viscosity@122F (cSt)	≤ 380	≤ 380	≤ 380	≤ 380	≤ 380	≤ 380	≤ 380	≤ 380
High Sulphur HFO, %S m/m	>0.50	>0.50	>0.50	>0.50	>0.50	>0.50	>0.50	>0.50
High Sulphur HFO, Viscosity@122F (cSt)	≤ 180	≤ 180	≤ 180	≤ 180	≤ 180	≤ 180	≤ 180	≤ 180

Source: Stratas Advisors, 2015-2016.

Note: Values in *italics* indicate changes since 2012.

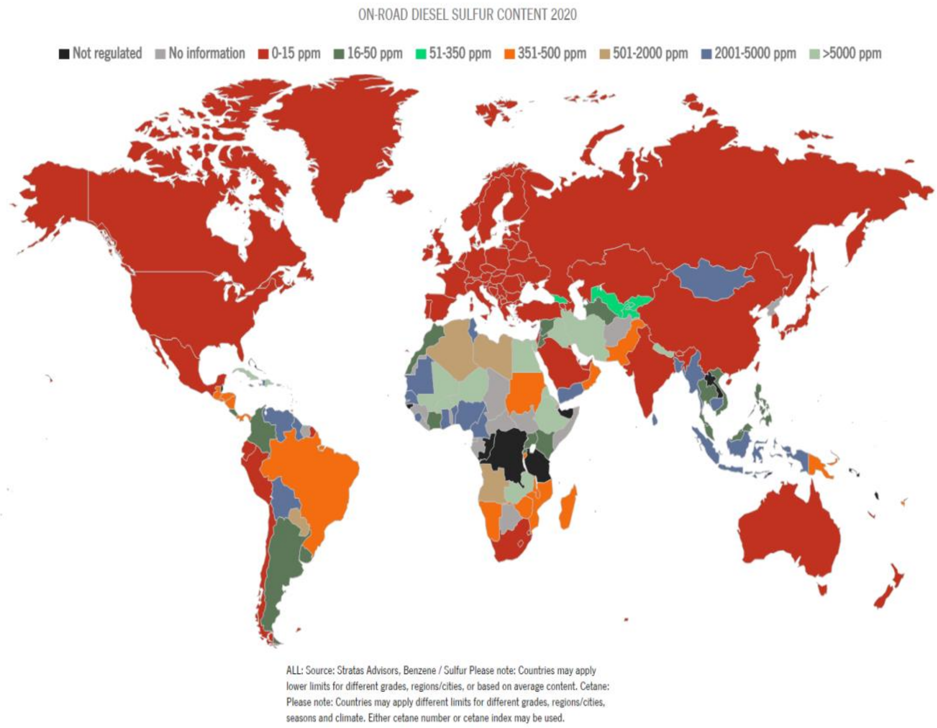
For different fuel grade the historical detailed data is available for some region such as EIA data includes historical data based on fuel grade for North America. Europe data in addition to other regional data are available through various government regulations and local database (Eurostat, OPEC). Based on the information about fuel grade in various countries and other variables such as regional vs urban fuel quality specification, Stratas Advisors forecasts for different fuel grades, which is later grouped by fuel grade for each region. Further the demand numbers are validated based on historical data and refinery capacity, which is the calibrated model for 2012. The change in government regulations and calibrated product split in 2012 is used to assess the demand for different fuel grades. In addition if the demand of higher fuel grade increases such as ultra-low-sulphur diesel (10-15 ppm), then the supply model first optimizes the refinery supply model to increase the volume first for ultra-low-sulphur diesel, as price is higher as compared to any other middle distillate product.

Figure 12 Gasoline Sulphur Content - 2020



ALL: Source: Stratas Advisors, Benzene / Sulfur Please note: Countries may apply lower limits for different grades, regions/cities, or based on average content. Cetane: Please note: Countries may apply different limits for different grades, regions/cities, seasons and climate. Either cetane number or cetane index may be used.

Figure 13 On-road diesel sulphur content



Refined product grades

The model considers refinery products of various grades. The grade types are mostly specific to various regions. Some of the grades used are as follows.

Finished Motor Gasoline

– reformulated Blended w/Fuel Oxygenates (Ethanol, MTBE);
– conventional Blended w/Fuel Oxygenates (Ethanol, MTBE);

Middle Distillate Oil

– 10 ppm sulphur and under (also called ultra-low-sulphur diesel);
– greater than 10 ppm to 30 ppm sulphur (also called ultra-low-sulphur diesel);
– greater than 30 ppm to 500 ppm sulphur (also called low-sulphur diesel);
– greater than 500 -1,000 ppm sulphur (also called high-sulphur diesel and MGO).

Heavy Fuel Oil (HFO)

– less than 0.5 % m/m sulphur;
– greater than 0.5 % m/m to 1% m/m sulphur;
– greater than 1% m/m Sulphur to 3.5% m/m sulphur.

Table 71 **Fuel grades produced on each region (Dec. 31, 2019)**

	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Motor Gasoline (Grades)							
Reformulated				X	X		
Conventional	X	X	X	X	X	X	X
Other		X		X			
Middle Distillate (Grades)							
UUSD		X	X	X		X	X
ULSD		X	X	X	X	X	
LSD	X	X	X	X	X	X	X
HSD	X	X	X	X	X	X	X
2DO	X	X	X			X	
Fuel Oil							
Low viscosity fuel oil 180	X	X	X	X	X	X	X
High viscosity fuel oil 380	X	X	X	X	X	X	X
2FO	X	X	X			X	

Source: Stratas Advisors, 2015-2016.

Biofuel ethanol blending

Biofuel ethanol blending is part of the model. Middle East does not blend ethanol into gasoline. However other regions use ethanol in gasoline. In Latin America, Brazil and Argentina are the major users. Brazil allows ethanol up to 27% based on ethanol availability. In North America, the United States allows up to 10% ethanol blends into gasoline. All EU member states are obliged to have 10% biofuels in 2020. In Asia, China, India, Indonesia, Japan, Malaysia, Philippines, Thailand and the Republic of Korea are mainly allowing the biofuel usage.

Table 72 **Refinery Input, Ethanol (2020) - million tonnes per year**

Region	Ethanol 2020
Africa	1
Asia Pacific	17
Europe	17
Latin America	38
North America	51
Middle East	0
Russia & CIS	1
TOTAL	126

Source: Stratas Advisors, 2015-2016.

B.4.4 Crude quality and volume (API and SUL) for each region

The crude slate outlook to 2020 is based on Stratas Advisors' global crude outlook, trade flow outlook to 2020 and crude oil assay database.

The crude slate on each region is comprised of an indigenous-imports pool. While indigenous production varies because natural field aging, exploration under investment, or production adjustments, refineries will always look to adjust their crude basket with crude imports and diverse crude types to increase margins and reduce dependence. This causes major shifts on global and regional crude trade flow. Just recently, India has been looking into increasing volumes of crude from Latin America, West Africa, and Canada aiming to diversify supply sources and reduce its dependence on the Middle East. US crude imports from OPEC countries have dramatically decreased in the last 5 years. Refineries will however limit the types of crudes imports to the ones they can process, resulting in smooth variations on crude slate API and SUL.

Table 31 in Section 5.4 summarizes Stratas Advisors' best estimation of the volumes and quality of crude slate processed on each region in 2020. Our best estimate is primarily constrained to crude slate API and S and the volume and type of crudes used on each region. Table 73 shows our best estimate of imports share among regions. Our best estimate, however might switch between equivalent crudes when profitability is maximized. Equivalent crude slates with similar S and API will require similar refinery capacity usage to produce a refinery product slate. Refinery balance on each region is shown in Table 74, it can be seen that total refinery input and total refinery production are in good agreement. The details for the base case are included in the Table 75 through Table 81. Unless otherwise specified, the same crude slate is used in the other cases.

Table 73 Percentage of imports share (2020, (2012)), Case 1

Crude	Africa	Asia	North America	Middle East	Europe	Russia & CIS	Latin America
Africa	0(0)	0(0)	0(11)	96.1(87.2)	0(0)	0(0)	3.9(1.8)
Asia	12.9(16.4)	0(0)	0(0.1)	69(77.5)	0.1(0.1)	14.4(1.6)	3.5(4.30)
North America	6.7(20)	0.6(0.7)	0(0)	66.4(25.5)	0.4(2.8)	0(3.6)	25.8(47.5)
Middle East	0(0)	0(0)	0(0)	0(0)	0(0)	0(0)	100(100)
Europe	20.4(23.5)	0(0)	0.8(0.2)	15.6(15.6)	0(0)	57.2(57.6)	6(3.1)
Russia & CIS	0(0)	0(0)	0(0)	0(0)	0(0)	0(0)	0(0)
Latin America	50.1(66.7)	0(1.8)	0(0.6)	49.9(22.2)	0(2)	0(6.8)	0(0)

Source: Stratas Advisors, 2015-2016.

Table 74 - Refinery balance (2020, (2012)), Case 1, 1,000 barrels per day

	Africa	Asia	North America	Middle East	Europe	Russia & CIS	Latin America
Crude	2,726 (2,165)	26,668 (24,763)	18,708 (16,613)	9,000 (6,700)	10,578 (13,285)	6,431 (6,597)	6,478 (5,715)
NGL	68 (68)	0 (0)	385 (341)	280 (300)	140 (140)	22 (22)	254 (110)
Biofuels(1)	20 (1)	75 (45)	959 (819)	1 (4)	480 (470)	39 (9)	358 (273)
Other feedstock	15 (15)	400 (151)	4,531 (6,765)	306 (286)	1,980 (1,602)	66 (121)	1,487 (1,977)
Total Input	2,829 (2,250)	27,143 (24,959)	24,583 (24,538)	9,587 (7,290)	13,178 (15,497)	6,591 (6,749)	8,576 (8,075)
Total Output	2,890 (2,293)	27,837 (25,658)	24,382 (24,903)	9,774 (7,477)	13,317 (15,705)	6,672 (6,832)	8,493 (8,146)
% Recovery	102 (101)	102 (102)	99 (101)	101 (102)	101 (101)	101 (101)	99 (100)

(1) Include Ethanol, methanol, and biodiesel.

Source: Stratas Advisors, 2015-2016.

Table 75 **Africa refinery crude inputs (2012, 2020), Case 1, million tonnes per year**

Crude	2012	2020
BRENT	8	7
GULFAKS C	8	7
CABINDA	16	22
RABI LIGHT	9	9
BONNY LIGHT	7	15
FORCADOS	7	12
ARAB LIGHT	16	15
ARAB HEAVY	9	10
BASRA LIGHT	0	10
HASSI MESSAOUD	26	27
ISTHMUS	1	1
BACHAQUERO 17	1	0
TOTAL CRUDE OIL	**108**	**136**
AVERAGE API GRAVITY	35.92	35.41
AVERAGE SULPHUR %S (m/m)	0.64	0.68

Source: Stratas Advisors, 2015-2016.

Table 76 **Asia refinery crude inputs (2012, 2020), Case 1, million tonnes per year**

Crude	2012	2020
BACHAQUERO 17	5	30
ARAB HVY	64	64
MURBAN	194	214
BASRAH	44	44
KUWAIT	38	38
ASIAN CRD BLEND (similar to Gulfaks)	184	383
CABINDA	120	75
NIG BONNY	23	27
ISTHMUS	88	30
MAYA	0	20
ARAB LT	282	328
BRENT	191	75
TOTAL CRUDE OIL	**1,233**	**1,328**
API	35.76	35.26
SUL	1.03	1.07

Source: Stratas Advisors, 2015-2016.

Table 77 **North America refinery crude inputs (2012, 2020), Case 1, million tonnes per year**

Crude	2012	2020
ALGERIA	0	2
ARAB HEAVY	46	41
BACHAQUERO	45	72
BASRHA	14	26
BETA (Canadian oil sands)	106	53
BONNY LIGHT	6	17
BRENT	0	8
CABINDA	4	8
FORCADOS	3	3
GULFAKS	0	8
HASSI/SHALE	144	177

Crude	2012	2020
HONDO	14	28
ISTHMUS	17	118
KUITO	1	2
LEONA	17	28
MARLIM	18	33
MAYA	75	127
COOK INLET	0	9
PEACE RIVER	12	48
RAINBOW	153	54
SJVH	0	27
SYNTETIC CRD	13	8
WTI	42	35
SANTA YNEZ	0	0
ALASKA N	14	0
CONDENSATE	2	0
ORIENTE	72	0
RABBI LIGHT	9	0
TOTAL CRUDE OIL	**827**	**932**
API	30.8	30.6
SUL	1.55	1.59

Source: Stratas Advisors, 2015-2016.

Table 78 Latin America refinery crude inputs (2012, 2020), Case 1 million tonnes per year

Crude	2012	2020
ARAB HEAVY	0	0
ARAB LIGHT	0	0
BACHAQUERO	35	55
BONNY LIGHT	37	71
BRENT	0	1
FORCADOS	14	14
ISTHMUS	45	45
KUITO	0	2
LEONA	51	60
MARLIM	68	38
MAYA	35	36
TOTAL CRUDE OIL	**285**	**323**
API	25.2	26.2
SUL	1.45	1.44

Source: Stratas Advisors, 2015-2016.

Table 79 Middle East refinery crude inputs (2012, 2020), Case 1, million tonnes per year

Middle East Crude Slate - barrels per day		
Crude	**2012**	**2020**
ARABIAN LIGHT	73	82
ARABIAN MEDIUM	24	27
ARABIAN HEAVY	70	115
MURBAN	19	25
KUWAIT	35	50
QATAR CONDENSATE	25	25
BASRAH	25	55
UAE	63	70
TOTAL CRUDE OIL	**334**	**448**
API	31.46	31.34
SUL	1.92	2.01

Source: Stratas Advisors, 2015-2016.

Table 80 Europe refinery crude inputs (2012, 2020), Case 1, million tonnes per year

Europe Crude Slate - barrels per day		
Crude	**2012**	**2020**
BRENT	20	18
FORTIES	20	18
GULFAKS C	208	76
ALGERIAN COND	15	8
HASSI MESSAOUD	21	12
SARIR	45	9
FORCADOS	46	76
ARAB MEDIUM	5	25
ARAB LIGHT	12	25
ARAB HEAVY	37	37
KUWAIT	0	5
CPC BLEND	47	47
URALS	185	169
TOTAL CRUDE OIL	**662**	**527**
API	35.71	34.48
SUL	0.77	1.01

Source: Stratas Advisors, 2015-2016.

Table 81 Russia & CIS refinery crude inputs (2012, 2020), Case 1, million tonnes per year

Russia & CIS Crude Slate - barrels per day		
Crude	**2012**	**2020**
CPC BLEND	23	23
URALS	305	297
TOTAL CRUDE OIL	**329**	**320**
API	32.5	32.53
SUL	1.32	1.32

Source: Stratas Advisors, 2015-2016.

Case 3: high case
As indicated in Section 5.7.3, the high demand case marine fuel demand can be met if the crude slate in the Middle East and Asia are different from the crude slate in the base case. Table 82 and Table 83 show the differences between the cases.

Table 82 Middle East refinery crude input (2020) Case 3 - million tonnes per year

Middle East Crude Slate - million tonnes per year		
Crude	**2020 High Demand, Case 3**	**2020 Base Case, Case 1**
ARABIAN LIGHT	99	82
ARABIAN MEDIUM	33	27
ARABIAN HEAVY	130	115
MURBAN	25	25
KUWAIT	35	50
QATAR CONDENSATE	30	25
BASRAH	66	55
UAE	84	70
TOTAL CRUDE OIL	**502**	**448**
API	31.43	**31.34**
SUL	1.99	**2.01**

Source: Stratas Advisors, 2015-2016.

Table 83 Asia refinery crude input (2020) Case 3 - million tonnes per year

Asia Crude Slate - million tonnes per year		
Crude	**2020 - High Demand, Case 3**	**2020 Base Case, Case 1**
BACHAQUERO 17	0	30
ARAB HVY	64	64
MURBAN	214	214
BASRAH	57	44
KUWAIT	41	38
ASIAN CRD BLEND (similar to Gulfaks)	383	383
CABINDA	82	75
NIG BONNY	30	27
ISTHMUS	30	30
MAYA	20	20
ARAB LT	360	328
BRENT	90	75
TOTAL CRUDE OIL	**1,371**	**1,328**
API	35.64	35.26
SUL	1.05	1.07

Source: Stratas Advisors, 2015-2016.

Case 4: low case

As indicated in Section 5.7.4, the low demand case marine fuel demand can be met if the crude slate in Asia is different from the base case. Table 84 shows the differences between the cases.

Table 84 Asia refinery crude inputs (2020), Case 4 - million tonnes per year

Asia Crude Slate - million tonnes per year		
Crude	**2020 Base Case**	**2020 (Low demand)**
BACHAQUERO 17	30	0
ARAB HVY	64	64
MURBAN	214	214
BASRAH	44	44
KUWAIT	38	38
ASIAN CRD BLEND (similar to Gulfaks)	383	383
CABINDA	75	62
NIG BONNY	27	27
ISTHMUS	30	30
MAYA	20	29
ARAB LT	328	328
BRENT	75	75
TOTAL CRUDE OIL	**1,328**	**1,294**
API	35.26	35.62
SUL	1.07	1.06

Source: Stratas Advisors, 2015-2016.

Case 5: maximum amount of compliant fuels

As indicated in Section 5.7.5, the supply of compliant fuels can be maximized if the crude slate in Asia and the Middle East are different from the base case. Table 85 and Table 86 show the differences between the cases.

Table 85 Asia refinery crude inputs (2020), Case 5 - million tonnes per year

Asia Crude Slate - million tonnes per year		
Crude	**2020 (Max Marine Case 5)**	**2020 Base Case - (Case 1)**
BACHAQUERO 17	0	30
ARAB HVY	64	64
MURBAN	214	214
BASRAH	57	44
KUWAIT	41	38
ASIAN CRD BLEND (similar to Gulfaks)	383	383
CABINDA	82	75
NIG BONNY	30	27
ISTHMUS	30	30
MAYA	20	20
ARAB LT	360	328
BRENT	90	75
TOTAL CRUDE OIL	**1,371**	**1,328**
API	35.64	35.26
SUL	1.05	1.07

Source: Stratas Advisors, 2015-2016.

Table 86 **Middle East refinery crude inputs (2020), Case 5 - million tonnes per year**

Middle East Crude Slate - million tonnes per year		
Crude	2020 Max Production	2020 Base Case
ARABIAN LIGHT	99	82
ARABIAN MEDIUM	33	27
ARABIAN HEAVY	130	115
MURBAN	25	25
KUWAIT	35	50
QATAR CONDENSATE	30	25
BASRAH	66	55
UAE	84	70
TOTAL CRUDE OIL	**502**	**448**
API	31.43	31.34
SUL	1.99	2.01

Source: Stratas Advisors, 2015-2016.

Case 6: high-sulphur crude
The high-sulphur case has a different crude slate for the Middle East, as indicated in Table 87.

Table 87 **Middle East refinery crude inputs (2020), Case 6 - million tonnes per year**

Crude	2020 High Sulphur	2020 Base Case
ARABIAN LIGHT	25	82
ARABIAN MEDIUM	30	27
ARABIAN HEAVY	235	115
MURBAN	23	25
KUWAIT	35	50
QATAR CONDENSATE	25	25
BASRAH	55	55
UAE	70	70
TOTAL CRUDE OIL	**498**	**448**
API	30.42	31.34
SUL	2.22	2.01

Source: Stratas Advisors, 2015-2016.

B.4.5 Crude and Refinery Products price
Stratas Advisors maintains the price data history of major refinery inputs and product prices. Stratas Advisors' in-house model is based on IBM SPSS, a time-series-based forecasting model that provides the long term and short term price outlook for the next 20 years across the oil and gas value chain.
The Short-Term Price Outlook takes an eight-quarter outlook for global prices of crude oil, natural gas, NGL refined products and more. Stratas Advisors' methodology starts by assessing historical data to identify major drivers influencing global benchmark prices. The model incorporates the drivers that factor into a variety of assumptions and potential scenarios. Stratas Advisors' model takes into account big-picture geopolitical and economic factors that can cause imbalances in underlying market fundamentals. Table 88 through Table 91 show our best estimate of crude, LNG, and petroleum products pricing in 2012 and 2020.

Table 88 Crude price in 2012 and 2020

Category	Price_code	Units	1/1/2012	1/1/2020
Crude	Brent_North West Europe	USD/bbl	111.94	76.88
Crude	WTI_North America_US	USD/bbl	94.1	73.08
Crude	Dubai_Asia_UAE	USD/bbl	108.88	75.87
Crude	ANS_North America_US	USD/bbl	110.68	76.14
Crude	LLS_North America_US	USD/bbl	111.71	76.15
Crude	HLS_North America_US	USD/bbl	112.24	75.09
Crude	WTS_North America_US	USD/bbl	88.67	69.7
Crude	Bakken_North America_US	USD/bbl	88.36	71.16
Crude	WCS_North America_Canada	USD/bbl	71.8	57.98
Crude	Maya_North America_Mexico	USD/bbl	99.6	64.35

Source: Stratas Advisors, 2015-2016.

Table 89 LNG prices in 2012 and 2020

Category	Price_code	Units	1/1/2012	1/1/2020
Natural Gas & LNG	Henry_Hub_spot	USD/MMBtu	2.75	4.11
Natural Gas & LNG	NBP_spot	USD/MMBtu	9.47	7.52
Natural Gas & LNG	Germany Border_Price	USD/MMBtu	9.49	7.73
Natural Gas & LNG	Japan_Import_Price	USD/MMBtu	16.7	10.82

Source: Stratas Advisors, 2015-2016.

Table 90 Petroleum product prices in 2012 and 2020

Price_code	Units	1/1/2012	1/1/2020
ULSD_US_North America	USD/bbl	128.21	90.85
No 2. Heating_Oil_US_North America	USD/bbl	125.45	87.33
Jet_Fuel_US_North America	USD/bbl	128.23	90.49
Gasoline_87_US_North America	USD/bbl	118	83.87
Gasoline_93_US_North America	USD/bbl	128.68	90.62
Fuel_Oil_1%_US_North America	USD/bbl	101.5	65.04
Fuel_Oil_3%_US_North America	USD/bbl	99.32	62.43
Naphtha_US_North America	USD/bbl	102.56	76.61
ULSD_North West Europe	USD/bbl	131.57	92.94
Gas_Oil 2000 ppm_North West Europe	USD/bbl	125.93	89.07
Jet_fuel_North West Europe	USD/bbl	128.54	91.34
Gasoline_95_North West Europe	USD/bbl	120.78	83.07
Gasoline_98_North West Europe	USD/bbl	126.01	88.42
Fuel_Oil_1%_North West Europe	USD/bbl	105.28	65.62
Fuel_Oil_3.5%_North West Europe	USD/bbl	96.38	59.98
Naphtha_North West Europe	USD/bbl	103.02	72.97
Gas Oil 50 ppm_Singapore_Asia	USD/bbl	128.84	93.85
Gas_Oil 500 ppm_Singapore_Asia	USD/bbl	128.18	93.11
Jet_fuel_Singapore_Asia	USD/bbl	126.78	92.03
Gasoline_92_Singapore_Asia	USD/bbl	120.4	85.71
Gasoline_95_Singapore_Asia	USD/bbl	123.43	87.85
Fuel_Oil_180cst_2%_Singapore_Asia	USD/bbl	105.37	68.44
Fuel_Oil_380cst_3.5%_Singapore_Asia	USD/bbl	103.97	67.36
Naphtha_Singapore_Asia	USD/bbl	102.83	74.82

Source: Stratas Advisors, 2015-2016.

Table 91 **Crude Price, 2012 and 2020**

Price_code	Units	1/1/2012	1/1/2020
Benchmark Crude_Brent_spot_USC_gal	USC/gal	266.52	183.05
Benchmark Crude_Brent_spot_USD_bbl	USD/bbl	111.94	76.88
Benchmark Crude_WTI_spot_USC_gal	USC/gal	224.05	174.00
Benchmark Crude_WTI_spot_USD_bbl	USD/bbl	94.10	73.08
Benchmark Crude_Dubai_spot_USC_gal	USC/gal	259.24	180.64
Benchmark Crude_Dubai_spot_USD_bbl	USD/bbl	108.88	75.87
Benchmark Natural Gas_Henry_Hub_Spot_USD_MMBtu	USD/MMBtu	2.75	4.11
Benchmark Natural Gas_Henry_Hub_Spot_USC_gal	USC/gal	37.98	56.76
Ethane_Mont_Belvieu_US_USC_gal	USC/gal	40.00	30.00
Ethane_Mont_Belvieu_US_USD_mt	USD/mt	296.80	222.60
Butane_Mont_Belvieu_US_USC_gal	USC/gal	170.00	84.00
Butane_Mont_Belvieu_US_USD_mt	USD/mt	770.10	380.52
Isobutane_Mont_Belvieu_US_USC_gal	USC/gal	180.00	88.00
Isobutane_Mont_Belvieu_US_USD_mt	USD/mt	844.20	412.72
Propane_Mont_Belvieu_US_USC_gal	USC/gal	100.00	66.00
Propane_Mont_Belvieu_US_USD_mt	USD/mt	521.00	343.86
Natural_Gasoline_Mont_Belvieu_US_USC_gal	USC/gal	225.00	137.00
Natural_Gasoline_Mont_Belvieu_US_USD_mt	USD/mt	893.25	543.89
NGL_Y-Grade_Mont_Belvieu_US_USC_gal	USC/gal	108.62	66.19
NGL_Y-Grade_Mont_Belvieu_US_USD_bbl	USD/bbl	45.64	27.81

Source: Stratas Advisors, 2015-2016.

B.4.6 Supply model 2012 calibration

The PIMS model calibration comprises a number of sub-models that are executed simultaneously. The major source of data input to PIMS is a set of tables having information such as purchase volume and price, sell volume and price, refinery products fuel specifications, and refinery process unit operation capacity. The product sell volume and purchase volume are bounded in a range (minimum and maximum) and the model calculates the supply based on constraint such as refinery process capacity, sell volume, purchase volume and fuel specifications. The calculated actual volume is then compared against the 2012 historical data for purchase and supply volume. The utilization rates of crude distillation unit and other secondary processing units such as FCC, hydrocracker and multiple hydrotreaters are important parameters for calibration.

The supply model matrix generator is the cornerstone of the LP system. It retrieves the data in the model and automatically constructs an LP model that represents the process economics, process technology and material balance of the process.

The information in the model is input through a CASE file, which includes information about purchase, sell, fuel specifications, refinery capacity, fuel specifications and crude quality. PIMS Optimizer reads the matrix from the file created by the Matrix Generator, optimizes the matrix (profit per barrel of crude processed in this case), and writes the optimal solution to a disk file.

The model is calibrated for the regional production and product quality with the known refinery input. The steps are as below:

a Production data input to the case file with minimum and maximum range to guide the solver to get a solution within the realistic range. The source of data was 2012 IEA for all the refinery products and refinery inputs. For example, production of gasoline, diesel, naphtha and consumption of crude was used; information's are available in Table 5.
b Refinery capacity and fuel specification are then updated in the model input file. Refinery capacity is mostly from O&G Journal data for Jan 01, 2013 and other sources as discussed in Table 49. And fuel specifications are based on Stratas advisor in-house information also available in Table 70.
c Additional information such as biofuel blending, import/export data for crude and refinery products, crude production including, NGLs and condensate are input into the model at this stage.
d Update the prices for the refinery products; information is available in Table 32.
e Then model run is compared against the production volume, crude inputs and its quality attributes, process unit's utilization, refinery margins. The model run results are based on the constraint on product fuel quality with known refinery capacity, configuration and crude availability with its quality attributes.

It is important to note that the refinery configuration (capacity and availability of secondary processing units) is very critical information to know. For example if the refinery is hydroskimming, then amount of crude needed to get same amount of product will be higher as compared to refinery with hydrocracker (or other conversion capacity). The calibration step helps to make sure the crude production is utilized in the model to achieve the global refinery fuel production. Having more conversion capacity will allow more gas oil and residue to be used in the refinery and will need less crude to produce similar amount of products.

The calibrated model developed for 2012 was updated with the following information for base case of 2020.

1. Regional refinery capacities were updated as detailed in Table 49 through Table 67.
2. The capacity of hydroprocessing units (hydrocracker, FCC gasoil feed hydrotreating, residue hydrocracking (HOL), and gasoil hydrotreating) were limited to 90% utilization to allow a realistic representation of the capacity utilization (90% max) in all regions.
3. The sulphur removal in hydrodesulphurization units, such as gas oil hydrotreater, residual hydrotreater and atmospheric oil hydrotreater, was limited to 90% and lower depending on the grade of oil.
4. Fuel specifications were updated for 2020, based on the information in Section B.4.3. The MGO/HFO sulphur specification was further tightened by 10%. So 0.50% S m/m HFO maximum specification was reduced to 0.45%S m/m. Similarly for MGO it was reduced to 0.09% S m/m from 0.10% S m/m. This was done to ensure the model results are robust enough to project the supply.
5. Based on 2020 demand numbers the maximum and minimum of refinery products and refinery inputs range were updated.
6. The price for 2020 was updated. Fuel oil and crude updated price is discussed in Table 32.

After making above changes the model was allowed to run for each region.

B.5 Detailed results

B.5.1 Case 1: Base case

Table 92 and Table 93 present the regional refinery H_2 consumption and sulphur production in the base case, respectively. H_2 and sulphur incremental capacity requirements in 2020 are also shown in tables (negative numbers mean idle capacity). All regions will have H_2 incremental capacity requirements ranging from about 350 to 5,000 million scfd by 2020.
While refineries always can resort to third parties for H_2 supply, that is not the case for sulfur recovery (production).

Table 92 Regional H_2 consumption and capacity (2020 (2012)), million SCFD

Regional H_2 consumption and capacity (2020 (2012))(1)			
Region	H_2 consumption (2)	H_2 production capacity (3)	H_2 incremental capacity requirements(4)
Region/Year	2020 (2012)	2020 (2012)	2020
Africa	464 (312)	113 (113)	351
Asia	7,759 (5,881)	3,663 (4,012)	4,096
Europe	4,965 (4,407)	3,214 (3,280)	1,751
North America	9,429 (7,785)	4,398 (4,582)	5,031
Latin America	1,610 (1,070)	782 (598)	828
Middle East	2,827 (1,721)	1,478 (1,548)	1,349
Russia & CIS	2,014 (953)	344 (159)	1,670

Source: Stratas Advisors, based on supply model output.
(1): Numbers in () are 2012 numbers.
(2): H_2 consumption from model output.
(3): H_2 production capacity based on Oil and Gas Journal data.
(4): H_2 consumption – H_2 production capacity.

Similar to H_2 balance the model balances the sulphur as well. The Oil and Gas Journal data report the sulphur production capacity. We have carried out a detailed match of Europe and North America sulphur capacity data which indicates they are well captured in O&G J report, however deviation in other regions indicate missing sulphur capacity data (see Table 93). Still, it is well known that most hydrotreatment units are built with more sulphur plant capacity than needed because refineries must not be constrained by their sulphur plant. Therefore we have assumed in our modelling that each new hydrotreatment and hydrocracking unit comes with sufficient sulphur production capacity to convert H_2S in elemental sulphur. If this assumption is not correct, refineries will need to expand the capacity of their sulphur plants to meet 2020 demand.

Table 93 **Regional Sulphur (2020 (2012)), tonnes per day**

Regional sulphur production and capacity			
Region	**Sulphur production (Metric tonne) - Model(2)**	**Sulphur production capacity(3)**	**S incremental capacity requirements(4)**
Region/Year	**2020 (2012)**	**2020 (2012)**	**2020**
Africa	1,168 (563)	897 (897)	271
Asia	24,680 (17,547)	22,590 (21,771)	2,090
Europe	9,276 (7,323)	16,072 (15,999)	-6,796
North America	26,266 (22,738)	37,876 (35,399)	-11,610
Latin America	4,378 (2,744)	2,840 (2,840)	1,538
Middle East	11,592 (5,733)	5,147 (5,217)	6,445
Russia & CIS	5,197 (2,983)	1,798 (1,111)	3,399

Source: Stratas Advisors, based on supply model output.
(1): Numbers in () are 2012 numbers.
(2): Sulphur production from supply model output.
(3): Sulphur plant capacity based on Oil and Gas Journal data.
(4): Sulphur production – Sulphur production capacity.

Table 94 shows as an example the sulphur balance in Russia & CIS region. About 100% of sulphur entering refineries comes from crude oil of which about 45% is recovered as elemental sulphur. About 1% of sulphur entering refineries go to marine fuels, 1% go to non-marine clean fuels, and 21% go to non-marine fuel oil. About 33% of total sulphur entering refineries go to other products.

Table 94 **Sulfur balance in Russia & CIS (2020)**

Product name	**Mass flow (mmtpy)**	**Sulphur quantity (mmtpy)**	**% Sulphur Content share**
Crude Oil	320	4.23	100%
Other Feedstock	6.14	0	0%
Total Input	326.4	4.23	100%
Fuels			
Marine fuels(1)	17.05	0.04	1%
Non marine clean Fuels(2)	206.46	0.03	1%
Non Marine Fuel Oil(3)	35.62	0.87	21%
Sulphur Production	1.9	1.9	45%
Others(4)	65.38	1.39	33%
Total Output	326.4	4.23	100%

Source: Stratas Advisors, based on supply model output.
(1) Includes MGO and marine HFO.
(2) Includes LPG, Naphtha, Gasoline, Jet, Kero, ULSD, LSD
(3) Refers to non-marine fuel oil (%S>0.5)
(4) Refers to Asphalt, Coke, lubes, Other oils and Miscellaneous products.

Table 95 through Table 101 show the blending components of HFO with a fuel content of 0.50% m/m or less for every region. The HFO blending feedstocks contributing with the highest sulfur content, are residues produced in vacuum distillation (VCRES), Visbreaker (VISBR TAR), crude distillation (ATRES), and light-high sulfur intermediate streams used to lower fuel oil viscosity (FCC Light cycle oil-CUTTER STOCK, and straight run atmospheric gasoil-SR AGO). The Sulfur content (m/m) on these blending feedstocks range from about 1.7 to 4.9%.

In all cases, marine HFO blends adhere to the International Standard ISO 8217 residual marine fuels categories RMG 180 and RMG 380 on sulfur content and kinematic viscosity at 50°C.

Table 95 Africa HFO blending (2020), barrels/day

Africa HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity cSt@50°C
CUTTER STOCK	58,108	36.32	0.127	-
ATRES	8,194	5.12	1.405	-
TR LT DIST	47,423	29.64	0.0002	-
H-OIL BTMS	46,274	28.92	1.000	-
Total	160,000	100	0.450	10

Source: Stratas Advisors, 2015-2016.

Table 96 Asia HFO blending (2020), barrels/day

Asia HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity cSt@50°C
ATRES	114,489	6.06	2.103	-
TR LT DIST	291,104	15.4	0.030	-
H-OIL BTMS	241,080	12.76	1.000	-
TRT ATRES	1,243,327	65.78	0.263	-
Total	1,890,000	100	0.450	110.7

Source: Stratas Advisors, 2015-2016.

Table 97 North America HFO blending (2020), barrels/day

North America HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity cSt@50°C
VISBR TAR	9,071	2.88	3.494	-
TRT LCO	112,060	35.63	0.107	-
LCO	11,703	3.72	0.714	-
SLURRY	45,320	14.41	0.939	-
H-OIL BTMS	40,112	12.75	1.000	-
TRT LT DIST - MED HDS	76,694	24.39	0.019	-
TR LT DIST	18,770	5.97	0.000	-
TRT KERO	649	0.21	0.065	-
TRT KERO (DSL TR)	111	0.04	0.326	-
Total	314,490	100	0.444	14.7

Source: Stratas Advisors, 2015-2016.

Table 98 Latin America HFO bending (2020), barrels/day

Latin America HFO bending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity cSt@50°C
ATRES	92,803	21.19	0.591	-
SLURRY	47,674	10.88	0.595	-
COKER/VBR HY DIST	29,559	6.75	0.591	-
IMP CUTTER	10,000	2.28	0.250	-
TRT LT DIST - MED HDS	27,943	6.38	0.012	-
TR LT DIST	214,974	49.08	0.000	-
VCRES	15,047	3.44	4.934	-
Total	438,000	100	0.450	52.1

Source: Stratas Advisors, 2015-2016.

Table 99 Middle East HFO blending (2020), barrels/day

Middle East HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity cSt@50°C
HC UCO	34,033	10.64	0.003	-
CUTTER STOCK	5,161	1.61	1.908	-
KEROSENE	3,915	1.22	0.386	-
SR AGO	3,102	0.97	1.684	-
TRT LCO TO HO	8,569	2.68	0.382	-
H-OIL HY DIST	89,943	28.11	0.197	-
H-OIL BTMS	46,998	14.69	1.000	-
TRT ATRES	128,277	40.09	0.433	-
Total	320,000	100.00	0.450	180

Table 100 Europe HFO blending (2020), barrels/day

Europe HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity cSt@50°C
SR DIESEL	224,083	23.05	0.552	-
FCC LCO	113,224	11.65	0.587	-
TR LT DIST	27,316	2.81	0.044	-
TRT AGO 85%	351,048	36.12	0.148	-
TRT PURCH GASOIL	5,404	0.56	0.015	-
H-OIL BTMS	152,943	15.73	1.000	-
TRT ATRES	97,981	10.08	0.250	-
Total	972,000	100.00	0.450	17.2

Source: Stratas Advisors, 2015-2016.

Table 101 Russia & CIS HFO blending (2020), barrels/day

Russia & CIS HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity cSt@50°C
TR LT DIST	79,286	61.94	0.037	-
H-OIL BTMS	48,714	38.06	1.000	-
Total	128,000	100	0.450	66.4

Source: Stratas Advisors, 2015-2016.

Table 102 through Table 108 show the feedstock of processing units reported in Table 6 and Table 35. It can be seen that in all regions, vacuum residue is a feedstock of H-OIL hydrocracking and Delayed coker. When Coker is not available, the vacuum residue is further processed by H-OIL hydrocracking. It is noticeable the variety of feedstock processed by hydrocracking and reforming in North America refineries, which show the high degree of conversion and other processing in US and Canadian refineries.

Table 102 Africa processing unit feedstock, Case 1 (2020), barrels/day

Processing Unit	Feedstock	Volume (barrels/day)
HYDROCRACKER	LVGO	38,747
	HOL HYDIST 650/975	33,729
	LCO	12,790
	H2 (FOE)	8,003
	Total	85,266
H-OIL	VAC RESID	120,150
	H2 (FOE)	5,972
	Total	126,122
GASOIL HDS	SR AGO TO DIESEL	18,500
	H2 (FOE)	417
	Total	18,917
DELAYED COKER	VAC RESID	85,855
	SLURRY	2,655
	Total	88,510
FCC	UNTR GASOIL TO FCC	314,100
	RESID TO FCC	30,000
	Total	344,100
REFORMER	TRT HY SRNAP 190+	326,029
	TRT HY CKRNP 190+	15,854
	TRT HY SRNAP 160+	10,539
	TRT HY HONAP 160+	11,201
	TRT HY HCNAP 160+	256
	Total	363,879
ISOMERISATION	TR LT NAPH	13,000
	H2 (FOE)	115
	Total	13,115

Table 103   Asia processing unit feedstock, Case 1 (2020), barrels/day

Processing Unit	Feedstock	Volume barrels/d
HYDROCRACKER	SR AGO	166,051
	LVGO	1,760,000
	HVGO	16,000
	HY DIST - CRACKED	16,000
	LCO	121,218
	H2 (FOE)	175,862
	Total	2,255,131
GOHDS TOTAL	UNTR GASOIL TO FCC	875,000
	H2 (FOE)	27,614
	Total	902,614
ATRES HDT	ATRES	1,365,390
	H2 (FOE)	27,062
	Total	1,392,452
H-OIL	VAC RESID	625,955
	H2 (FOE)	31,112
	Total	657,067
GASOIL HDS	SR AGO	324,185
	FCC LCO	232,825
	H2 (FOE)	8,922
	Total	565,932
DELAYED COKER	VAC RESID	1,272,569
	Total	1,272,569
FCC	UNTR GASOIL TO FCC	2,451,093
	TRT GO TO FCC -MD HD	938,281
	TRT GO TO FCC -HI H	192,104
	RESID FCC FEED	700,000
	Total	4,281,478
REFORMER	TRT HY SRNAP 190+	1,604,224
	TRT HY HONAP 190+	30,008
	TRT HY HCNAP 190+	47,800
	TRT HY SRNAP 160+	240,478
	TRT HY CKRNP 160+	138,061
	TRT HY HONAP 160+	25,755
	Total	2,086,326
ISOMERISATION	TR LT NAPH	200,449
	H2 (FOE)	1,775
	Total	202,224

Source: Stratas Advisors, 2015-2016.

Table 104   Europe processing unit feedstock, Case 1 (2020), barrels/day

Processing Unit	Feedstock	Volume (barrels/day)
HYDROCRACKER	LVGO	738,272
	HOL HYDIST 650/975	136,869
	LCO	375,060
	H2 (FOE)	119,142
	Total	1,369,343
GOHDS TOTAL	UNTR GASOIL TO FCC	685,659
	H2 (FOE)	22,017
	Total	707,676
ATRES HDT	ATRES	107,600
	H2 (FOE)	2,065
	Total	109,665

Processing Unit	Feedstock	Volume (barrels/day)
H-OIL	SDA DAO (VACRES)	1
	VAC RESID	487,560
	H2 (FOE)	24,233
	Total	511,794
GASOIL HDS	SR AGO TO DIESEL	354,204
	H2 (FOE)	7,784
	Total	361,988
DELAYED COKER	VAC RESID	299,379
	SLURRY to Other	18,400
	Total	317,779
FCC	UNTR GASOIL TO FCC	904,776
	TRT GO TO FCC -MD HD	644,219
	TRT GO TO FCC -HI H	76,339
	TRT GO TO FCC -XHI H	48,499
	RESID TO FCC	20,000
	Total	1,693,833
REFORMER	TRT HY SRNAP 190+	38,818
	TRT HY CKRNP 190+	63,372
	TRT HY HONAP 190+	41,841
	HKR HYNAPH	208,700
	TRT HYCAT LT 190+	1
	TRT HY SRNAP 160+	1,140,275
	TRT HY HCNAP 160+	14,829
	Total	1,507,836
ISOMERISATION	TR LT NAPH	300,000
	H2 (FOE)	2,768
	Total	302,768

Source: Stratas Advisors, 2015-2016.

Table 105 Middle East processing unit feedstock, Case 1 (2020), barrels/day

Processing Unit	Feedstock	Volume (barrels/day)
HYDROCRACKER	SR AGO	26,748
	HVGO	545,306
	HY DIST - CRACKED	131,724
	H2 (FOE)	69,008
	Total	772,786
GOHDS TOTAL	UNTR GASOIL TO FCC	60,000
	H2 (FOE)	2,091
	Total	62,091
ATRES HDT	ATRES	140,875
	H2 (FOE)	4,005
	Total	144,880
H-OIL	VAC RESID	320,400
	H2 (FOE)	15,925
	Total	336,325
DELAYED COKER	VAC RESID	463,700
	SLURRY	20,880
	Total	484,580
FCC	UNTR GASOIL TO FCC	806,638
	TRT GO TO FCC -MD HD	69,180
	TRT GO TO FCC -HI H	3,842
	TRT GO TO FCC -XHI H	2,194
	Total	881,854

Processing Unit	Feedstock	Volume (barrels/day)
REFORMER	TRT HY SRNAP 190+	988,894
	TRT HY SWN TO 190+	37,274
	TRT HY CKRNP 190+	72,599
	TRT HY HONAP 160+	29,869
	TRT HY HCNAP 160+	5,219
	Total	1,133,855
ISOMERISATION	Natural Gasoline	46,870
	H2 (FOE)	432
	Total	47,303

Source: Stratas Advisors, 2015-2016.

Table 106 Russia & CIS processing unit feedstock, Case 1 (2020), barrels/day

Processing Unit	Feedstock	Volume (barrels/day)
HYDROCRACKER	LVGO	17,0706
	HVGO	15,1947
	HOL HYDIST 650/975	235
	LCO	56,980
	H2 (FOE)	36,202
	Total	416,070
GOHDS TOTAL	UNTR GASOIL TO FCC	272,516
	H2 (FOE)	8,689
	Total	281,205
H-OIL	VAC RESID	200,000
	H2 (FOE)	9,941
	Total	209,941
DELAYED COKER	VAC RESID	135,000
	SLURRY to Other	15,000
	Total	150,000
FCC	UNTR GASOIL TO FCC	354,512
	TRT GO TO FCC -MD HD	302,795
	TRT GO TO FCC -HI H	45,966
	Total	703,273
REFORMER	TRT HY SRNAP 190+	365,741
	TRT HY HONAP 190+	17,163
	TRT HY HCNAP 190+	5,673
	HKR HYNAPH	30,236
	TRT HY SRNAP 160+	264,556
	TRT HY CKRNP 160+	62,143
	Total	683,369
ISOMERISATION	TR LT NAPH	50,000
	H2 (FOE)	442
	Total	50,442

Source: Stratas Advisors, 2015-2016.

Table 107 Latin America processing unit feedstock, Case 1 (2020), barrels/day

Processing Unit	Feedstock	Volume (barrels/day)
HYDROCRACKER	LVGO	101,286
	HVGO	1
	LCO	17,874
	H2 (FOE)	11,764
	Total	130,925
GOHDS	UNTR GASOIL TO FCC	344,423
	H2 (FOE)	11,827
	Total	356,250
GASOIL HDS	SR AGO TO DIESEL	142,893
	H2 (FOE)	3,626
	Total	146,519
DELAYED COKER	VAC RESID	485,737
	Total	485,737
FCC	UNTR GASOIL TO FCC	910,351
	TRT GO TO FCC -MD HD	354,257
	TRT GO TO FCC -HI H	5,799
	RESID TO FCC	90,999
	Total	1,361,406
REFORMER	TRT HY SRNAP 190+	175,976
	TRT HY CKRNP 190+	40,914
	TRT HY HCNAP 190+	4,697
	TRT LTCAT BTMS	30,511
	TRT HY SRNAP 160+	394,275
	TRT HY HCNAP 160+	6,591
	TRT HY CKRNP 160+	20,151
	Total	673,115
ISOMERIZATION	LIGHT NAPH TOP SALES	18,003
	H2 (FOE)	163
	Total	18,166

Source: Stratas Advisors, 2015-2016.

Table 108 North America processing unit feedstock, Case 1 (2020), barrels/day

Processing Unit	Feedstock	Volume (barrels/day)
HYDROCRACKER	SR DIESEL	12,485
	LVGO	1,020,225
	HVGO	250,684
	HY DIST - FLCKR	56,116
	LCO	491,521
	LCGO	28,013
	VISBR LT DIST	2,941
	HY DIST - DLC	64,372
	VISBR HY DIST	2,824
	HOL HYDIST 650/975	752
	HY DIST - CRACKED	40,126
	H2 (FOE)	212,350
	Total	2,182,409
GOHDS	UNTR GASOIL TO FCC	2,393,223
	H2 (FOE)	80,671
	Total	2,473,894
ATRES HDT	ATRES	37,000
	H2 (FOE)	1,014
	Total	38,014

Processing Unit	Feedstock	Volume (barrels/day)
H-OIL	VAC RESID	167,894
	H2 (FOE)	8,345
	Total	176,239
GASOIL HDS	SR AGO TO DIESEL	44,284
	LCO	199,966
	H2 (FOE)	6,293
	Total	250,543
DELAYED COKER	VAC RESID	2,261,948
	SLURRY	129,294
	Total	2,391,242
FCC	UNTR GASOIL TO FCC	2,632,111
	TRT GO TO FCC -MD HD	699,749
	TRT GO TO FCC -HI H	1,704,941
	TRT GO TO FCC -XHI H	48,498
	RESID TO FCC	860,701
	Total	5,946,000
REFORMER	TRT HY SRNAP 190+	1,488,153
	TRT HY HONAP 190+	14,408
	TRT HY HCNAP 190+	166,411
	TRT HY CKRNP 190+	317,318
	HKR HYNAPH	409,372
	TRT HY SRNAP 160+	959,686
	TRT HY CKRNP 160+	2,770
	TRT HY HCNAP 160+	2,099
	TRT HY CKRNP 160+	2,770
	TRT LTCAT BTMS	350,194
	TRT HYCAT LT 160+	62,499
	Total	3,775,680
ISOMERIZATION	LIGHT NAPH TOP SALES	766,539
	H2 (FOE)	6,958
	Total	773,497

Source: Stratas Advisors, 2015-2016.

B.5.2 Case 2: Low flash point

Table 109 through Table 115 show the blending components of HFO with a fuel content of 0.50% m/m or less for every region in case marine fuels are required to have a flashpoint of 52°C or higher instead of the current limit of 60°C or higher.

Table 109 Africa HFO blending, Case 2 (2020), barrels/day

Africa HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
CUTTER STOCK	58,108	36.32	0.127	-
ATRES	8,194	5.12	1.405	-
TR LT DIST	47,423	29.64	0.0002	-
H-OIL BTMS	46,274	28.92	1.000	-
Total	160,000	100	0.450	10

Source: Stratas Advisors, 2015-2016.

Table 110 Asia HFO blending Case 2 (2020), barrels/day

Asia HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
ATRES	114,489	6.06	2.103	-
TR LT DIST	291,104	15.4	0.030	-
H-OIL BTMS	241,080	12.76	1.000	-
TRT ATRES	1,243,327	65.78	0.263	-
Total	1,890,000	100	0.450	111

Source: Stratas Advisors, 2015-2016.

Table 111 North America HFO blending Case 2 (2020), barrels/day

North America HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
VISBR TAR	9,071	2.88	3.494	-
TRT LCO	112,060	35.63	0.107	-
LCO	11,703	3.72	0.714	-
SLURRY	45,320	14.41	0.939	-
H-OIL BTMS	40,112	12.75	1.000	-
TRT LT DIST -MED HDS	76,694	24.39	0.019	-
TR LT DIST	18,770	5.97	0.000	-
TRT KERO	649	0.21	0.065	-
TRT KERO (DSL TR)	111	0.04	0.326	-
Total	314,490	100	0.444	10

Source: Stratas Advisors, 2015-2016.

Table 112 Latin America HFO blending Case 2 (2020), barrels/day

Latin America HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
ATRES	92,803	21.19	0.591	-
SLURRY	47,674	10.88	0.595	-
COKER/VBR HY DIST	29,559	6.75	0.591	-
IMP CUTTER	10,000	2.28	0.250	-
TRT LT DIST -MED HDS	27,943	6.38	0.012	-
TR LT DIST	214,974	49.08	0.000	-
VCRES	15,047	3.44	4.934	-
Total	438,000	100	0.450	37

Source: Stratas Advisors, 2015-2016.

Table 113 Middle East HFO blending Case 2 (2020), barrels/day

Middle East HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
HC UCO	34,033	10.64	0.003	-
CUTTER STOCK	5,161	1.61	1.908	-
KEROSENE	3,915	1.22	0.386	-
SR AGO	3,102	0.97	1.684	-
TRT LCO TO HO	8,569	2.68	0.382	-
H-OIL HY DIST	89,943	28.11	0.197	-
H-OIL BTMS	46,998	14.69	1.000	-
TRT ATRES	128,277	40.09	0.433	-
Total	320,000	100.00	0.450	180

Source: Stratas Advisors, 2015-2016.

Table 114 Europe HFO blending Case 2 (2020), barrels/day

Europe HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
SR DIESEL	224,083	23.05	0.552	-
FCC LCO	113,224	11.65	0.587	-
TR LT DIST	27,316	2.81	0.044	-
TRT AGO 85%	351,048	36.12	0.148	-
TRT PURCH GASOIL	5,404	0.56	0.015	-
H-OIL BTMS	152,943	15.73	1.000	-
TRT ATRES	97,981	10.08	0.250	-
Total	972,000	100.00	0.450	17.2

Source: Stratas Advisors, 2015-2016.

Table 115 Russia & CIS HFO blending Case 2 (2020), barrels/day

Russia & CIS HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
TR LT DIST	79,286	61.94	0.037	-
H-OIL BTMS	48,714	38.06	1.000	-
Total	128,000	100	0.450	66

Source: Stratas Advisors, 2015-2016.

B.5.3 Case 3: High case

As indicated in Section 5.7.3 would the Middle East supply other regions with HFO with a sulphur content of 0.50% m/m or less in the high demand case. Table 116 shows which regions will import HFO from the Middle East.

Table 116 Global marine fuel trade flow (2020), high case (Case 3) - million tonnes per year

Trade Flow HFO (S<0.50%) From/To	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Middle East	5	0	12	15	2	0	2

Source: Stratas Advisors, 2015-2016.

Table 117 and Table 118 present the regional refinery H_2 consumption and sulphur production in the high case, respectively.

Table 117 H_2 consumption Asia and Middle East (2020) high case - MMSCFD

Regional H_2 consumption & production capacity (2020)		
Region	**H_2 consumption (MMSCFD) (1)**	**H_2 production capacity (2)**
Region/Year	**2020**	**2020**
Asia	8,238 (7,759)	3,663
Middle East	2,889 (2,827)	1,478

Source: Stratas Advisors, 2015-2016.

(1) Consumption numbers in bracket () are 2020 base case (Case 1) numbers.

(2) H_2 production capacity based in Oil and Gas Journal data.

Table 118 Sulphur production Asia and Middle East (2020) high case - tonnes per day

Regional sulphur production and capacity		
Region/Year	**Sulphur production (Metric tonne) - Model[1]**	**Sulphur production capacity OGJ [2]**
	2020 (Case 1)	**2020**
Asia	24,851 (24,680)	22,590
Middle East	11,969 (11,592)	5,147

Source: Stratas Advisors, 2015-2016.

(1) Production numbers in bracket () are 2020 base case (Case 1) numbers.

(2) Sulphur plant capacity based on Oil and Gas Journal data.

In the high case, the utilization rates of most desulphurisation and conversion units will be higher than in the base case, as shown in Table 119. As in all other cases, utilization rates are capped at 90% in order to allow for planned and unplanned downtime.

Table 119 % Capacity utilization Asia and Middle East (2020) high case

PROCESS	Asia East Base Case - Case 1	Asia High Case - Case 3	Middle East Base Case - Case 1	Middle East High Case - Case 3
CDU	68%	70%	74%	83%
HYDROCRACKER	76%	83%	83%	83%
GOHDS TOTAL	83%	83%	83%	83%
ATRES HDT	83%	83%	46%	83%
H-OIL	83%	83%	83%	83%
GASOIL HDS	51%	31%	0%	0%
AGO HDS	30%	30%	73%	72%
LCO HDS	22%	1%	2%	0%
DELAYED COKER	48%	52%	83%	83%

Source: Stratas Advisors, 2015-2016.

Table 120 and Table 121 show how HFO with a sulphur content of 0.50% m/m or less is blended in the high demand case in Asia and the Middle East, respectively.

Table 120 HFO (<0.5 % m/m S) Asia (2020) high case

Asia HFO blending (2020)								
Component to Blend	High case - Case 3				Base case - Case 1			
	Volume (barrels/ day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)	Volume (barrels/ day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
ATRES	203,627	8.22	2.088	-	114,489	6.06	2.103	-
SR AGO	63,281	2.55	1.037	-	0	0	-	-
TR LT DIST	725,685	29.3	0.011	-	291,104	15.4	0.03	-
H-OIL BTMS	241,080	9.73	1	-	241,080	12.76	1	-
TRT ATRES	1,243,328	50.19	0.261	-	1,243,327	65.78	0.263	-
Total	2,477,000	100	0.45	41	1,890,000	100	0.045	110

Source: Stratas Advisors, 2015-2016.

Table 121 HFO (<0.5 % m/m S) Middle East (2020) high case

Middle East HFO blending (2020)								
Component to Blend	High case - Case 3				Base case - Case 1			
	Volume (barrels/ day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)	Volume (barrels/ day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
HC UCO	31,615	4.12	0.003	-	34,033	10.64	0.003	-
CUTTER STOCK	0	0	-	-	5,161	1.61	1.908	-
KEROSENE	161,863	21.08	0.371	-	3,915	1.22	0.386	-
SR AGO	0	0	-	-	3,102	0.97	1.684	-
TRT AGO TO HO	130,076	16.94	0.249	-	0	0	-	-
TRT LCO TO HO	0	0	-	-	8,569	2.68	0.382	-
H-OIL HY DIST	89,943	11.71	0.197	-	89,943	28.11	0.197	-
H-OIL BTMS	123,399	16.07	1	-	46,998	14.69	1	-
TRT ATRES	231,104	30.09	0.43	-	128,277	40.09	0.433	-
Total	768,000	100	0.45	39	320,000	100	0.45	180

Source: Stratas Advisors, 2015-2016.

B.5.4 Case 4: Low case

Table 122 presents the projected trade flows of HFO with a sulphur content of 0.50% m/m or less in the low demand case.

Table 122 Global marine fuel trade flow (2020), low case (Case 4) - million tonnes per year

Trade Flow HFO (S<0.50%) From/To	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
Middle East	1	13					
Europe		9					
Latin America		1		5			
Russia & CIS		1			2	0	2

Source: Stratas Advisors, 2015-2016.

Table 123 and Table 124 present the regional refinery H_2 consumption and sulphur production in the low demand case, respectively.

Table 123 H_2 consumption in Asia - Low case (Case 4) (2020)

PROCESS 2020 H_2 consumption - (MMSCFD)	Asia, 2020 Low Case, Case 4	Asia, 2020 Base Case, Case 1
Asia	7,787	7,759

Source: Stratas Advisors, 2015-2016.

Table 124 Sulphur production Asia - low case (Case 4) (2020)

PROCESS 2020 Sulphur Production - (tonnes)	Asia, 2020 Low Case, Case 4	Asia, 2020 Base Case, Case 1
Asia	24,650	24,680

Source: Stratas Advisors, 2015-2016.

Refinery desulphurization capacity utilization and conversion in Asia in the low demand case is shown in Table 125.

Table 125 % Capacity utilization Asia - low case (Case 4), (2020)

PROCESS 2020 capacity utilization	Asia, 2020 Low Case, Case 4	Asia, 2020 Base Case, Case 1
CDU	66%	68%
HYDROCRACKER	76%	76%
GOHDS TOTAL	83%	83%
ATRES HDT	83%	83%
H-OIL	83%	83%
GASOIL HDS	83%	51%
AGO HDS	50%	30%
LCO HDS	33%	22%
DELAYED COKER	57%	48%

Source: Stratas Advisors, 2015-2016.

Table 126 shows how HFO with a sulphur content of 0.50% m/m or less is blended in the low demand case in Asia.

Table 126 HFO (<0.50% m/m S) blending - low case (2020)

Asia HFO blending (2020) Low case (Case 4)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
SLURRY	10,915	0.86	2.1817	-
ATRES	26,275	2.07	2.1167	-
NAP/KERO SWING	117,593	9.25	0.0627	-
H-OIL BTMS	220,567	17.35	1	-
TRT ATRES	895,650	70.47	0.2646	-
Total	1,271,000	100	0.45	180

Source: Stratas Advisors, 2015-2016.

B.5.5 Case 5: Maximum amount of compliant marine fuels

Table 107 and Table 128 show refinery H_2 consumption and sulphur production, respectively, in the sensitivity case that produces the maximum amount of compliant marine fuels.

Table 127 H_2 consumption Asia & Middle East (2020) Maximum amount of compliant fuels - MMSCFD

Regional H_2 consumption (2020)		
Region/Year	H_2 consumption (MMSCFD) (1)	H_2 production capacity (2)
	2020	2020
Asia	8,238 (7,759)	3,663
Middle East	2,890 (2,827)	1,478

Source: Stratas Advisors, 2015-2016.

(1) Consumption numbers in bracket () are 2020 base case - Case 1 numbers.

(2) H_2 production capacity based on Oil and Gas Journal data.

Table 128 Sulphur production & capacity in Asia & Middle East (2020) maximum amount of compliant fuels - tonnes per day

Regional sulphur production and capacity		
	Sulphur production (Metric tonne) - Model (1)	Sulphur production capacity OGJ (2)
Region/Year	2020 (Case 1)	2020
Asia	24,851 (24,680)	22,590
Middle East	11,969 (11,592)	5,147

Source: Stratas Advisors, 2015-2016.

(1) Production numbers in bracket () are 2020 base case - case 1 numbers.

(2) Sulphur plant capacity based on Oil and Gas Journal data.

Refinery desulphurization capacity utilization and conversion in Asia and the Middle East in the maximum production case is shown in Table 129.

Table 129 % Capacity utilization Asia & Middle East - Maximum case, Case 5 (2020)

PROCESS	Asia (Maximum-Marine Case 5)	Asia (Base Case 1)	Middle East (Maximum-Marine Case 5)	Middle East (Base Case 1)
CDU	70%	68%	83%	74%
HYDROCRACKER	83%	76%	83%	83%
GOHDS TOTAL	83%	83%	83%	83%
ATRES HDT	83%	83%	83%	46%
H-OIL	83%	83%	83%	83%
GASOIL HDS	31%	51%	0%	0%
AGO HDS	30%	30%	72%	73%
LCO HDS	1%	22%	0%	2%
DELAYED COKER	52%	48%	83%	83%

Source: Stratas Advisors, 2015-2016.

The composition of HFO with a sulphur content of 0.50% m/m or less in the maximum amount of compliant marine fuels is presented in Table 130 and Table 131 for Asia and the Middle East, respectively.

Table 130 Asia HFO (<0.50% m/m S) blending - Maximum case (2020)

Asia HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
ATRES	203,627	8.22	2.088	-
SR AGO	63,281	2.55	1.037	-
TR LT DIST	725,685	29.3	0.011	-
H-OIL BTMS	241,080	9.73	1.000	-
TRT ATRES	1,243,328	50.19	0.261	-
Total	2,477,000	100	0.45	41

Source: Stratas Advisors, 2015-2016.

Table 131 Middle East HFO (<0.5 % m/m S) (2020) - Maximum marine case (Case 5) (2020)

Middle East HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
HC UCO	31,615	4.12	0.003	-
KEROSENE	161,863	21.08	0.371	-
TRT AGO TO HO	130,076	16.94	0.249	-
H-OIL HY DIST	89,943	11.71	0.197	-
H-OIL BTMS	123,399	16.07	1.000	-
TRT ATRES	231,104	30.09	0.430	-
Total	768,000	100.00	0.450	39

Source: Stratas Advisors, 2015-2016.

B.5.6 Case 6: The impact of high sulphur crude

If the Middle East would use a crude slate with a higher average sulphur content, the refinery H_2 consumption and sulphur production are projected to be higher than in the base case, as indicated in Table 132 and Table 133.

Table 132 H_2 consumption Asia & Middle East (2020) high sulphur case, Case 6 - MMSCFD

Regional H_2 consumption (2020)		
Region/Year	H_2 consumption (MMSCFD) (1)	H_2 production capacity (2)
	2020	2020
Middle East	2,824 (2,827)	1,478

Source: Stratas Advisors, 2015-2016.

(1) Consumption numbers in bracket () are 2020 base case - Case 1 numbers.

(2) H_2 plant capacity only (Naphtha reformer capacity not included).

Table 133 Sulphur production & capacity Asia & Middle East (2020) high-sulphur crude case - tonnes per day

Regional sulphur production and capacity		
Region/Year	Sulphur production (metric tonne) - Model(1)	Sulphur production capacity (2)
	2020 (Case 1)	2020
Middle East	11,860 (11,592)	5,147

Source: Stratas Advisors, 2015-2016.

(1) Production numbers in bracket () are 2020 base case - Case 1 numbers.

(2) Sulphur plant capacity based on Oil and Gas Journal data.

The refinery desulphurization capacity utilization and conversion will be higher when the average sulphur content of the crude slate is higher, as shown in Table 134.

Table 134 % Capacity utilization Middle East - High-sulphur case (2020)

PROCESS 2020 capacity utilization - High S case (Case 6)	Middle East High S Case (Case 6)	Middle East Base Case (Case 1)
CDU	82%	74%
HYDROCRACKER	83%	83%
GOHDS TOTAL	83%	83%
ATRES HDT	46%	46%
H-OIL	83%	83%
GASOIL HDS	0%	0%
AGO HDS	48%	73%
LCO HDS	0%	2%
DELAYED COKER	83%	83%

Source: Stratas Advisors, 2015-2016.

Table 135 shows how HFO with a sulphur content of 0.50% m/m or less is projected to be blended in case the average sulphur content of the crude slate in the Middle East is higher than in the base case.

Table 135 HFO (<0.50% m/m S) blending Middle East - High-sulphur case, Case 6, (2020)

Middle East HFO blending (2020), Case 6				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
HC UCO	31,132	9.73	0.003	-
KEROSENE	7,573	2.37	0.404	-
TRT KERO	61,118	19.10	0.013	-
TRT AGO TO HO	13,355	4.17	0.259	-
H-OIL HY DIST	89,943	28.11	0.197	-
H-OIL BTMS	99,194	31.00	1.000	-
TRT ATRES	17,685	5.53	0.468	-
Total	320,000	100.00	0.450	180

Source: Stratas Advisors, 2015-2016.

B.5.7 Case 7: Increasing low viscosity blend stock in HFO

Table 136 through Table 142 show the blending components of HFO with a fuel content of 0.50% m/m or less for every region in case low viscosity blending stocks (kerosene, light gas oil) are used to a maximum extent.

Table 136 Africa HFO blending (2020), Case 7, barrels/day

Africa HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
CUTTER STOCK	58,108	36.32	0.127	-
ATRES	8,194	5.12	1.405	-
TR LT DIST	47,423	29.64	0.0002	-
H-OIL BTMS	46,274	28.92	1.000	-
Total	160,000	100	0.450	10

Source: Stratas Advisors, 2015-2016.

Table 137 Asia HFO blending (2020), Case 7, barrels/day

Asia HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
ATRES	114,489	6.06	2.103	-
TR LT DIST	291,104	15.4	0.030	-
H-OIL BTMS	241,080	12.76	1.000	-
TRT ATRES	1,243,327	65.78	0.263	-
Total	1,890,000	100	0.450	111

Source: Stratas Advisors, 2015-2016.

Table 138 North America HFO blending (2020), Case 7, barrels/day

North America HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
VISBR TAR	9,071	2.88	3.494	-
TRT LCO	112,060	35.63	0.107	-
LCO	11,703	3.72	0.714	-
SLURRY	45,320	14.41	0.939	-
H-OIL BTMS	40,112	12.75	1.000	-
TRT LT DIST -MED HDS	76,694	24.39	0.019	-
TR LT DIST	18,770	5.97	0.000	-
TRT KERO	649	0.21	0.065	-
TRT KERO (DSL TR)	111	0.04	0.326	-
Total	314,490	100	0.444	10

Source: Stratas Advisors, 2015-2016.

Table 139 Latin America HFO blending (2020), Case 7, barrels/day

Latin America HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
ATRES	92,803	21.19	0.591	-
SLURRY	47,674	10.88	0.595	-
COKER/VBR HY DIST	29,559	6.75	0.591	-
IMP CUTTER	10,000	2.28	0.250	-
TRT LT DIST -MED HDS	27,943	6.38	0.012	-
TR LT DIST	214,974	49.08	0.000	-
VCRES	15,047	3.44	4.934	-
Total	438,000	100	0.450	37

Source: Stratas Advisors, 2015-2016.

Table 140 Middle East HFO blending (2020), Case 7, barrels/day

Middle East HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
HC UCO	34,033	10.64	0.003	-
CUTTER STOCK	5,161	1.61	1.908	-
KEROSENE	3,915	1.22	0.386	-
SR AGO	3,102	0.97	1.684	-
TRT LCO TO HO	8,569	2.68	0.382	-
H-OIL HY DIST	89,943	28.11	0.197	-
H-OIL BTMS	46,998	14.69	1.000	-
TRT ATRES	128,277	40.09	0.433	-
Total	320,000	100.00	0.450	180

Source: Stratas Advisors, 2015-2016.

Table 141 - Europe HFO blending (2020), Case 7, barrels/day

Europe HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
SR DIESEL	224,083	23.05	0.552	-
FCC LCO	113,224	11.65	0.587	-
TR LT DIST	27,316	2.81	0.044	-
TRT AGO 85%	351,048	36.12	0.148	-
TRT PURCH GASOIL	5,404	0.56	0.015	-
H-OIL BTMS	152,943	15.73	1.000	-
TRT ATRES	97,981	10.08	0.250	-
Total	972,000	100.00	0.450	17

Source: Stratas Advisors, 2015-2016.

Table 142 - Russia & CIS HFO blending (2020), Case 7, barrels/day

Russia & CIS HFO Blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
TR LT DIST	79,286	61.94	0.037	-
H-OIL BTMS	48,714	38.06	1.000	-
Total	128,000	100	0.450	66

Source: Stratas Advisors, 2015-2016.

B.5.8 Case 8: Maximum refinery utilization

In case refineries aim to maximize distillate and gasoline production by utilization of hydrocracker, coker, VGO hydrotreater, residual desulphurization, visbreaker, oligomerization, Hydrocracker utilization rate in North America will increase from 69% to 82%. Atmospheric residue hydro treating (ATRES HDT) utilization rate in North America will also increase from 10% to 51%. In Asia, gasoil hydrodesulfurization utilization rate will increase from 51% to 83%.Most of the other processes have the same or very similar utilization rates as in the base case, as shown in
Table 143.

Table 143 % Utilization 2020 Case 8 and (2020 Case 1)

Regional Process Unit Utilization Percentage (2020 Case 8, (2020 Case 1))							
PROCESS	Africa	Asia	Europe	North America	Latin America	Middle East	Russia & CIS
CDU	57% (57%)	68% (68%)	60% (60%)	65% (64%)	55% (55%)	82% (74%)	60% (60%)
HYDROCRACKER	83% (83%)	76% (76%)	83% (83%)	82% (69%)	83% (83%)	83% (83%)	56% (56%)
GOHDS TOTAL	0% (0%)	83% (83%)	83% (83%)	81% (81%)	71% (65%)	83% (83%)	75% (75%)
ATRES HDT	0% (0%)	83% (83%)	83% (83%)	51% (10%)	0% (0%)	46% (46%)	0% (0%)
H-OIL	83% (83%)	83% (83%)	83% (83%)	79% (76%)	0% (0%)	83% (83%)	36% (36%)
GASOIL HDS	81% (81%)	83% (51%)	83% (83%)	6% (13%)	83% (83%)	0% (0%)	0% (0%)
AGO HDS	81% (81%)	46% (30%)	83% (83%)	5% (2%)	83% (83%)	48% (72%)	0% (0%)
LCO HDS	0% (0%)	36% (22%)	0% (0%)	2% (11%)	0% (0%)	0% (2%)	0% (0%)
DELAYED COKER	83% (83%)	51% (48%)	46% (46%)	70% (70%)	55% (55%)	83% (83%)	38% (38%)

Source: Stratas Advisors 2015-2016.

Note: The numbers in brackets are from Case 1, 2020.

Table 144 through Table 150 show the blending components of HFO with a fuel content of 0.50% m/m or less for every region in this case.

Table 144 Africa HFO blending (2020), Case 8, barrels/day

Africa HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
CUTTER STOCK	58,108	36.32	0.127	-
ATRES	8,194	5.12	1.405	-
TR LT DIST	47,423	29.64	0.0002	-
H-OIL BTMS	46,274	28.92	1.000	-
Total	160,000	100	0.450	10

Source: Stratas Advisors 2015-2016.

Table 145 Asia HFO blending (2020), Case 8, barrels/day

Asia HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
SLURRY	57,339	3.03	2.470	-
ATRES	36,375	1.92	2.213	-
TRT KERO	2,389	0.13	0.013	-
TR LT DIST	309,494	16.38	0.000	-
H-OIL BTMS	241,080	12.76	1.000	-
TRT ATRES	1,243,324	65.78	0.277	-
Total	1,890,000	100	0.450	111

Source: Stratas Advisors 2015-2016.

Table 146 North America HFO blending (2020), Case 8, barrels/day

North America HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
VISBR TAR	9,071	2.88	3.494	-
LCO	102,812	32.69	0.512	-
SLURRY	40,504	12.88	0.816	-
TRT ATRES	65,879	20.95	0.360	-
TRT LT DIST -MED HDS	76,694	24.39	0.019	-
TR LT DIST	18,770	5.97	0.904	-
TRT KERO	649	0.21	0.065	-
TRT KERO (DSL TR)	111	0.04	0.326	-
Total	314,490	100	0.444	10

Source: Stratas Advisors 2015-2016.

Table 147 Latin America HFO blending (2020), Case 8, barrels/day

Latin America HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
ATRES	128,133	29.25	0.591	-
SLURRY	48,619	11.10	0.605	-
IMP CUTTER	5,000	1.14	0.250	-
TR LT DIST	241,702	55.18	0.000	-
VCRES	14,546	3.32	4.921	-
Total	438,000	100	0.450	37

Source: Stratas Advisors 2015-2016.

Table 148 Middle East HFO blending (2020), Case 8, barrels/day

Middle East HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
HC UCO	31,132	9.73	0.003	-
KEROSENE	7,573	2.37	0.404	-
TRT KERO	61,118	19.10	0.013	-
TRT AGO TO HO	13,355	4.17	0.259	-
H-OIL HY DIST	89,943	28.11	0.197	-
H-OIL BTMS	99,194	31.00	1.000	-
TRT ATRES	17,685	5.53	0.468	-
Total	320,000	100.00	0.450	180

Source: Stratas Advisors 2015-2016.

Table 149 Europe HFO blending (2020), Case 8, barrels/day

Europe HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
SR DIESEL	224,083	23.05	0.552	-
FCC LCO	113,224	11.65	0.587	-
TR LT DIST	27,316	2.81	0.044	-
TRT AGO 85%	351,048	36.12	0.148	-
TRT PURCH GASOIL	5,404	0.56	0.015	-
H-OIL BTMS	152,943	15.73	1.000	-
TRT ATRES	97,981	10.08	0.250	-
Total	972,000	100.00	0.450	17

Source: Stratas Advisors 2015-2016.

Table 150 - Russia & CIS HFO blending (2020), Case 8, barrels/day

Russia & CIS HFO blending (2020)				
Component to Blend	Volume (barrels/day)	Vol%	SUL % (m/m)	Viscosity (cSt at 50°C)
TR LT DIST	79,286	61.94	0.037	-
H-OIL BTMS	48,714	38.06	1.000	-
Total	128,000	100	0.450	66

Source: Stratas Advisors 2015-2016.

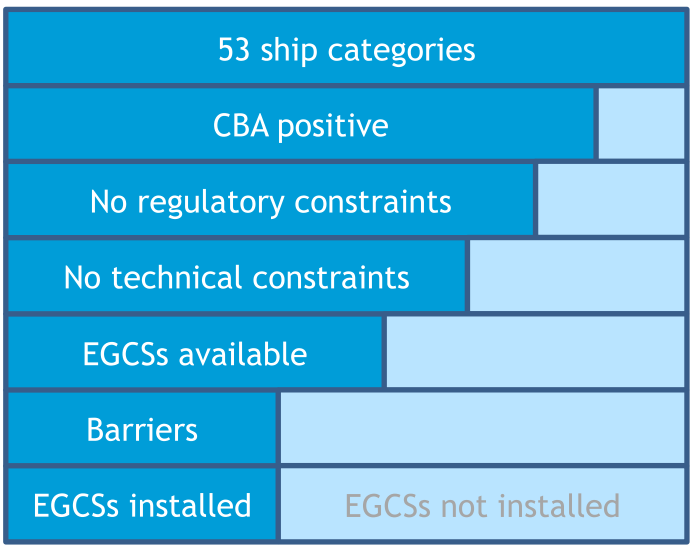
Annex C EGCS uptake projections

C.1 Introduction

The projection of the uptake of EGCSs and their use in 2020 is based on economic considerations, technical and operational constraints, availability of EGCSs and installation capacity, and regulatory uncertainty. We apply a five-stage filter model to each of the 53 generic ship type and size categories defined in the Third IMO GHG Study 2014:
1. Economic analysis. For each generic ship category, the costs and benefits of an EGCS are estimated. The costs are the sum of the annualised capital expenditures and the operational expenditures. The benefits are the savings of fuel expenditures, which depend on the price difference of low-sulphur and conventional fuels. This is discussed in more detail in Section C.2.
2. Regulatory constraints to operating EGCSs. While the use of EGCSs is allowed under Marpol Annex VI (Regulation 4) and under the national and regional ECA regulations, the discharge of washwater is sometimes constrained or prohibited because of water quality considerations. The impact of these regulations on the business case and investments are discussed in Section C.3.
3. Technical and operational feasibility. Even if the cost-benefit analysis is positive, there may be reasons why EGCSs cannot be installed on ships, e.g. because of space limitations, impacts on stability or compatibility with Tier III NO_x regulations. The impact of the technical and operational feasibility is analysed in Section C.4.
4. Availability of EGCSs. Even if the cost-benefit analysis is positive and installing EGCSs is technically and operationally feasible, their availability may be limited due to the production capacity of EGCSs or the installation capacity. These are analysed in Section C.5.
5. Other barriers which often relate to the institutional arrangements in the shipping sector. These are analysed in Section C.6.

Figure 14 shows a graphical representation of the EGCS uptake model.

Figure 14 Graphical representation of EGCS uptake model



C.2 Economics of EGCS use

The installation of an EGCS is considered to be economical when the benefits exceed the costs. The costs are the sum of the annualised capital expenditures and the operational expenditures. The benefits are the savings of fuel expenditures, which depend on the price difference of low-sulphur and conventional fuels.

C.2.1 Capital expenditures of EGCSs

EGCS investments

The investments in EGCSs comprise the cost of the EGCS and the installation, design and engineering. As a rule of thumb, the total investments are twice the cost of the EGCS. We do not take foregone revenues into account because we assume that most ships will install EGCSs during regular maintenance, dry dockings or possibly while installing ballast water management systems (see also Section C.5.2).

Different types of EGCSs require different levels investments. Open loop EGCSs are, on average, cheaper than closed loop EGCSs, which require additional pumps, cooling units for washwater, tanks for sludge, et cetera. Hybrid EGCSs, which can operate both in open and closed loop mode so need two sets of pumps and piping, are the most expensive.

There are economies of scale in the building and installation costs of EGCSs. Some elements of an EGCS are required, regardless of the size of the system, such as monitoring modules and control systems. The capacity of the EGCS itself depends on its cross-section, whereas the amount of steel required is roughly proportional to the circumference. As a result, large EGCSs require a lower investment per unit of engine power than small EGCSs.

There is a wide variety of estimates of the cost of EGCSs in the literature (see Table 151). Some of the literature values are quite old, and few capture the economies of scale.

Table 151 Overview investment costs EGCS in the literature

Study	EGCS type	Newbuild Capex ($/kW)	Retrofit Capex ($/kW)	Installation costs ($/kW)	Basis for cost estimate
Entec (2010)	Open loop	134	171	Included in the Capex	Unknown
AEA (2009)	Open loop - closed loop	110-220	220-440	Included in the Capex	Manufacturer estimates (Wärtsilä, 2009; Marine and Energy Consulting, 2009)
SKEMA (2010)	Open loop	130	185	Included in the Capex	Based on estimates in (Entec UK, 2005)
DMA (2012)	Unknown	165	165	198-247*	Data provided by MAN Diesel & Turbo and Wärtsilä

Study	EGCS type	Newbuild Capex ($/kW)	Retrofit Capex ($/kW)	Installation costs ($/kW)	Basis for cost estimate
Greenship (2012)	Closed loop		399		CAPEX is based on quotes from 3 shipyards
DFDS	Hybrid		~275		DFDS
(IMO, 2015)	Unknown	330	368	Including off-hire and dry docking	Based on data of a DFDS-vessel from Alfa Laval/Aalborg
Wärtsilä (2014)	Open loop: Hybrid:		206 248	240 303	Wärtsilä
DeltaLangh (2015)	Hybrid	126			DeltaLangh
(DfT, 2014) (AMEC, 2014)		190-308	229-314	Included in Capex	(Entec, 2010), unit costs inflated to 2014 price level

*The lower margin refers to new build costs, the upper margin to retrofit costs.

In addition, the recent UK impact assessment of the implementation of Directive 2012/33/EU (EC, 2012) on the prevention of air pollution from shipping (MCA, 2014), assumes EGCS costs as presented in Table 152.

Table 152 EGCS unit costs in $/kW (price level 2013)

Engine	New	Retrofit
Main engine	$ 190	$ 229
Main and auxiliary engine	$ 308	$ 314

Source: (MCA, 2014).

These values are assumed to be constant over time and have been adjusted to the price level in 2013. The EGCS costs differ among types of ships, as it is assumed that auxiliary engines from bulk carriers, general cargo and tankers run on MGO and thus EGCSs costs are only based on the main engine. For all other types of vessels, the cost of EGCSs includes both the main and auxiliary engines.

Many reports on EGCS costs refer back to studies performed around 2009 and 2010 and some of these studies are based on data from older studies. Most of the above listed EGCS costs are therefore quite outdated and current EGCS cost might be lower due to commercialization. In order to get a more recent estimate of EGCS costs, we have liaised with EGCS manufacturers and with shipping companies that have recently invested in EGCSs or studied the costs and benefits of doing so. An estimate based on their inputs has been presented to an internet survey, which yielded some new inputs and a revised estimate of investment costs, presented in Table 153. Although we expect that the costs of EGCSs will come down when demand increases and designs are standardised, we have not taken the impact of innovation on costs into account in our cost estimates.

Table 153 EGCS investment costs used in this study

EGCS type	Fixed investment costs (million USD)	Variable investment costs (USD per kW of installed engine power)
Open loop, retrofit	2.3	55
Open loop, newbuild	1.9	38
Hybrid, retrofit	2.8	58
Hybrid, newbuild	2.4	44

Source: CE Delft.

Financial parameters

EGCSs have a lifetime of up to several decades. Therefore, the capital investments need to be translated into annual costs in order to assess the costs and benefits. Shipping companies have two different ways to do this. The first, which is most common in retrofit projects, is to assess the payback time. The investment is divided by the annual sum of the operational expenditures and fuel expenditure savings.

We have liaised with shipping companies on acceptable payback times. Different companies have different thresholds for acceptability, but it appears that payback times up to 3-5 years are required for investments in retrofits by most shipping companies.

The second way to assess the value of an investment is to calculate the annuity of the investment, i.e. the amount that would need to be paid if a load was taken out to finance the investment. This is a method typically applied to EGCS installations on new ships. The annuity can be calculated from the investment, the weighted average cost of capital and the economic life of the EGCS.

The weighted average cost of capital depends to a large extent on the financial health of the shipping company. From the interviews with stakeholders it appears that EGCSs can be fully financed externally. In the current market, companies are often able to get loans for an interest rate of 2-3%. The economic life of an EGCS is usually similar to the economic life of a ship. We have taken a conservative approach and assumed it to be ten years.

Table 154 summarises the financial parameters used in this study.

Table 154 Financial parameters used in this study

Newbuilds: discount rate	3%
Newbuilds: economic life	10 years
Retrofits: payback period	3 years

Source: CE Delft.

The financial parameters have been presented to stakeholders in an internet survey. Most of the respondents that answered the question agreed with these assumptions. Of the respondents that did not agree, most stated that a payback period of four years is too high and a discount rate of 3% is too low. However, no information sources have been provided to provide arguments for these statements, nor have respondents suggested alternative values.

We have carried out a sensitivity analysis that shows that an increase in the discount rate from 3 to 6% only has a minor impact on the share of newbuilds for which EGCSs are a cost-effective option. A reduction of the required payback period for retrofits from 4 to 3 years reduces the share of fuel used by ships for which an EGCS is a cost-effective solution by 25% (from 40% of the fuel down to 30%). An even more stringent requirement of a 2 year payback time reduces the share of fuel by 60% (from 40 to 15%). The largest reduction was for ships with relatively small engines. On the basis of this information, we have adjusted the payback period to 3 years and will undertake a sensitivity analysis of 2 and 4 years.

C.2.2 Operational expenditures of EGCSs

- the operational expenditures of EGCSs comprise:
- the additional energy required for the pumps, heat exchangers, hydrocyclones, and other equipment;
- disposal of sludge;
- maintenance;
- in the case of closed loop EGCSs, or hybrid EGCSs operating in closed loop mode, consumption of caustic soda.

According to CE Delft (CE Delft, 2015a) the operational costs of EGCSs are typically a few percent of the annual capital expenditures. We have liaised with EGCS manufacturers and with shipping companies that are operating EGCSs. This has resulted in a new estimate of operational costs, presented in Table 155.

Table 155 EGCS operational costs used in this study

EGCS type	Operational costs
Open loop	1% additional fuel + USD 13,000 + 0.4 * $P_{M.E.}$ (kW)

Source: CE Delft.

Note: $P_{M.E.}$(kW) is the power of the main engine in kilowatt.

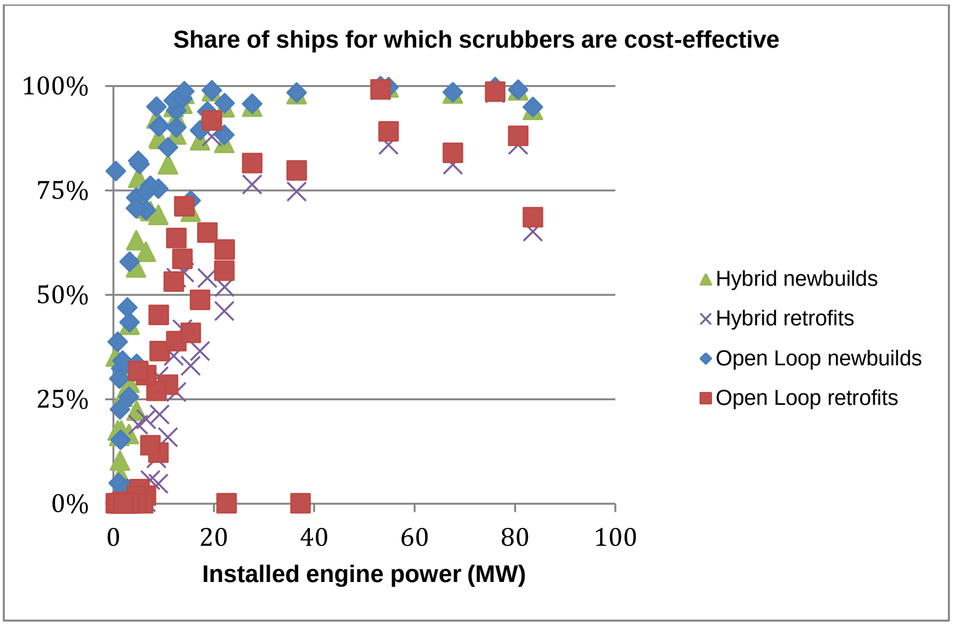
C.2.3 Cost-effectiveness of EGCSs

This section presents the results of the cost-effectiveness modelling of EGCSs for retrofits and newbuilds.

For all ship type and size categories defined in the Third IMO GHG Study 2014, data from that study on installed engine power, fuel consumption, etc. were compiled. In order to take into account the variance between ships, both the average fuel consumption and the standard deviation were calculated for each ship type. Using these data and the input data presented in Sections C.2.1 and C.2.2, the share of ships within each category was calculated for which an investment in an EGCS would be cos- effective. The fuel prices used are presented in Table 32.

Figure 15 shows the share of ships within each ship type for which EGCSs are cost-effective as a function of the total installed engine power. For ships with engines below 5 MW, EGCSs are hardly ever cost-effective as retrofits at the assumed fuel prices. For new builds, the CBA is more often positive. The share of ships for which EGCSs are cost-effective increases for ship types with an average installed power between 5 and 20 MW. Above 20 MW, EGCSs are cost-effective for a large share of ships.

Figure 15 **EGCSs are more cost-effective for ships with larger engines**



Source: CE Delft.

By way of an example, Table 156 shows the cost-effectiveness of EGCSs for 100,000- 199,999 dwt bulk carriers. These ships have an average engine power of 17 MW. We estimate that, with a fuel price difference of 129 USD, an investment in an open loop EGCS for new ships would be cost-effective for 89% of the ships, while a hybrid EGCS would be cost-effective for 87% of newbuildings. Retrofits are significantly less often cost-effective for retrofits: for 66% of the ships for open loop EGCSs and 57% for hybrid EGCSs.

Table 156 **Example of cost-effectiveness of EGCSs: a 100,000-199,999 dwt bulker**

Type of EGCS	Capex (mln USD)	Opex (1,000 USD per annum)	Share of ships for which an EGCS is cost-effective
Open loop newbuildings	2.5	20	89%
Open loop retrofit	3.2	20	66%
Hybrid newbuildings	3.1	20	87%
Hybrid retrofit	3.8	20	57%

Source: This report.

C.3 Regulatory constraints to using EGCSs

Regulations constrain the discharge of washwater of EGCSs. There are two types of regulations:
- washwater criteria, setting standards that washwater needs to meet to be discharged;
- prohibitions to discharge washwater.

The IMO has developed washwater criteria setting limits for the acidity, the concentration of polyaromatic hydrocarbons (PAHs), turbidity and nitrate (MEPC, 2015). The EU legislation has transposed these criteria in the 2012 amendment of the Council Directive relating to a reduction in the sulphur content of certain liquid fuels (EC, 1999). The US Environmental Protection Agency (EPA) has issued criteria which have different pH limits and different measurements of pH (EPA; NPDES, 2009). However, although the criteria are different, all EGCSs that are currently on the market can meet both sets of criteria, either continuously or by changing their operations (e.g. diluting the washwater to a greater extent).

Discharge of washwater is restricted or prohibited in several ports (e.g. Antwerp, Hamburg), estuaries (e.g. the Wese) and in coastal waters (e.g. Alaska, Belgium). Most EGCSs have the possibility to operate in a zero-discharge mode for some time. Open loop EGCSs often have the possibility to store washwater for a limited amount of time, or can be fitted with water holding tanks. Hybrid EGCSs, when operating in closed loop mode, do not discharge washwater.

There is an ongoing debate in several European countries about whether washwater discharges are compatible with the Water Framework Directive 2000/60/EC (EC, 2000) and the Marine Strategy Framework Directive 2008/56/EC (EC, 2008), even when they meet the IMO washwater criteria. These directives require EU Member States to develop strategies to achieve a good environmental status by 2020. Many coastal waters currently do not meet this standard. Both directives refer to the precautionary principle in their preambles, illustrating the importance of environmental protection through preventative decision-taking in the case of risk.

Even though the areas where washwater discharges are restricted are relatively small, they have an impact on the investment level in two ways. First, because investments in EGCSs are currently only attractive for ships that consume a large share of their fuel in ECAs, even relatively small areas may have a large impact. Second, the uncertainty about future regulations is making the business case uncertain. If the discharge of washwater was to be restricted in more areas, the cost-benefit analysis of installing EGCSs would deteriorate because either hybrid or closed loop EGCSs would be needed, or larger storage tanks would be needed or ships would need to use distillate fuels when operating in no-discharge areas.

Most respondents to the internet survey were of the opinion that discharge prohibitions will spread across the globe and will result in shipping companies opting for hybrid EGCSs,
if any.

For the future projections of EGCS uptake, two developments are important:
1. A global requirement to use low-sulphur fuels will reduce the share of fuel consumed in areas where discharges are restricted, because the total amount of fuel under the tighter limit will increase. This improves the business case for using low-sulphur fuels. This has already been taken into account in the cost-effectiveness analysis presented in Section C.2.
2. Regulations may or may not become more settled in the coming period. The most optimistic scenario will result in a negligible impact of the regulatory uncertainty, a more pessimistic scenario may be that the uncertainty prevails until 2020. That would imply that ships will only consider installing hybrid EGCSs because they can be operated in a zero discharge mode for extended periods of time.

C.4 Technical and operational constraints to installing EGCSs

Technical and operational constraints to installing EGCSs may comprise:
1. The space required for EGCSs and the impact on cargo space.
2. The impact on the stability of ships.
3. The impacts on required power.
4. The compatibility of EGCSs with NO_x Tier III requirements.

Each of these potential constraints is discussed on more detail below.

Space required for EGCSs
The space required for EGCS comprises the space for the EGCS itself, water and effluent treatment systems, pumps, pipings, sludge and water tanks, et cetera. Existing ships have not been designed for EGCSs. Still, in many cases, there is sufficient space in or above the engine room to place the EGCS. EGCSs can be designed in many ways and much of the innovation in EGCS technology has been aimed at reducing the space requirements for EGCSs. EGC suppliers have for example developed so-called Inline EGCSs, offering very compact configurations, with smaller space requirements than traditional EGCSs. Water treatment systems have been developed that are significantly more compact than designs of five years ago.

The evidence presented to us suggests that in many cases, EGCSs can be designed to fit the available space. For ships that have free deck space available or large engine rooms, fitting EGCSs is almost never a problem. In some cases, however, cargo space may need to be sacrificed. This appears to be especially the case for container ships. For large container ships with equally large EGCSs, examples are available of EGCSs that would take up the space of a few forty-foot containers. Whether this is acceptable, depends on the company. In the internet survey, RoPax vessels were mentioned as a vessel type for which space limitations may prevent the installation of EGCSs. There are, however, several examples of RoPax vessels on which EGCSs have been installed.

In new ships, EGCSs can be incorporated in the design of the ship, thus eliminating the lack of space.

Impacts on the stability of the ship
EGCSs may weigh several tonnes and often a large share of this weight has to be high up in the stack. This may affect the stability of the ship. The impact on stability may be larger for smaller ships and for ships that have a smaller stability margin.

The interviews and the internet survey suggest that, except for some very special ship designs, stability issues have not been a constraint on installing EGCSs. The possible exceptions that have been mentioned in the internet survey are small RoRo and RoPax vessels and Panamax container ships. If the impact is significant, it can often be remedied by increasing the ballast of a ship.

Impacts on required power
EGCSs require electrical power to operate pumps and other equipment. For new ships, the power requirements can be taken into account in the design phase. For existing ships, additional generator capacity may be required.

The information presented to us indicates that most existing ships, especially large ones, have sufficient generator capacity to power the EGCS in addition to the existing equipment. However, container feeders and RoRo ships with 4-stroke engines may not have enough surplus generating capacity. In those cases, additional generators need to be installed which increase the costs of the EGCS. In our model, we have assumed that container ships with a capacity smaller than 1000 TEU and RoRo ships with a deadweight of less than 5000 tonnes will not install EGCSs because of the power requirements.

Compatibility of EGCSs with NO_x Tier III requirements

Ships that operate in the North American and the United States Caribbean Sea ECAs and are built in or after 2016 need to comply with Tier III NO_x requirements. When not using LNG, their engines will most probably need to be fitted with either an Exhaust Gas recirculation (EGR) system or with Selective Catalytic Reduction (SCR). In both cases, questions have been raised about the compatibility of these NO_x emission reduction technologies with EGCSs (see e.g. (DNV, 2012)).

The problem of combining an SCR with an EGCS is that an SCR may be less efficient when there is a high concentration of sulphur oxides in the exhaust, while they also require a high temperature so cannot be placed after the EGCS, which cools the exhaust considerably.

A closer examination of the problem reveals that sulphur oxides only present a challenge to the SCR when the temperature is too low. In that case, ammonia and sulphuric acid may condense as ammonium bisulphate which may block the catalyst (IACCSEA, 2013). In preparation of the NO_x Tier III requirements, engine manufacturers have developed engines that have been optimised for operation in combination with an SCR. These engines often have active temperature control of the exhaust. SCRs have been optimized for high-sulphur HFO operation by selecting suitable catalyser element geometry, and by efficient soot-blowing to avoid deposits.

Hence, the risk of catalyst blocking has been minimised and SCRs can be used in combination with high-sulphur fuels. This also means that an EGCS can be installed after the SCR in a combination that reduces both the NO_x and the SO_x concentrations in the exhaust.

The interaction between an engine with an EGR and an EGCS is even less problematic. An EGR system has an EGCS to sulphur and PM from the engine exhaust gas so this gas can be re-introduced to the engine without damaging it. Therefore, the exhaust gas that is not recirculated has a lower sulphur content and the exhaust gas EGCS can be smaller in size (Alfa Laval Aalborg ; Man Diesel & Turbo, 2014).

Apart from test stands at EGCS manufacturers where different systems are combined, there are several ships on which the systems have been used in combination for an extensive period.

C.5 EGCS availability

C.5.1 EGCS manufacturing capacity

The availability of EGCSs is determined by the manufacture of components, logistics of bringing them together and pre-assembling parts of the system prior to installation. We have no indications that any of these steps will present a bottleneck in EGCS installations.

All the components of EGCSs - the EGCS unit, water treatment systems, monitoring equipment, et cetera, are mass produced for land-based installations. Hence, the production of the components should not constitute a limitation on the availability of EGCSs. Neither should logistics.

Pre-assembling parts of systems may benefit from suppliers setting up shop at or near a yard where many EGCSs are installed. However, even without a local workshop it would be possible to install EGCSs. Hence, we do not consider this to impose a constraint on the availability.

C.5.2 Scrubber installation capacity

We distinguish between the capacity of yards to install EGCSs on new ships and on existing ships.

For new ships, the capacity is limited by the capacity to build new ships. The deliveries of new ships are projected to amount to 70,000 million GT in 2015 and 2016 (Shipbuilders association of Japan, 2015). This is approximately 30% below the average capacity between 2010 and 2012, which was 98,000 million GT. Expressed in dwt, the peak seems to be even higher. Clarksons estimates the deliveries in 2012 at 133,000 million dwt in 2012 and projects 65,000 million dwt in 2015 and 85,000 in 2016. Hence, it appears that there is ample capacity to install EGCSs on new ships.

For retrofits, the time required to install an EGCS on an existing ship is estimated to range from two to four weeks, depending on the design of the ship. There is anecdotal evidence of installations that have taken more time, sometimes considerably more, but these were typically installations at yards that did not have an extended experience with installing EGCSs. As yards develop know-how, and when EGCSs are installed on similar ships or sister ships, they are able to shorten the time in dock. EGCS manufacturers are also innovating to reduce the time required in dock. On some ship types, such as RoPax and cruise ships, EGCSs have been installed while the ships were sailing. This may not be possible for ships with limited accommodation or with single large main engines.

The time in dock is only a part of the total time it takes to install an EGCS. The entire process from the investment decision to approval of the system by the flag state may take up to ten months.

The installation capacity depends on the availability of dry dock and its manpower, which is usually used for the Renewal Survey by the Flag States (actually the Special Survey by Class Society) and the intermediate survey. In order to avoid off-time, it is likely that ships try to retrofit an EGCS during a regular dry docking.

When considering the dry dock capacity towards 2020, it should be noted that all existing ships, which have not yet installed Ballast Water Management Systems (hereafter BWMS), are required to install BWMSs in this period.

The Ballast Water Management Convention (hereafter BWMC), together with the agreement by the Assembly Resolution A.1088(28) (IMO Assembly, 2014) required that existing ships, constructed before the date of entry into force of the BWMC, should install BWMS by the date of the first renewal survey of the IOPP Certificate following the date of entry into force of the BWMC. It is likely that the BWMC will enter into force in 2017. As the renewal interval of the IOPP Certificate is usually five years, all the existing ships should install BWMS between 2017 and 2021.

According to the document submitted by Liberia (MEPC 69/INF.22), the total annual dry dock capacity is approximately 12,500 ships. However, after accounting for the required capacity to do repairs, intermediate surveys, and taking into consideration that the installation of a BWMS will increase the amount of time in dry dock, the submission estimates that only 4,800 ships can be retrofitted annually with BWMSs in the dry dock. Because the IOPP Certificate will be issued when the ship is in dry dock, and the BWMS installation needs to be completed before the IOPP renewal, the priority during the regular survey will be to install a BWMSs rather than EGCSs.

This leaves the question whether during the same dry dock it will be possible to install an EGCS. Manufacturers that have experience with installing BWMSs and EGCSs have informed us that simultaneous work on two different systems should not be a problem, because the components of these systems are not adjacent. Thus several teams can work simultaneously. However, because of the priority is given to the BWMS, it may be required to prepare for or finalise the installation of the EGCS while the ship is in operation, and use the time in dry dock to install the large components of the system. Moreover, shipowners may not want to carry out two large projects simultaneously in order to minimise the risk of time overruns.

Based on these considerations, we estimate that about 50% of the ships can install both systems simultaneously, so there is an annual capacity of about 2,500 ships for the retrofitting of EGCSs at repair yards. In addition, some ships can install EGCSs while in operation, but because of constraints we estimate this number to be 500 per annum at most.

Based on these considerations, we estimate that a maximum of 3,000 ships can be retrofitted with EGCSs annually.

C.6 Other constraints

A large number of studies have shown that there are barriers in the shipping sector to the uptake of cost-effective measures (see e.g. (CE Delft ; Marena Ltd. ; D.S. Lee, 2012); (Maddox consulting, 2012); (Eide, et al., 2011); (UCL, 2015)). While these studies refer to energy efficiency measures, the underlying causes for the barriers are general so the barriers probably also exist for EGCSs.

CE Delft et al. (2012) summarises the barriers as follows:

1. A split incentive because a shipowner has to invest in the EGCS while the charterer pays for the fuel. In the case of fuel efficiency measures, owners can earn a higher charter rate for a more fuel efficient ship in most market conditions but the additional amount is not always sufficient to pay for the implemented measures. The fact that owners are only able to recoup a share of the benefits depends on two factors. First, micro-economic analysis shows that it is rational in an equilibrium market that the benefits

are shared between the supplier (i.e. the owner) and the consumer (i.e. the charterer). How large the share for each party is, depends on the price elasticity of demand and the price elasticity of supply. Both depend on market circumstances and are therefore variable. Second, in charter parties the risks of over- and underperformance of a ship are unevenly distributed. While owners bear the risk of underperformance, there is no risk to the charterer in case of overperformance. Both factors combined have the effect that shipowners who invest in EGCSs are able to earn back a share of the fuel benefits through higher charter rates. The remaining benefits are for the charterer.

2. Many shipping companies face financial constraints as a result of which their ability to invest is limited. In addition, there are often several projects competing for the investment budget, and some investments may be obligatory, e.g. for ballast water management.
3. Yards may be reluctant to implement new and innovative technologies, and they may be reluctant to include these technologies in their warranties. The reluctance varies considerably over yards.
4. As EGCSs are preferably installed when a ship is already in dry dock, and dry docks are planned on regular 4 to 6 year intervals, there may be a time lag between when a measure becomes cost-effective and its implementation.

The first barrier, the split incentive, is probably the most important one. CE Delft et al. (2012) estimates that 70-90% of the ships are on-time charters and therefore subject to this split incentive. Note, however, that there are also cases in which shipowners install EGCSs because a charterer requires them to do so. For energy efficiency technologies, CE Delft (2012) estimates that the split incentive results in about 25% of the cost-effective technologies not being implemented.

C.7 Conclusions

This study models the uptake of EGCSs by applying four filters: a cost-benefit analysis, regulatory constraints, technical and operational constraints, and the availability of EGCSs.

We find that EGCSs are cost-effective for the majority of ships with engines over 20 MW. The share of ships for which EGCSs are cost-effective increases for ship types with an average installed power between 5 and 20 MW. Below 5 MW, EGCSs are often only cost-effective for new buildings, if at all, at the assumed fuel prices.

The regulatory uncertainty about washwater discharges is currently increasing the uncertainty in cost-benefit analysis and as a result has a negative impact on the level of investments. If a decision is taken to require the use of fuels with a sulphur content of 0.50% m/m or less from 2020 onwards, this will reduce the impact of the regulatory uncertainty because more fuel will be consumed at the high sea where washwater discharges are only subject to the IMO washwater criteria and not to additional constraints. If the uncertainty continues to exist until 2020, we expect that ships will preferably install hybrid EGCSs.

Technical and operational constraints do not, in general, render the installation of EGCSs impossible. New ships can be designed to have EGCSs without sacrificing cargo space or stability. On existing ships, it appears that EGCSs space is most constrained on container ships. For our modelling purposes, we assume that EGCSs can only be retrofitted to container ships at the expense of 0.2% of cargo space. For small container ships, RoRo feeders and small RoPax vessels, the available power or space may be a constraint. In our modelling, we assume that these ships will not install EGCSs.

The availability of EGCSs is not a constraint. The capacity of yards to install EGCSs can be a constraint when demand exceeds the regular dry docking capacity of some 3,000 ships per year. Most installations can be carried out during regular dry dockings.

The uptake of EGCSs will be affected by the split incentive between owners and charterers, the financial constraints that some shipping companies face, and by inexperience of some yards. We model this as to reduce demand by 50%.

In sum, our analysis points to:
- The installation of EGCSs on ships will continue at the current rate until 2017.
- Provided that IMO decides in 2017 to keep the date for the implementation of the 0.50% sulphur limit at 2020, we expect that shipowners will make the following investment decisions:
    - Small container ships and RoRo feeders will not install EGCSs because of power limitations.
    - If the regulatory uncertainty is reduced, ships will generally opt for open loop EGCSs, if it prevails, they will opt for hybrid EGCSs.
    - 75% of the ships built in 2018 and 2019 will be fitted with an EGCS if it is cost-effective to do so.
    - Of the container ships for which it is cost-effective to do so, 75% will retrofit EGCSs during their regular dry docking. The cost-effectiveness of EGCSs for container vessels takes into account that cargo space needs to be sacrificed.
    - 75% of the other ships for which an EGCS is cost-effective, will retrofit EGCSs during regular dry docking.
    - The total number of ships which install EGCSs will not exceed 3,000 per year.
- Should IMO decide to keep the date for implementation in 2020 prior to 2017, this will only have a limited impact on the uptake of EGCSs because installation before 2018 would imply that there is hardly a return on investment for more than two years.
- Should IMO decide after 2017, this will reduce the number of EGCSs installed because the lead time and yard capacity will become limiting factors.
- Installations will be scheduled as closely as possible to the implementation date of the sulphur limit. We expect installations to begin in the second half of 2018.

In total, we expect about 3,800 ships to be installed with EGCSs in the base case on 1 January 2020, provided that a decision is taken in or before 2017. Collectively, they consume 36 million tonnes of HFO with a sulphur content of more than 0.50% m/m.

The number of ships that are projected to be equipped with EGCSs by 2020 is much higher than the number in the current fleet, which is an order of magnitude smaller (CE Delft, 2015b). The main reason for this difference is that currently, EGCSs are only cost-effective for ships that consume a large share of their fuel in ECAs. These are often smaller ships like container feeders, shuttle tankers, ferries, et cetera, for which EGCSs are relatively expensive. A global sulphur limit will make EGCSs a cost-effective compliance method for ocean going vessels with larger engines and comparatively cheaper EGCSs.

C.8 Sensitivity analysis

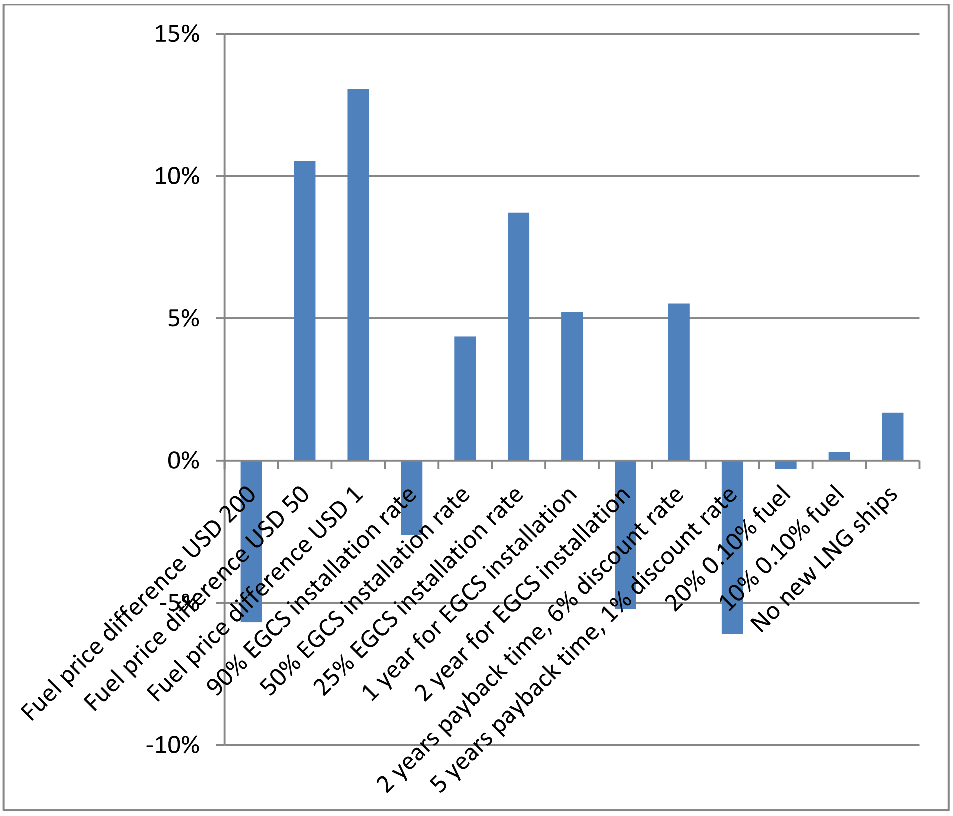
A sensitivity analysis was conducted in order to assess the impact of different assumptions relating to the uptake of EGCSs on the demand for fuel oil.
The following situations were modelled:

- Fuel price difference of USD 50 between 0.50% fuel and HFO instead of USD 129. A smaller fuel price difference results in a reduction in the number of ships for which EGCSs are cost-effective and consequently a lower uptake of EGCSs. Hence, the share of HFO in the fuel mix will be reduced and the share of fuels with a sulphur content of 0.50% m/m or less will be increased relative to the base case.
- Fuel price difference USD 1 between 0.50% fuel and HFO instead of USD 129. This has similar impacts as above, but the impacts are larger.
- 90% of ships for which EGCSs are cost-effective and which have an opportunity to install them, will install them, instead of 75%. This results in a larger number of ships with EGCSs and therefore to an increase in the demand for HFO and a decrease in the demand for fuels with a sulphur content of 0.50% m/m or less.
- 50% of ships for which EGCSs are cost-effective and which have an opportunity to install them, will install them, instead of 75%. This results in a smaller number of ships with EGCSs and therefore a decrease in the demand for HFO and an increase in the demand for fuels with a sulphur content of 0.50% m/m or less.
- 25% of ships for which EGCSs are cost-effective and which have an opportunity to install them, will install them, instead of 75%. This has a similar effect as the previous, only larger.
- One year for installation of EGCSs instead of two. If due to a late decision on the implementation date or a lower availability of yards or EGCSs, there is only one year to install EGCSs and not two, this will reduce the number of ships fitted with EGCSs in 2020, decrease the demand for HFO and increase the demand for fuels with a sulphur content of 0.50% m/m or less.
- Three years for installation of EGCSs instead of two. This has the opposite effect as above.
- Two years payback time instead of three for evaluating retrofit investment proposals and a 6% discount rate instead of 3% for evaluating a newbuilding investment proposal. If shipping companies use more stringent criteria to evaluate investment proposals, fewer ships would be equipped with EGCSs, the demand for HFO would be lower and the demand for fuels with a sulphur content of 0.50% m/m or less would be higher.
- Five years payback time instead of three for evaluating retrofit investment proposals and a 1% discount rate instead of 3% for evaluating a newbuilding investment proposal. This would have the opposite effect as the previous one.
- 15% fuel used in ECAs and in engines and equipment that require low-sulphur fuels instead of 9.6%. If the share of fuel used in ECAs increases and the amount of 0.10% distillates used for other purposes such as in auxiliary engines remains constant, the demand for fuel with a sulphur content of 0.10% m/m or less will increase. Since this does not directly affect the uptake of EGCSs, most of this increase will come at the expense of the demand of fuel with a sulphur content between 0.10 and 0.50%.

– 5% fuel used in ECAs and in engines and equipment that require low-sulphur fuels instead of 9.6%. This has the opposite effect as described above.
– No new LNG ships. For newbuildings, LNG and EGCSs are alternative ways to comply with a sulphur limit. In our model, this choice is exogenous, however, less LNG results in a higher demand for petroleum-derived fuels, and because the cost-effectiveness of EGCSs nor the other factors that affect their uptake changes, it results predominantly in a higher demand for fuels with a sulphur content of 0.50% m/m or less.
– LNG uptake doubled. This has the opposite effect as described above.

Figure 16 shows the results of the sensitivity analysis. The assumptions with the largest impact on the demand for compliant fuels are the price difference between conventional and compliant fuels, and the share of ships that install EGCSs when it is in their best interest to do so. A negligible fuel price difference would result in a 13% higher demand for compliant fuels; a much lower share of ships that install EGCSs in a 9% higher demand.

Figure 16 **Change in demand for fuels with a sulphur content of 0.50% m/m or less**

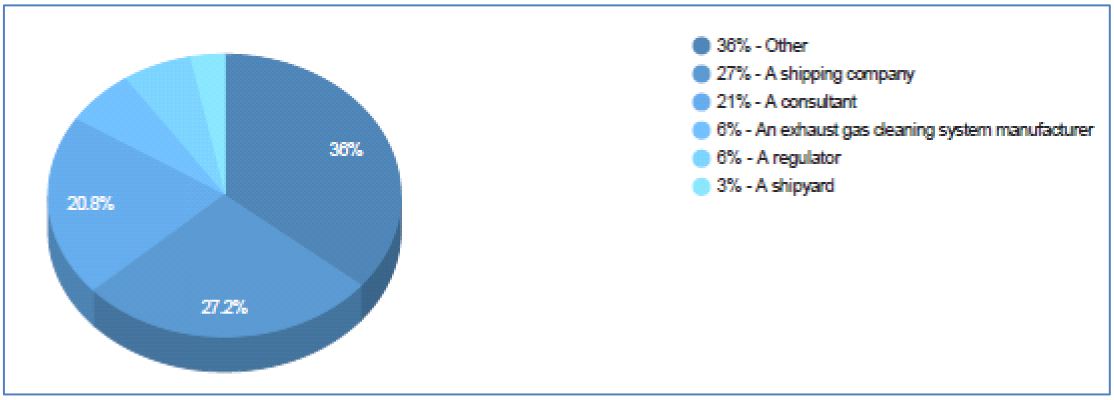


C.9 Stakeholder consultation

The preceding sections are based on a literature review and a stakeholder consultation. The stakeholder consultation comprised in-depth interviews with shipping companies, equipment manufacturers, yards and regulators (see Annex F for an overview) and an internet survey.

In order to validate the assumptions on EGCS uptake, an internet survey has been designed and sent to several stakeholders. This survey has started on the 13th of January 2016 and ended on the 19th of February 2016. In total, 661 respondents have opened the survey of which 81 have partially completed the survey and 131 have fully completed the survey. The type of respondents that have fully completed the survey is shown in Figure 17.

Figure 17 Overview type of respondents online survey



The questionnaire consisted of 21 questions on the assumptions previously discussed in this annex. In general, the percentage of respondents that agree with the assumptions is larger than the percentage of respondents that disagree. In addition, a significant part of the respondents do not have an opinion on the assumptions. The responses to specific questions have been included in the previous sections.

Finally, assumptions on the availability of EGCSs are discussed. The eight assumption discussed is the production capacity of EGCSs. The respondents that disagree often state that ship yard capacity might be an issue.
No information sources have been provided to prove these statements.
The last assumption discussed is the installation capacity of EGCSs.
The respondents that disagree often state that yard availability could be an issue. No information sources have been provided to prove these statements.

Annex D Updated calculations energy demand projection model in 2020

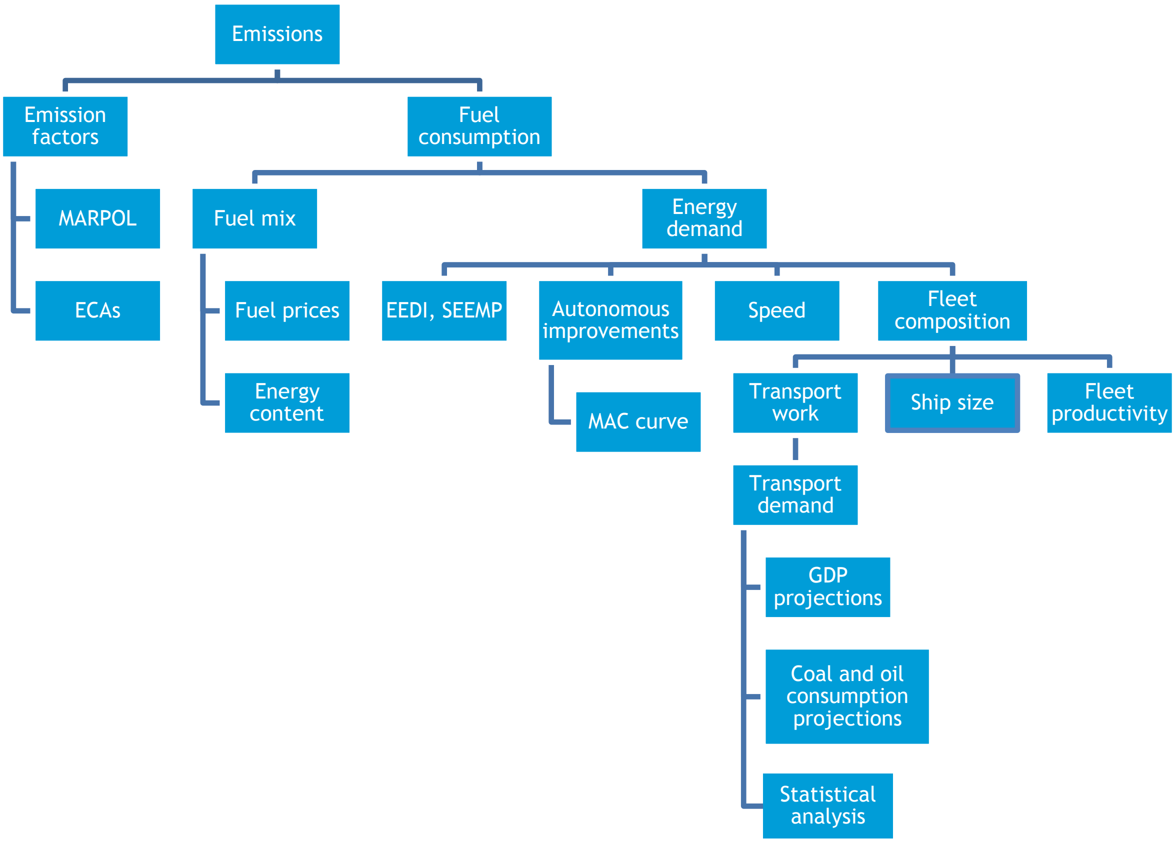
D.1 Model description

This section presents a short description of the model used to project maritime energy demand. It is based on the Third IMO GHG Study 2014, Section 3.2. A detailed description can be found in the Third IMO GHG Study 2014, Annex 7.

The model used to project emissions starts with a projection of transport demand, building on long term socio-economic scenarios developed for the IPCC (see Section D.1.1). Taking into account developments in fleet productivity (see Section D.1.3) and ship size (see Section D.1.4), it projects the fleet composition in each year. Subsequently, it projects energy demand, taking into account regulatory and autonomous improvements in efficiency (see Section D.1.5).

A schematic presentation of the emissions projection model is shown in Figure 18.

Figure 18 Schematic presentation of the emissions projection model



D.1.1 Base scenarios

Scenario construction is necessary to gain a view of what may happen in the future. In the Second IMO GHG Study 2009, background scenarios (SRES - see Section 3.1.1) were chosen from the IPCC's activities, since the 2009 study was primarily about emissions; it made sense to make the emissions scenarios consistent with other associated climate projections. Here, this study basically follows the same logic; while other 'visions' of the future are available, and arguably equally plausible, since the overall subject of the present study is emissions, this study follows the earlier precedent and uses approaches and assumptions that will ultimately allow the projections to be used in climate studies. Moreover, data from climate projections studies include the essential socio-economic and energy drivers that are essential for the emissions projections made here.

After its 4th Assessment Report, published in 2007 (IPCC, 2007a), the IPCC decided to update the projections to be used in its next Assessment Report (IPCC 5th Assessment Report 2011/15) (IPCC, 2014). The scenarios are called representative concentration pathways (RCPs). Their naming and use are best explained in the quote below:

The name 'representative concentration pathways' was chosen to emphasise the rationale behind their use. RCPs are referred to as pathways in order to emphasise that their primary purpose is to provide time-dependent projections of atmospheric greenhouse gas (GHG) concentrations. In addition, the term pathway is meant to emphasise that it is not only a specific long term concentration or radiative forcing outcome, such as a stabilisation level, that is of interest, but also the trajectory that is taken over time to reach *that outcome. They are representative in that they are one of several different scenarios that have similar radiative forcing and emissions characteristics' (IPCC Expert Meeting Report, 2007)* (IPCC, 2007b)

A useful summary and guide to the origin and formulation of the RCP scenarios is provided by Wayne (Wayne, 2013). The 'concentration' refers to that of CO_2 and the 'pathways' are 'representative' of possible outcomes of energy, population, policy and other drivers that will ultimately determine the concentration of CO_2 in the atmosphere. There are four main RCPs in use, detailed in Table 157.

Table 157 Descriptions and sources of representative concentration pathways

RCP	Description	Source references	Model
RCP2.6 (or 3PD)	Peak in radiative forcing at ~3 W/m2 before 2100 and decline	(Van Vuuren , et al., 2006) (Van Vuuren, et al., 2007)	IMAGE
RCP4.5	Stabilisation without overshoot pathway to 4.5 W/m2 at stabilisation after 2100	(Clarke, et al., 2007) (Wise, et al., 2009)	GCAM
RCP6.0	Stabilisation without overshoot pathway to 6 W/m2 at stabilisation after 2100	(Hijioka, et al., 2008)	AIM
RCP8.5	Rising radiative forcing pathway leading to 8.5 W/m2 in 2100.	(Riahi, et al., 2007)	MESSAGE

The numbers associated with the RCPs (2.6-8.5) simply refer to resultant radiative forcing in W/m^2 by 2100. Further technical details of the RCPs are given in Moss (Moss, et al., 2010). The RCPs cover a range of ultimate temperature projections by 2100 (i.e. global mean surface temperature increases over the pre-industrial period from GHGs), from around 4.9°C (RCP8.5) to 1.5°C in the most optimistic scenario (RCP2.6 or RCP3PD, where PD refers to peak and decline).

These RCPs are used to project shipping coal and liquid fossil fuel transport work, on the basis of a historical correlation with global coal and oil consumption (see Section 3.2.3), using the IAM energy demand projections of different fuel/energy types (EJ/yr). A set of GDP projections from the associated five SSP scenarios (see (Kriegler, et al., 2012)) was used for non-fossil fuel transport projections (see Section 3.2.3).

The five SSPs each have different narratives (Ebi, et al., 2014) and are summarised in Table 158.

Table 158 Short narratives of shared socio-economic pathways

SSP number and name	Short narrative
SSP1: Sustainability	A world making relatively good progress towards sustainability, with ongoing efforts to achieve development goals while reducing resource intensity and fossil fuel dependency. It is an environmentally aware world with rapid technology development and strong economic growth, even in low-income countries.
SSP2: Middle of the road	A world that sees the trends typical of recent decades continuing, with some progress towards achieving development goals. Dependency on fossil fuels is slowing decreasing. Development of low-income countries proceeds unevenly.
SSP3: Fragmentation	A world that is separated into regions characterised by extreme poverty, pockets of moderate wealth and a large number of countries struggling to maintain living standards for a rapidly growing population.
SSP4: Inequality	A highly unequal world in which a relatively small, rich, global elite is responsible for most GHG emissions, while a larger, poor group that is vulnerable to the impact of climate changes contributes little to the harmful emissions. Mitigation efforts are low and adaptation is difficult due to ineffective institutions and the low income of the large poor population.
SSP5: Conventional development	A world in which development is oriented towards economic growth as the solution to social and economic problems. Rapid conventional development leads to an energy system dominated by fossil fuels, resulting in high GHG emissions and challenges to mitigation.

This presented the problem of how to combine the RCPs with the SSPs and guidance was taken from Kriegler (Kriegler, et al., 2012), as follows.

In principle, several SSPs can result in the same RCP, so in theory many BAU scenarios can be developed. However, in order to limit the number of scenarios, while still showing the variety in possible outcomes, it was decided to combine each SSP with one RCP, under the constraint that this combination is feasible. The SSPs are thus aligned with the RCPs on the basis of their baseline warming. Increased mitigation effort would potentially result in less fossil fuel transport, probably somewhat lower economic growth until 2050 and therefore probably lower transport demand and maritime emissions.

This procedure has resulted in the following scenarios:
- RCP 8.5 combined with SSP5;
- RCP 6 combined with SSP1;
- RCP 4.5 combined with SSP3;
- RCP 2.6 combined with SSP4/2.

In all the IPCC's work on future scenarios of climate and its impacts, it has never assumed a BAU underlying growth scenario. The IPCC has always argued that all scenarios are equally likely, ergo no overall BAU scenario exists.

D.1.2 Transport demand projections

Transport work data (in billion tonne miles per year) were kindly provided for the years 1970-2012 by UNCTAD. The categories considered were crude oil and oil products (combined), coal bulk dry cargo, non-coal bulk dry cargo (iron ore, coal, grain, bauxite and aluminium and phosphate, all combined) and other dry cargo (essentially considered as container and other similar purpose shipping). The data were for international shipping only. Transport work (i.e. tonne miles) as opposed to the absolute amount transported (tonnes), is considered to be a better variable to predict transport demand and emissions. However, this assumes that average hauls remain constant: this, is in fact borne out by the data and the two variables correlate significantly with an R^2 value of > 0.95.

Cargo types were treated separately, as it is evident from the data that they are growing at different rates and subject to different market demands.

Thus, as a refinement to the approach taken in the Second IMO GHG Study 2009 (IMO, 2010), the current study has developed the methodology of CE Delft (2012), which considered different ship types and has gone a step further by decoupling the transport of fossil fuel (oil and coal products) from GDP, as in the RCP/SSP scenarios in which fossil fuel use is decoupled from economic development.

In order to predict ship transport work (by type, or total), the general principle is to look for a predictor variable that has a meaningful physical relationship with it. In previous scenario studies, global GDP has been used as a predictor for total ship transport work, in that it has a significant positive statistical correlation, and is also meaningful in the sense that an increase in global GDP is likely to result in an increase in global trade and therefore ship transport of goods.

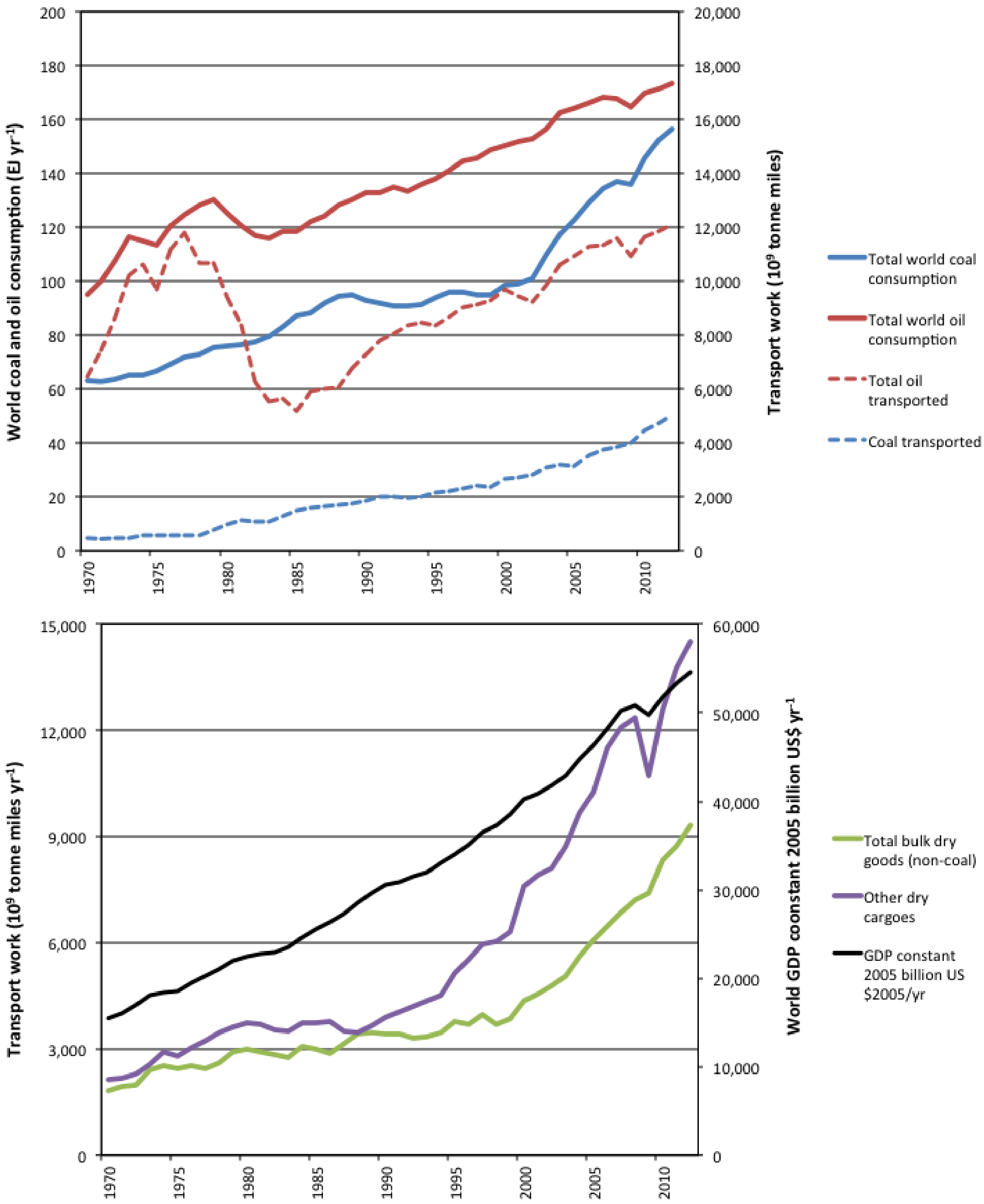
If an independent assessment of the predictor variable (e.g. GDP) is available for future years, this allows prediction of ship transport work. It assumes that such a physical relationship is robust for the future as it has been for the past. Previously, a linear assumption has been made, i.e. a linear regression model has been used between the ratio of historical transport work to historical GDP against time. In this study, this assumption has been improved by the use of a non-linear model, commonly used in economics, that assumes classical emergence, growth and maturation phases.

However, the assumption of a historical relationship between coal and oil transport by shipping and GDP inherently means that GDP growth and fossil-fuel use will remain tightly coupled in the future, i.e. that with increased economic growth, it is not possible to limit fossil fuel use. This clearly does not reflect certain desired policy and environmental outcomes, where a decrease in fossil-fuel dependence and an increase in GDP can be achieved.

In order to overcome this, this study has investigated the relationship between historical ship transported coal and oil and historical global coal and oil consumption. This relationship has been found to be as robust as that as between historical coal and oil transport work and historical GDP ($r2 > 0.9$) and is arguably a better physical relationship than between fossil fuel transported by shipping and GDP. The RCP scenarios have provided projections of fossil fuel consumption, split between coal and oil. This conveniently allows us to use these predictor variables to determine potential future ship transport of coal and oil but decoupled from GDP. Other ship transported goods and products remain predicted by independent future GDP assessments provided by the RCPs.

In all cases of ship-transported products, the non-linear Verhulst regression model (with S-shaped curve) is used to reflect more realistic market behaviour rather than continued linear relationships. The historical data on transport work (by type) and demand and GDP are shown in Figure 19.

Figure 19 Historical data on world coal and oil consumption, coal and oil transported (upper panel), total (non-coal) bulk dry goods, other dry cargoes and global GDP (lower panel)



Predicted proxy data of (separate) coal and oil demand and GDP were provided by the RCP/SSP scenarios and the associated underlying integrated assessment models (IAMs). In one case (RCP6.0) fossil energy demand data could not be obtained and data from the IAM GCAM were used.

D.1.3 Fleet productivity

For the emissions projection, the development of the tonnage of the different ship types is determined by a projection of the ships' productivity, defined as transport work per deadweight tonne. More precisely, the fleet is assumed to grow if, given the projected productivity, the expected transport demand cannot be met by the fleet. On the other hand, if, given the projected productivity, the expected transport demand could be met by a smaller fleet, the active fleet is not assumed to decrease. This means that ships are assumed to reduce their cargo load factor, i.e. become less productive, rather than being scrapped or laid up or reducing their speed.

The projection of ship productivity is based on the historical productivity of the ship types. For all ship types, the 2012 productivity of the ship types is lower than the long term historical average. This is assumed to be caused by the business cycle, rather than by structural changes in the shipping market; therefore, this study applies a future productivity development that converges towards the ship type's average productivity, reverting back to the 25-year[2] mean value within ten years, i.e. until 2022.

The ship productivity indices used in the emissions projection model, which can be specified per five-year period, are given in Table 159.

Table 159 Ship type productivity indices used in emissions projection model

	2012	2017	2022-2050
Liquid bulk vessels	100	113	125
Dry bulk vessels	100	102	104
Container ships	100	109	118
General cargo vessels	100	109	118
Liquefied gas carriers	100	106	113
All other vessels	100	100	100

Note that in this study, projections beyond 2020 are not used.

D.1.4 Ship size development

In the emissions projection model, ship types are divided into the same ship size categories as in the emissions inventory model. For the emissions projection, the future number of ships per size category has to be determined.

The distribution of the ships over their size categories can be expected to change over time according to the number of the ships that are scrapped and enter the fleet, as well as their respective size.

In the emissions projection model it is assumed that total capacity per ship type meets projected transport demand, that all ships have a uniform lifetime of 25 years and that the average size of the ships per size category will not change compared to the base year 2012, while the number of ships per bin size will.

The development of the distribution of the vessels over the size categories until 2050 is determined based on a literature review, taking into account historical developments in distribution, expected structural changes in the

2 Due to a lack of historical data, for container vessels and liquefied gas vessels we take the average of the 1999-2012 period, i.e. a 13-year period.

markets and infrastructural constraints. In Table 160 and Table 161, 2012 distributions and expected distributions for 2050 are presented.

Table 160 2012 distribution and expected distribution 2050 of container and LG carriers over bin sizes

Ship type	Bin size	Distribution in terms of numbers	
		2012	2050
Container vessels	0-999	22%	22%
	1,000-1,999 TEU	25%	20%
	2,000-2,999 TEU	14%	18%
	3,000-4,999 TEU	19%	5%
	5,000-7,999 TEU	11%	11%
	8,000-11,999 TEU	7%	10%
	12,000-14,500 TEU	2%	9%
	14,500 TEU +	0.2%	5%
Liquefied gas carriers	0-49,000 m^3	68%	32%
	50,000-199,999 m^3	29%	66%
	> 200,000 m^3	3%	2%

Note that in this study, projections beyond 2020 are not used.

Table 161 2012 distribution and expected distribution 2050 of oil/chemical tankers and dry bulk carriers over bin sizes

Ship type	Size bins (dwt)	Distribution in terms of numbers	
		2012	2050
Oil/chemical tankers	0-4,999	1%	1%
	5,000-9,999	1%	1%
	10,000-19,999	1%	1%
	20,000-59,999	7%	7%
	60,000-79,999	7%	7%
	80,000-119,999	23%	23%
	120,000-199,999	17%	17%
	200,000+	43%	43%
Dry bulk carriers	0-9,999	1%	1%
	10,000-34,999	9%	6%
	35,000-59,999	22%	20%
	60,000-99,999	26%	23%
	100,000-199,999	31%	40%
	200,000-+	11%	10%

Note that in this study, projections beyond 2020 are not used.

For the other ship types the 2012 size distribution is presumed not to change until 2020.

D.1.5 EEDI, SEEMP and autonomous improvements in efficiency

The projection of the future emissions of maritime shipping requires projecting future developments in the fleet's fuel efficiency. In the period up to 2030, this study distinguishes between market-driven efficiency changes and changes required by regulation, i.e. EEDI and SEEMP. Market-driven efficiency changes are modelled using a MACC, assuming that a certain share of the cost-effective abatement options is implemented. In addition, regulatory requirements may result in the implementation of abatement options irrespective of their cost-effectiveness. Between 2030 and 2050, there is little merit in using MACCs, as the uncertainty about the costs of technology and its abatement potential increases rapidly for untested technologies. In addition, regulatory improvements in efficiency for the post-2030 period have been discussed but not defined. Therefore this study takes a holistic approach towards ship efficiency after 2030.

Our MACC is based on data collected for IMarEST and submitted to the IMO in MEPC 62/INF.7. The cost curve uses data on the investment and operational costs and fuel savings of 22 measures to improve the energy efficiency of ships, grouped into fifteen groups (measures within one group are mutually exclusive and cannot be implemented simultaneously on a ship). The MACC takes into account that some measures can only be implemented on specific ship types. It is also assumed that not all cost-effective measures are implemented immediately but that there is a gradual increase in the uptake of cost-effective measures over time.

The EEDI will result in more efficient ship designs and consequently in ships that have better operational efficiency. In estimating the impact of the EEDI on operational efficiency, this study takes two counteracting factors into account. First, the current normal distribution of efficiency (i.e. there are as many ships below as above the average efficiency, and the larger the deviation from the mean, the fewer ships there are) is assumed to change to a skewed distribution (i.e. most ships have efficiencies at or just below the limit, and the average efficiency will be a little below the limit value). As a result, the average efficiency improvement will exceed the imposed stringency limit. Second, the fact that most new-build ships install engines with a better specific fuel consumption than has been assumed in defining the EEDI reference lines is also taken into account. The result of these two factors is that operational improvements in efficiency of new ships will exceed the EEDI requirements in the first three phases but will lag behind in the third.

D.1.6 Energy density of marine fuels

In order to calculate the mass of fuel from the projected energy demand, the model uses energy density values as shown in Table 162.

Table 162 Energy density of marine fuels

Fuel type	Energy density (GJ/tonne)
HFO	39.5
biofuel	24.7
LNG	48.5
MDO	42

Source: Gätjens 2012.

D.2 Plausibility checks for the model

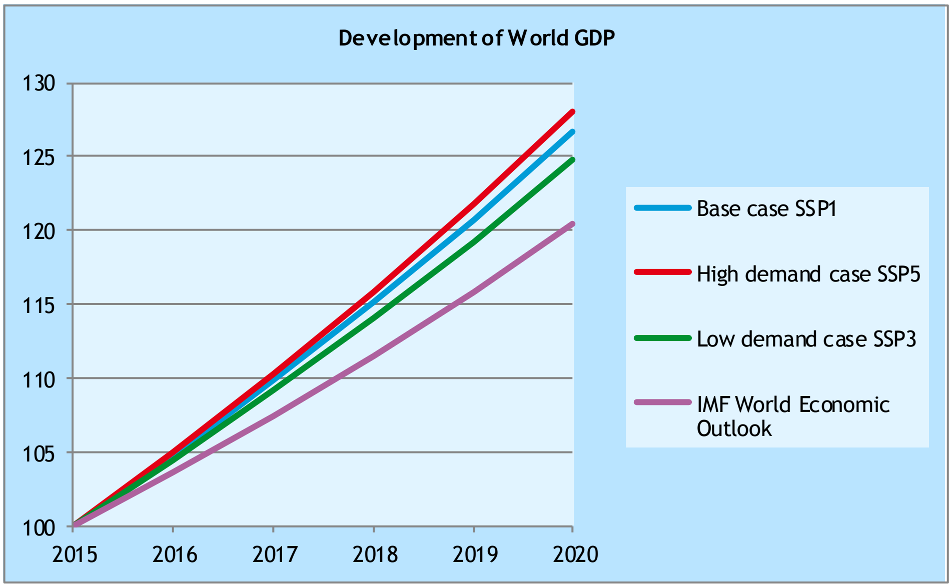
The development of total transport demand (billion ton miles) for the period 2012-2015 in the energy demand projection model (IMO, 2014) was compared to the development as reported by UNCTAD in the Review of Maritime Transport.

Figure 20 **Growth in world seaborne trade 2012-2015 (billion tonnes miles) from Review of Maritime Transport 2015**

This comparison shows that the growth in transport demand was very similar to that assumed in the base case scenario.

Additionally, the development in the World GDP in the scenarios from the energy demand projection model for the period 2015-2020 was compared to the development as predicted by IMF in the World Economic Outlook. Figure 21 shows the index (2015 = 100) of the development of the world GDP according to IMF and the three scenarios from the Third IMO GHG Study 2014 (IMO, 2014).

Figure 21 **Development of World GDP 2015-2020 from IMF World Economic Outlook**



This shows that the world GDP development in the scenarios is somewhat higher than predicted by IMF.

When the checks on the development of transport work and world GDP projections are combined, a trend of the development of transport work can be derived. For this analysis it was assumed that an increase of the world GDP of 1% for 2015-2020 leads to an increase of transport work of 0.96% (which is in line with the model assumptions). The result of this assessment is shown in Figure 22.

Figure 22 Development of transport work (index 2012=100) plausibility check according to UNCTAD and world GDP projections

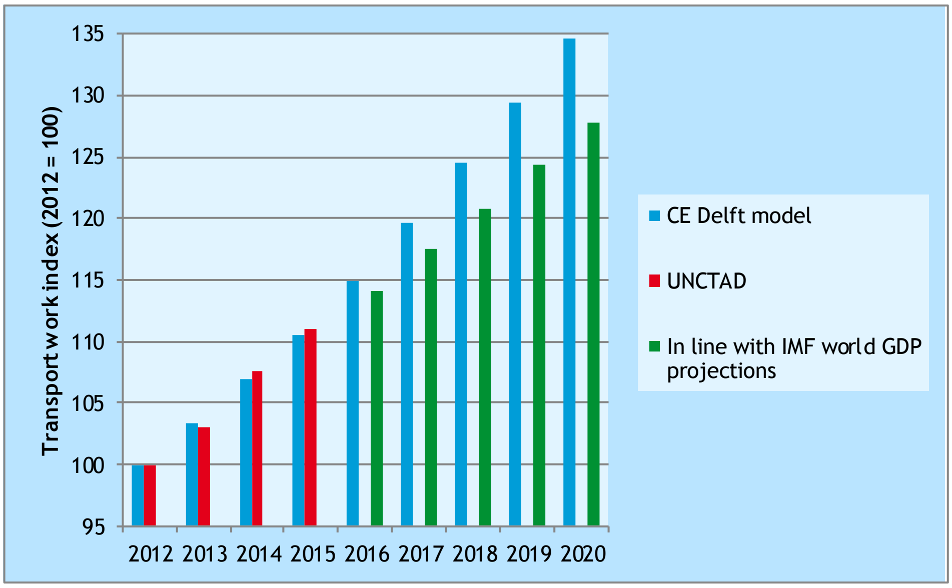


Table 163 shows both the total fleet and the ships that were built in 2012 or later according to Clarksons World Fleet Register. The rate of fleet renewal is between 3-8% per year, and weighted averaged over the various ship types the rate of fleet renewal for nine years would be around 41%.

Table 163 Rate of fleet renewal based on World Fleet Register by Clarksons

Ship type	Total fleet	Built 2012 and later (4 years)	% new ships
Tankers	13,718	1,587	12%
Chemical	4,577	617	13%
Bulkers	10,689	3,296	31%
LNG	438	81	18%
LPG	1,341	227	17%
Containers	5,239	807	15%
RoRo&pcc	2,051	235	11%

In the scenarios that were used in the Third IMO GHG Study 2014, the following rate of fleet renewal was calculated (Table 164). Only the fleet without miscellaneous ships was observed.

Table 164 Rate of fleet renewal according to three scenarios in the energy demand projection model

Scenario	Total ships in 2020 (excl. miscellaneous)	New ships in 2020 (built after 2012) (excl. miscellaneous)	% new ships
Base case	69,733	31,170	45%
High case	71,417	32,897	46%
Low case	68,494	29,887	44%

The rate of fleet renewal in the scenarios is somewhat higher than according to Clarksons, but seems realistic and consistent with recent developments.

Conclusion
This plausibility check shows that the energy demand of maritime transport in 2015 is very likely to be in close agreement with the modelled energy demand because the share of new ships as well as the amount of transport work are close the modelled values. In the coming years, economic growth and by implication transport demand growth may be lower than projected in the model if the IMF forecasts are realised. This suggests that the energy demand projections and fuel projections are more likely to be an overestimate than an underestimate of the 2020 energy demand. Still, we consider the differences to be small enough to continue to use the base case scenario of the Third IMO GHG Study 2014.

The scenarios were not adjusted for recent trends in transport demand, world GDP or fleet renewal rates. The recent developments seem to be consistent with the assumed trends in the different scenarios.

D.3 Model assumptions for operating speed and energy intensity out to 2020

As shown in the Third IMO GHG Study, variations in ship operating speeds (average speeds sailed on a passage or voyage) can create significant differences in ship energy efficiency and therefore carbon intensity. As noted in the Third IMO GHG Study, one of the consequences of the market conditions that evolved over the period 2007-2012 was a widespread take-up of slow steaming, which helped to control the rate of shipping's energy demand and emissions growth.

This historical observation of the significance and variability in operating speed demonstrates the importance of a robust consideration of how operating speeds might change over the modelling period in this study and how they might, in turn, influence both the total demand for fuels and the breakdown of this into demands for different types of fuel.

This study uses an analysis of the variability during the period 2007-2012, using data taken from the Third IMO GHG study, in order to inform a set of assumptions for possible scenarios for the future. The final assumptions are listed in Section 4.2.3, the detailed analysis and reasoning corresponding to why both a further decrease or an increase in operating speed is possible is laid out below.

During the period 2007-2012, the Third IMO GHG Study measured variations in both fleet composition (number of ships of different types and sizes), average design speeds (some reducing, some increasing), and operating speeds (average at sea speeds). Table 165 lists the data for the different categories of ship type and size considered. Whilst some variation in design speeds can be observed over the time period, the dominant change is in operating speed and for the mostly small variations in design speed to first approximation this operating speed trend can be taken in isolation. As validated through the QA and QC section of the Third IMO GHG Study, for levels of at sea speed variability observed during this period, a good approximation for the impact of such variation in operating speed on fuel consumption is the cubic relationship (See Third IMO GHG study Annex 1 and Annex 3). A slower ship does less transport work (if all else is equal, this is a direct linear relationship between ship speed and transport work), and therefore the consequent energy intensity variations can be approximated as quadratic in operating (at sea) speed. Using this, Table 165 also presents the consequence of the operating speed variation in energy intensity.

Table 165 shows that there is significant operating speed reduction during this period depending on the ship type considered. For example container ships were on average reducing operating speeds by a greater margin than dry bulk carriers. This presents a challenge when estimating aggregate average variations appropriate for the scale and resolution of the modelling carried out in this study. To overcome this, all the data for different ship types are used in CO_2 weighted average change calculations for the period 2007-2012:
- fleet CO_2 weighted average speed change 2007-2012 = 11% reduction;
- fleet CO_2 weighted average energy intensity change 2007-2012 = 21% reduction.

After the start of the recession, speeds have continued to vary. For example, the CO_2 weighted average changes between 2009 and 2012 were:
- fleet CO_2 weighted average speed change 2009-2012 = 9% reduction;
- fleet CO_2 weighted average energy intensity change 2009-2012 = 17% reduction.

Having established quantitatively what values correspond to the period 2007-12 and 2009-2012, the next consideration is what this data indicates the possible variability might be out to 2020. Relative to the 2012 baseline used in this study's modelling, its clearly possible for ship speeds to increase (e.g. similar to their historical values), or possible for them also to decrease. Both changes having consequences on energy intensity. Arguments for either situation are reasoned below:

Operating speeds decrease further 2012 to 2020 – this would be consistent with a continuation of depression in many of the shipping markets, and the emphasis on energy efficiency that has resulted from increased regulatory attention to energy efficiency and GHG emissions. Depending on the machinery specification, a ship's operating speed has a lower limit determined by mechanical considerations (typically maintenance limits, control system limits on the main engine). So for a scenario that projects further decrease in speeds, this lower-bound limit on operating speed needs to be considered, or design speeds would also need to reduce. For older engines this operating limit can correspond to points as high as 40% MCR, or on newer engines this could be as low as 8% MCR. Table 17 in the Third IMO GHG Study provides some insight into how close, in 2012, the ships were to these lower limits and therefore what scope there is for further operating speed reduction without changes required in design speed. The table shows that in the case of tankers and bulk carriers, there is still plenty of scope for average operating speed reduction. In the container ship fleet, where in 2012 the average operating %MCR was estimated to be closer to 30%, there is less scope, but with the evolution in machinery technology and evidence of reducing design speeds in this fleet (IMO MEPC 69 INF 29), modest further operating speed reductions are certainly possible.

Operating speed increase between 2012 and 2020 – this scenario would be consistent with some recovery in several of the shipping markets, with increases in freight rates and tighter supply which could in turn create an incentive to increase operating speeds (as a means to increase profits). With only modest changes observed in design speeds from 2007 to 2012 and historical precedent for operatings at average speeds close to design speed, this scenario is equivalent to the fleet returning to the states (speeds and energy intensities) observed in 2007. For markets to recover fully in the timescale to 2020, given the historic lows observed recently in many shipping markets (BDI (or example), is challenging, but some recovery and therefore some speed increase, especially considering relative oil price reductions between 2012 and 2016, is certainly possible.

Table 165 Design and operating speeds in 2012 and 2007

Ship type	Size category	2012		2009		2007	
		Average 'design' speed (knots)	Average at sea speed (knots)	Average 'design' speed (knots)	Average at sea speed (knots)	Average 'design' speed (knots)	Average at sea speed (knots)
Bulk carrier	0-9999	11.62	9.41	11.83	10.17	11.58	10.32
Bulk carrier	10000-34999	14.77	11.38	15.26	11.98	14.62	12.18
Bulk carrier	35000-59999	15.26	11.77	15.42	12.57	14.90	12.71
Bulk carrier	60000-99999	15.35	11.91	15.12	13.01	14.87	12.96
Bulk carrier	100000-199999	15.28	11.74	15.48	13.28	14.77	12.82
Bulk carrier	200000-+	15.72	12.21	16.44	13.00	15.55	11.50
Chemical tanker	0-4999	11.95	9.81	12.02	10.33	12.02	10.58
Chemical tanker	5000-9999	13.41	10.59	14.32	11.47	13.83	11.85
Chemical tanker	10000-19999	14.12	11.68	15.34	12.47	15.27	12.95
Chemical tanker	20000-+	14.97	12.34	15.86	13.15	15.77	13.68
Container	0-999	16.51	12.38	16.87	13.22	16.74	13.26
Container	1000-1999	19.45	13.93	20.08	15.10	20.05	15.15
Container	2000-2999	22.17	14.99	22.37	16.83	21.89	16.82
Container	3000-4999	24.07	16.05	25.04	17.59	24.67	18.59
Container	5000-7999	25.12	16.26	26.05	19.24	26.35	20.55
Container	8000-11999	25.47	16.27	27.33	19.89	28.15	21.26
Container	12000-14500	28.90	16.13	26.00	17.40	26.00	20.55
Container	14500-+	25.01	14.85				
General cargo	0-4999	11.56	8.75	11.39	9.18	11.34	9.31
General cargo	5000-9999	13.57	10.13	13.93	10.87	13.92	11.37
General cargo	10000-+	15.84	12.01	16.46	12.62	15.78	12.94
Liquefied gas tanker	0-49999	14.17	11.87	14.10	12.21	13.94	12.39
Liquefied gas tanker	50000-199999	18.51	14.87	19.32	14.57	19.54	14.85
Liquefied gas tanker	200000-+	19.27	16.89	23.42	16.72	78.00	15.39
Oil tanker	0-4999	11.49	8.72	11.28	9.40	11.20	9.65
Oil tanker	5000-9999	12.57	9.13	12.99	9.93	12.95	10.34
Oil tanker	10000-19999	13.39	9.63	13.86	10.23	14.03	10.78
Oil tanker	20000-59999	14.84	11.71	15.61	12.38	15.38	12.68
Oil tanker	60000-79999	15.06	12.17	15.72	13.18	15.70	13.42
Oil tanker	80000-119999	15.25	11.61	15.67	12.87	15.29	13.35
Oil tanker	120000-199999	15.99	11.73	16.07	13.23	15.40	13.69

Ship type	Size category	2012		2009		2007	
		Average 'design' speed (knots)	Average at sea speed (knots)	Average 'design' speed (knots)	Average at sea speed (knots)	Average 'design' speed (knots)	Average at sea speed (knots)
Oil tanker	200000-+	16.00	12.48	16.48	14.25	15.96	14.56
Other liquids tankers	0-+	9.77	8.29	9.61	7.04	9.86	8.97
Ferry-pax only	0-1999	22.66	13.85	22.95	17.85	22.72	18.87
Ferry-pax only	2000-+	16.64	12.79	17.15	13.53	16.55	11.38
Cruise	0-1999	12.36	8.78	12.66	9.00	12.82	9.35
Cruise	2000-9999	15.99	9.93	16.09	11.02	15.71	10.88
Cruise	10000-59999	19.87	13.78	20.33	14.82	19.91	14.74
Cruise	60000-99999	22.16	15.69	22.35	16.07	22.83	16.40
Cruise	100000-+	22.67	16.44	23.54	16.84	22.90	16.90
Ferry-RoPax	0-1999	13.02	8.40	13.38	10.82	13.17	11.02
Ferry-RoPax	2000-+	21.58	13.87	21.99	17.01	21.53	17.41
Refrigerated bulk	0-1999	16.76	13.36	16.27	13.60	16.31	13.64
Ro-Ro	0-4999	10.73	8.78	11.55	9.70	11.65	10.18
Ro-Ro	5000-+	18.60	14.24	18.05	14.52	17.84	14.56
Vehicle	0-3999	18.28	14.24	20.06	14.82	17.55	14.91
Vehicle	4000-+	20.12	15.52	21.76	16.16	20.46	16.76
Yacht	0-+	16.51	10.73	16.73	12.17	16.58	12.64
Service - tug	0-+	11.83	6.65	12.00	7.82	11.89	8.63
Miscellaneous - fishing	0-+	11.52	7.44	11.47	8.84	11.44	9.74
Offshore	0-+	13.84	7.98	14.44	9.15	14.12	9.71
Service - other	0-+	12.78	7.86	12.37	8.83	12.22	9.38
Miscellaneous - other	0-+	12.69	7.26	13.05	9.01	12.59	8.70

D.4 Projected energy and fuel use

Table 166 shows the energy use per ship type in 2012 and the projected energy use in 2020 in the base, high and low cases.

Table 166 Energy use (PJ) per ship type for three scenarios in 2020

Ship type	2012	Base case	High case	Low case
Dry bulk	2,109	2,422	2,663	2,108
Liquid bulk	2,893	2,482	3,031	2,218
Unitized	4,371	5,448	6,132	4,826
Passenger	981	939	1,042	846
Miscellaneous	1,523	1,523	1,691	1,373
Total	11,877	12,814	14,559	11,370

Source: This study.

Note: Unitized comprises container ships, RoRo and general cargo ships.

Table 167 presents global and regional fuel demand for the low case, which assumes lower growth of transport demand, increased vessel operational efficiency and higher uptake of EGCSs and LNG. The demand for petroleum fuels with a sulphur content of 0.50% m/m or less is 15% lower than in the base case.

Table 167 Global marine fuel demand (2020) - low case

Sulphur (% m/m)	Petroleum-derived fuels			LNG
	<0.10%	0.10%-0.50%	>0.50%	
	In ECAs	Outside ECAs	Globally in combination with an EGCS	Globally
	Million tonnes per year			
Africa	2	10	1	0.7
Asia	15	93	16	3.4
Russia & CIS	1	6	2	2.0
Europe	8	46	9	1.3
Latin America	3	18	3	0.1
Middle East	1	4	4	1.9
North America	4	22	3	3.7
Global	33	198	38	13

Source: This report.

Table 168 shows projected marine fuel demand in 2020 in the high case. It assumes greater growth of transport demand, a reduction of vessel operational efficiency, fewer EGCSs and a lower uptake of LNG.
The demand for petroleum fuels with a sulphur content of 0.50% m/m or less is 24% higher than in the base case.

Table 168 Global marine fuel demand (2020) - high case

Sulphur (% m/m)	Petroleum-derived fuels			LNG
	<0.10%	0.10%-0.50%	>0.50%	
	In ECAs	Outside ECAs	Globally in combination with an EGCS	Globally
	Million tonnes per year			
Africa	2	14	0	0.6
Asia	23	136	6	3.1
Russia & CIS	1	9	1	1.8
Europe	11	67	3	1.2
Latin America	4	26	1	0.1
Middle East	1	6	1	1.8
North America	5	32	1	3.4
Global	48	290	14	12

Source: This report.

D.5 Detailed results of energy projection and number of ships per scenario

Results per scenario

In Table 169, Table 170 and Table 171 the energy demand projection model results are presented for the base case, high case and low case. Each table shows the energy use per ship type and fuel type, and the number of ships per ship type and the share that was built in or after 2012.

Table 169 Energy use (PJ) and number of ships in 2020 for base case

Results	Dry bulk	Liquid bulk	Unitized	Passenger	Miscellaneous	Total
Energy use						
Total	2,422	2,482	5,448	939	1,523	12,814
Number of ships						
Total ships	13,931	13,659	35,630	6,514	51,652	121,385
New ships (built after 2012)	6,846	3,870	18,376	2,084	16,529	47,705
% new	49%	28%	52%	32%	32%	39%

Table 170 Energy use (PJ) and number of ship in 2020 for high case

Results	Dry bulk	Liquid bulk	Unitized	Passenger	Miscellaneous	Total
Energy use						
Total	2,663	3,031	6,132	1,042	1,691	14,559
Number of ships						
Total ships	13,795	14,960	36,148	6,514	51,652	123,069
New ships (built after 2012)	6,697	5,209	18,914	2,084	16,529	49,433
% new	49%	35%	52%	32%	32%	40%

Table 171 Energy use (PJ) and number of ship in 2020 for low case

Results	Dry bulk	Liquid bulk	Unitized	Passenger	Miscellaneous	Total
Energy use						
Total	2,108	2,218	4,826	846	1,373	11,370
Number of ships						
Total ships	13,430	13,544	35,005	6,514	51,652	120,146
New ships (built after 2012)	6,319	3,747	17,741	2,084	16,529	46,420
% new	47%	28%	51%	32%	32%	39%

In Table 172, Table 148 and Table 174 the number of ships for 53 sub-categories of ship types in 2020 are presented, as calculated with the energy demand projection model from the Third IMO GHG Study 2014.

Table 172 Number of ships and share of new ships in 2020 for base case scenario

Ship type	Ship size	Cargo type	Total ships	Of which built in/after 2012	% of fleet built in/after 2012
Bulk carrier	0-9999	Bulker	1,628	823	51%
Bulk carrier	10000-34999	Bulker	3,005	1383	46%
Bulk carrier	35000-59999	Bulker	4,078	1997	49%
Bulk carrier	60000-99999	Bulker	3,013	1475	49%
Bulk carrier	100000-199999	Bulker	1,812	972	54%
Bulk carrier	200000-+	Bulker	395	194	49%
Chemical tanker	0-4999	Tanker	1,475	430	29%
Chemical tanker	5000-9999	Tanker	908	265	29%
Chemical tanker	10000-19999	Tanker	1,023	299	29%
Chemical tanker	20000-+	Tanker	1,448	423	29%
Container	0-999	Unitized	1,492	706	47%
Container	1000-1999	Unitized	1,673	755	45%
Container	2000-2999	Unitized	996	497	50%
Container	3000-4999	Unitized	1,135	447	39%
Container	5000-7999	Unitized	764	360	47%
Container	8000-11999	Unitized	501	261	52%
Container	12000-14500	Unitized	216	147	68%
Container	14500-+	Unitized	65	57	88%
General cargo	0-4999	General Cargo	15,928	8053	51%
General cargo	5000-9999	General Cargo	4,055	2050	51%
General cargo	10000-+	General Cargo	2,837	1434	51%
Liquefied gas tanker	0-49999	Tanker	897	132	15%
Liquefied gas tanker	50000-199999	Tanker	505	169	33%
Liquefied gas tanker	200000-+	Tanker	41	7	18%
Oil tanker	0-4999	Tanker	3,366	982	29%
Oil tanker	5000-9999	Tanker	651	190	29%
Oil tanker	10000-19999	Tanker	187	54	29%
Oil tanker	20000-59999	Tanker	663	194	29%
Oil tanker	60000-79999	Tanker	386	113	29%
Oil tanker	80000-119999	Tanker	902	263	29%
Oil tanker	120000-199999	Tanker	467	136	29%
Oil tanker	200000-+	Tanker	597	174	29%
Other liquids tankers	0-+	Tanker	144	42	29%
Ferry-pax only	0-1999	Passenger	3,068	982	32%
Ferry-pax only	2000-+	Passenger	71	23	32%
Cruise	0-1999	Passenger	198	63	32%
Cruise	2000-9999	Passenger	69	22	32%
Cruise	10000-59999	Passenger	114	36	32%
Cruise	60000-99999	Passenger	87	28	32%
Cruise	100000-+	Passenger	51	16	32%
Ferry-RoPax	0-1999	Passenger	1,662	532	32%
Ferry-RoPax	2000-+	Passenger	1,194	382	32%
Refrigerated bulk	0-1999	General Cargo	1,796	1083	60%
RoRo	0-4999	Unitized	2,150	1296	60%
RoRo	5000-+	Unitized	670	404	60%
Vehicle	0-+	Unitized	451	272	60%
Vehicle	4000-+	Unitized	901	544	60%
Yacht	0-+	Miscellaneous	1,561	500	32%
Service - tug	0-+	Miscellaneous	14,610	4675	32%
Miscellaneous - fishing	0-+	Miscellaneous	22,229	7113	32%
Offshore	0-+	Miscellaneous	6,871	2199	32%
Service - other	0-+	Miscellaneous	580	186	32%
Miscellaneous - other	0-+	Miscellaneous	5,801	1856	32%
Total			121,385	47,700	39%

Table 173 Number of ships and share of new ships in 2020 for high case scenario

Ship type	Ship size	Cargo type	Total ships	Of which built in/after 2012	% of fleet built in/after 2012
Bulk carrier	0-9999	Bulker	1,612	805	50%
Bulk carrier	10000-34999	Bulker	2,976	1351	45%
Bulk carrier	35000-59999	Bulker	4,038	1953	48%
Bulk carrier	60000-99999	Bulker	2,984	1443	48%
Bulk carrier	100000-199999	Bulker	1,795	952	53%
Bulk carrier	200000-+	Bulker	391	190	49%
Chemical tanker	0-4999	Tanker	1,596	556	35%
Chemical tanker	5000-9999	Tanker	983	343	35%
Chemical tanker	10000-19999	Tanker	1,107	386	35%
Chemical tanker	20000-+	Tanker	1,568	546	35%
Container	0-999	Unitized	1,514	728	48%
Container	1000-1999	Unitized	1,697	781	46%
Container	2000-2999	Unitized	1,011	512	51%
Container	3000-4999	Unitized	1,152	464	40%
Container	5000-7999	Unitized	775	371	48%
Container	8000-11999	Unitized	509	268	53%
Container	12000-14500	Unitized	219	151	69%
Container	14500-+	Unitized	66	58	88%
General cargo	0-4999	General Cargo	16,160	8293	51%
General cargo	5000-9999	General Cargo	4,114	2111	51%
General cargo	10000-+	General Cargo	2,878	1477	51%
Liquefied gas tanker	0-49999	Tanker	1,079	316	29%
Liquefied gas tanker	50000-199999	Tanker	607	273	45%
Liquefied gas tanker	200000-+	Tanker	49	16	32%
Oil tanker	0-4999	Tanker	3,644	1270	35%
Oil tanker	5000-9999	Tanker	705	246	35%
Oil tanker	10000-19999	Tanker	202	70	35%
Oil tanker	20000-59999	Tanker	718	250	35%
Oil tanker	60000-79999	Tanker	418	146	35%
Oil tanker	80000-119999	Tanker	977	340	35%
Oil tanker	120000-199999	Tanker	506	176	35%
Oil tanker	200000-+	Tanker	646	225	35%
Other liquids tankers	0-+	Tanker	156	54	35%
Ferry-pax only	0-1999	Passenger	3,068	982	32%
Ferry-pax only	2000-+	Passenger	71	23	32%
Cruise	0-1999	Passenger	198	63	32%
Cruise	2000-9999	Passenger	69	22	32%
Cruise	10000-59999	Passenger	114	36	32%
Cruise	60000-99999	Passenger	87	28	32%
Cruise	100000-+	Passenger	51	16	32%
Ferry-RoPax	0-1999	Passenger	1,662	532	32%
Ferry-RoPax	2000-+	Passenger	1,194	382	32%
Refrigerated bulk	0-1999	General Cargo	1,822	1110	61%
RoRo	0-4999	Unitized	2,181	1329	61%
RoRo	5000-+	Unitized	679	414	61%
Vehicle	0-+	Unitized	457	279	61%
Vehicle	4000-+	Unitized	914	557	61%
Yacht	0-+	Miscellaneous	1,561	500	32%
Service - tug	0-+	Miscellaneous	14,610	4675	32%
Miscellaneous - fishing	0-+	Miscellaneous	22,229	7113	32%
Offshore	0-+	Miscellaneous	6,871	2199	32%
Service - other	0-+	Miscellaneous	580	186	32%
Miscellaneous - other	0-+	Miscellaneous	5,801	1856	32%
Total			123,069	49,428	40%

Table 174 - Number of ships and share of new ships in 2020 for low case scenario

Ship type	Ship size	Cargo type	Total ships	Of which built in/after 2012	% of fleet built in/after 2012
Bulk carrier	0-9999	Bulker	1,569	761	49%
Bulk carrier	10000-34999	Bulker	2,897	1269	44%
Bulk carrier	35000-59999	Bulker	3,931	1842	47%
Bulk carrier	60000-99999	Bulker	2,905	1361	47%
Bulk carrier	100000-199999	Bulker	1,747	903	52%
Bulk carrier	200000-+	Bulker	380	179	47%
Chemical tanker	0-4999	Tanker	1,462	417	29%
Chemical tanker	5000-9999	Tanker	900	257	29%
Chemical tanker	10000-19999	Tanker	1,014	289	29%
Chemical tanker	20000-+	Tanker	1,436	410	29%
Container	0-999	Unitized	1,466	679	46%
Container	1000-1999	Unitized	1,644	726	44%
Container	2000-2999	Unitized	979	479	49%
Container	3000-4999	Unitized	1,115	426	38%
Container	5000-7999	Unitized	750	346	46%
Container	8000-11999	Unitized	492	252	51%
Container	12000-14500	Unitized	212	144	68%
Container	14500-+	Unitized	64	56	87%
General cargo	0-4999	General Cargo	15,649	7769	50%
General cargo	5000-9999	General Cargo	3,984	1978	50%
General cargo	10000-+	General Cargo	2,787	1384	50%
Liquefied gas tanker	0-49999	Tanker	889	123	14%
Liquefied gas tanker	50000-199999	Tanker	501	164	33%
Liquefied gas tanker	200000-+	Tanker	40	7	17%
Oil tanker	0-4999	Tanker	3,337	952	29%
Oil tanker	5000-9999	Tanker	646	184	29%
Oil tanker	10000-19999	Tanker	185	53	29%
Oil tanker	20000-59999	Tanker	657	188	29%
Oil tanker	60000-79999	Tanker	383	109	29%
Oil tanker	80000-119999	Tanker	895	255	29%
Oil tanker	120000-199999	Tanker	463	132	29%
Oil tanker	200000-+	Tanker	592	169	29%
Other liquids tankers	0-+	Tanker	142	41	29%
Ferry-pax only	0-1999	Passenger	3,068	982	32%
Ferry-pax only	2000-+	Passenger	71	23	32%
Cruise	0-1999	Passenger	198	63	32%
Cruise	2000-9999	Passenger	69	22	32%
Cruise	10000-59999	Passenger	114	36	32%
Cruise	60000-99999	Passenger	87	28	32%
Cruise	100000-+	Passenger	51	16	32%
Ferry-RoPax	0-1999	Passenger	1,662	532	32%
Ferry-RoPax	2000-+	Passenger	1,194	382	32%
Refrigerated bulk	0-1999	General Cargo	1,765	1051	60%
RoRo	0-4999	Unitized	2,112	1258	60%
RoRo	5000-+	Unitized	658	392	60%
Vehicle	0-+	Unitized	443	264	60%
Vehicle	4000-+	Unitized	886	527	60%
Yacht	0-+	Miscellaneous	1,561	500	32%
Service - tug	0-+	Miscellaneous	14,610	4675	32%
Miscellaneous - fishing	0-+	Miscellaneous	22,229	7113	32%
Offshore	0-+	Miscellaneous	6,871	2199	32%
Service - other	0-+	Miscellaneous	580	186	32%
Miscellaneous - other	0-+	Miscellaneous	5,801	1856	32%
Total			120,146	46,409	39%

Annex E LNG demand projections

E.1 Introduction

This annex describes the method used and results of the projections of LNG demand as a fuel market, which is intended as opposed to boil-off LNG consumed in the machinery of LNG carriers. The LNG demand projections by 2020 are based on a quantitative estimate using the shipping model GloTraM. Extensive details of the model can be found in Haji et al., (2016a) and Smith et al. (2012a). The model is focused on the key economic technical and operational considerations for estimating the evolution of energy demand for shipping. We applied the following steps for estimating the energy demands of the three ship types (tankers, bulk carriers and container ships) that dominate total shipping energy demand, as defined in the Third IMO Greenhouse Gas Study (IMO, 2014).

- We aligned GloTraM with the assumptions used in this study (e.g. scrubbers' costs, fuel prices projections and transport work).
- We sourced estimates to the input assumptions required by the model that were not possible to align (because of differences in model structure), using existing literature and where necessary expert judgment.
- We run the model GloTraM, which then calculates the fuel consumption for the fleets of each ship type, for time-steps between baseline year (2012) and 2020.
- We performed a sensitivity analysis around different LNG price projections
- We compared the LNG demand projections obtained using GloTraM with the projections of the LNG demand in 2020 found in the existing literature.
- We compared the results obtained using GloTraM with the results obtained from
  CE Delft's model in order to consider whether it is appropriate the use GloTraM as the source for the LNG demand estimates.

E.2 Method to evaluate LNG demand in 2020

GloTraM (Global Transport Model) has been developed to explore shipping's future scenarios ((Lloyds & UCL, 2014), Low Carbon Shipping & Shipping in Changing Climates research programme (Low Carbon Shipping, ongoing). GloTraM simulates the evolution of the shipping fleet from a baseline year to the projection year. The model is initiated in a baseline year using data obtained from the Third IMO GHG Study 2014 and a number of external sources of data (further details can be found in Haji et al. (2016b) and Smith (2012b) that characterises the shipping industry at that point in time, then the model time-steps forwards simulating the decisions made by shipping owners and operators in the management and operation of their fleets. The model deploys a 'profit maximising' approach, assuming that individual owners/operators make decisions to maximise their profit, and the model includes the representation of known market barriers and failures (e.g. the charterer owner split incentive) in order to generate scenarios of technology and operational change that match actual observed behaviour as closely as possible. The model evolves the fleet and its activity in response to the developments in relevant factors between the base year and the projection year (e.g. changing fuel prices, transport demand, regulation and technology availability).
The interaction with fuels and other technologies are considered and result in estimates of the specifics of how these parameters could evolve.

The viability of an investment such as the use of scrubber technology or the use of an alternative fuel such as LNG, is normally considered by comparing the expected return over the lifetime of the investment. The investment choice is therefore modelled as the shipowner seeks to maximise profits under an evolving landscape of economic drivers and regulatory drivers.

The main drivers that the model takes into account are:
- transport demand;
- fuel price projections;
- ship capital expenditure;
- operating costs and revenues;
- average operating speed;
- technology costs and performance;
- fleet stock (types, age and technical specification of the existing fleet);
- regulations (including MARPOL Annex VI: EEDI, SO_x and NO_x regulations).

The transport demand projection is an exogenous input parameter of the model and has been aligned to the transport demand projection used in CE Delft's model that is based on socio-economic developments (Section 4.1). The evolving transport demand also affects the fleet composition and turnover (the number of ships that are laid up, and the number of new builds in any one year).

The profitability of any combination of fuel and machinery changes over time because of the evolution over time of the individual fuel prices and regulations. Input assumptions of the fuel price projections are provided in Section E.3 .

Capital costs of different engine types and sizes are taken into account in the model as well as the specific fuel consumptions and the costs of alternative fuel storage system on board ships. Table 175 presents the input assumptions used in the model.

Table 175 Ship capital expenditures and specific fuel consumptions

Description	Investment costs	Specific fuel consumption
	Million USD per MW	(@75% MCR) g/kWh
2 stroke diesel	0.4	170
4 stroke diesel	0.4	180
Diesel electric	0.5	190
LNG dual-fuelled engines/gas engine + LNG storage system	1.40	150

The model estimates the components of operating annual costs, including the voyage costs. These depend mainly on fuel consumption, fuel price and operational conditions such as days active, days at port per nautical mile, ratio of ballast days to loaded days, time spent in ECAs, and days at sea per year. Operational conditions at base year are aligned with the results of the Third IMO GHG Study 2014. The model also takes into account the annual revenue expressed as price paid for unit of transport supply and the quantity of transport supply per year.

Changes in average speed affect the fleet productivity. The model takes into account different speeds in order to capture the interaction between the optimal operation speed and the technical energy efficiency.

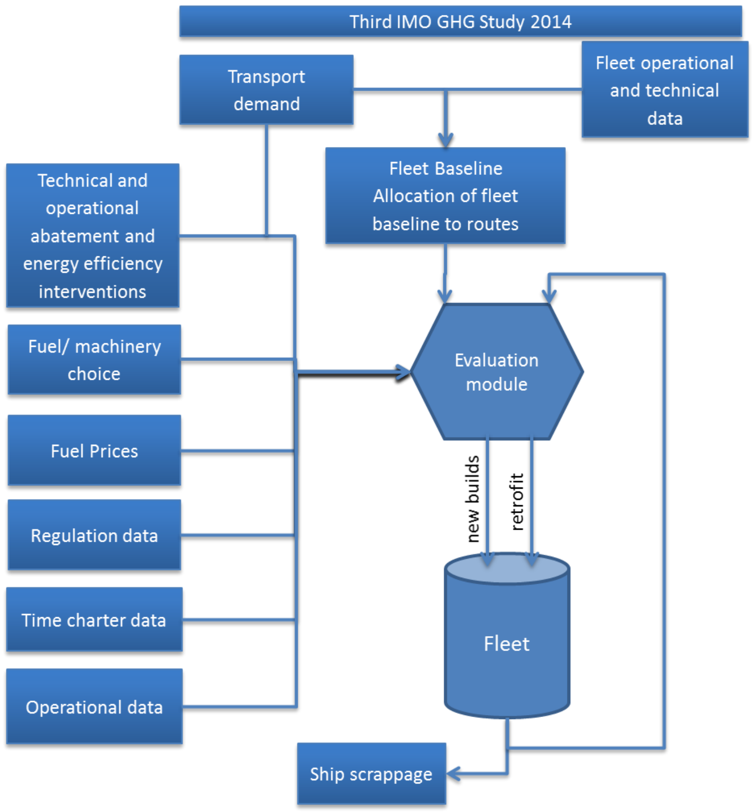
All major technical and operational abatement and energy efficiency interventions are included. At each time step costs and performance of each technology and combination of technologies are evaluated based on the profit maximisation function.

In this analysis only three shiptypes have been considered: container, dry and wet crude. At each time step the fleet evolves taking into account ship scrappage, retrofit of the existing fleets, and the specification of the newbuild fleets.

The model takes into account that ships will meet the EEDI requirements, the SO_x and NO_x limit in place until 2020, and all relevant MARPOL Annex VI regulations.

Figure 23 present a schematic overview of the GloTraM model.

Figure 23 Schematic overview of the GloTraM model



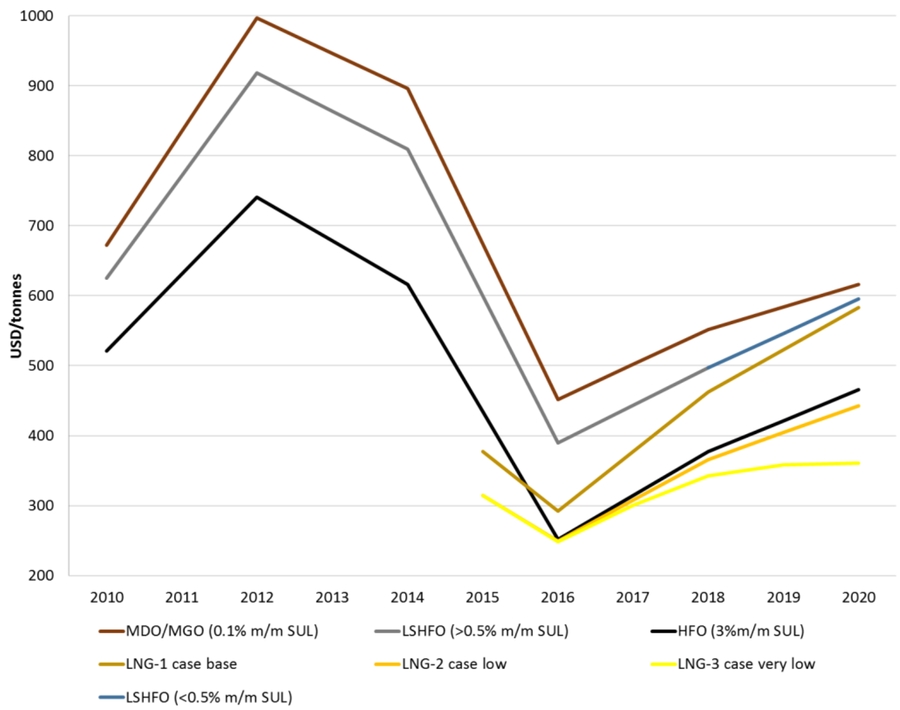
E.3 Fuel price assumptions and sensitivity cases of LNG price projections

An important component of the business case for the selection of LNG as a marine fuel is the LNG fuel price. We assume that LNG up to 2020 will be sold at a discounted price to HFO price per unit of energy. So, we first calculate the LNG price that would be equal to that of HFO on an energy basis using a conversion factor of 1.36 (assuming the energy densities of HFO and LNG of

40 MJ/kg and 55 MJ/kg, respectively). Eventually, we discounted this price of 50 USD, based on the discussions with stakeholder. Although the detailed parameters can vary in long term contracts, this mechanism is commonly used in LNG pricing as around 70% of the LNG traded around the world is linked to oil prices (IPA, 2015).

In the main report, we used the LNG price projection defined as “case base” in all cases defined as base, high, and low in Section 4.1, Table 10. In this Annex, we then perform a sensitivity analysis with two other LNG price projections, defined as case low and case very low in order to test the robustness of the stated fuel price and its influence on the demand for LNG. Figure 24 shows both the fuel price projections (all fuels considered) and all the sensitivity cases of LNG price projections.

Figure 24 Fuel price projections and sensitivity LNG price projections



Product	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
HFO (3% m/m)	521	631	741	679	616	434	252	315	377	422	466
MGO (0.10% m/m)	672	835	997	947	896	674	452	502	552	584	616
LSHFO (>0.50% m/m)	625	772	918	864	809	600	390	444	497		
LSHFO (<0.50% m/m)										546	595
LNG-1 case base						377	292	377	462	523	583
LNG-2 case low						315	249	308	366	405	443
LNG-3 case very low						315	248	300	343	358	361

LNG pricing mechanisms are different in different world regions, for example in North American prices are more or less disconnected from the oil reference, in Europe the gas sold with reference to the price at European gas trading hubs is growing, and in Asia Pacific region LNG price is fixed within the long term crude oil indexed contracts (TNO, 2014). IEA (OECD/IEA, 2013) projects that in

2020 LNG price will vary from 250 USD per tonnes in United States to 690 USD per tonnes in Japan, approximately. If there will be a situation in which regional prices will respond to a single global gas price signal, it is likely that LNG price will follow the same trend of natural gas price. This means that LNG price could potentially be lower than our initial estimate. Therefore, we assume that the LNG price in the case low is just below HFO price, while LNG price for the case very low gradually becomes cheaper than any other fuels. We assume that these two cases are representative of a different LNG pricing mechanism which follows a global gas price signal. Other studies have also assumed LNG price to be lower than HFO price in terms of USD per tonnes (DNV GL; PWC, 2016)[3] DNV (DNV, 2012), (Lloyds Register, 2012). This is in line with our assumptions on LNG price projections for the sensitivity cases, which therefore can be considered appropriated.

The influence of these different fuel price cases on the demand for LNG in 2020 is presented in Section E.4 and E.6.

E.3.1 Availability of LNG in ports

The use of LNG has been restricted by the fact that LNG is only available as a bunker fuel in a limited number of ports (CE Delft; TNO, 2015). However, the number of facilities is growing rapidly and all world regions currently offer LNG as a bunker fuel, with the number of ports set to double in the coming years, as shown in Table 176.

Table 176 The number of LNG bunkering facilities different regions

	Bunker ship loading facility	Bunker vessel	Tank to ship bunkering	Truck loading facilities	Unspecified
	In operation (investment decision taken)				
Norway	1 (-)	-	11 (1)	10 (2)	-
Rest of Europe	6 (6)	1 (5)	3 (10)	12 (17)	3 (6)
Middle East (incl. Turkey)	-	-	-	-	(1)
Asia	- (1)	-	8 (5)	2 (2)	-
America	- (2)	- (1)	1 (1)	3 (2)	- (1)
Australia	-	-	-	- (2)	-

Source: LNGi - DNV GL's intelligence portal for LNG as ship fuel.

E.4 Projection of LNG demand as an alternative fuel

This section presents the results of the fleet evolution modelling of newbuilds LNG-fuelled ships using the model GloTraM. As mentioned in the main report we focus on LNG for newbuilds.

The GloTraM fleet is considered to be a representative subset of the energy demand of the total fleet, although not all ship types have been simulated within the model. One way to obtain the LNG use by 2020 of the global fleet is by extrapolating the 2020 LNG use of the fleet analysed within GloTraM. Table 177 presents the GloTraM estimated LNG demand in 2020 for the three ship types modelled in GloTraM for the base, high and low cases. It also shows

3 Note: estimates are only for the European Countries.

the LNG demand of the global fleet considering that the GloTraM fleet account for about 60% of the total demand of the global fleet.

Table 177 Estimated LNG demand in 2020 in shipping for the base, high and low cases (mln tonnes)

	2020 base	2020 high	2020 low
LNG as a fuel market (GloTraM fleet)	2.0	2.3	1.9
LNG as a fuel market (global fleet) (1)	3.2	3.7	3.0

(1) Global fleet excludes LNG carriers.

Table 178 presents the estimated LNG demand for the sensitivity cases low and very low as described in Section E.3. As LNG becomes cheaper relative to the oil-derivative fuels, its demand is expected to increase. The table also shows the proposed LNG demand of the global fleet using the extrapolation method described above.

Table 178 Estimated LNG demand in 2020 in shipping for the sensitivity cases low and very low (mln tonnes)

	2020 LNG 1 case base	2020 LNG 2 case low	2020 LNG 3 case very low
LNG as a fuel market (GloTraM fleet)	2.0	9.1	12.0
LNG as a fuel market (global fleet(1))	3.2	14.6	19.2

(1) Global fleet is excluding LNG carriers.

Based on our analysis we estimate that in the period up to 2020, LNG demand as a fuel market may increase to 3.2 million tonnes in the base case.
The variation of transport work among the cases base, high and low transport work described in Table 10, socio-economic scenarios, only results in a small range between the high and low cases (from 3 to 3.7 million tonnes). However, the variations of the LNG price projections show that LNG demand may increase up to 14.6 million tonnes in the LNG low case and 19.2 million tonnes in the very low case, which highlights the importance of input assumptions about fuel prices to the total estimated demand.

E.5 Comparison with LNG demand as a fuel market in 2020 in shipping given by existing literature

A number of studies have offered an estimate of the LNG demand as a fuel market in 2020 in shipping. These estimates vary based on assumptions made with regard to a number of factors and scope of the analysis.

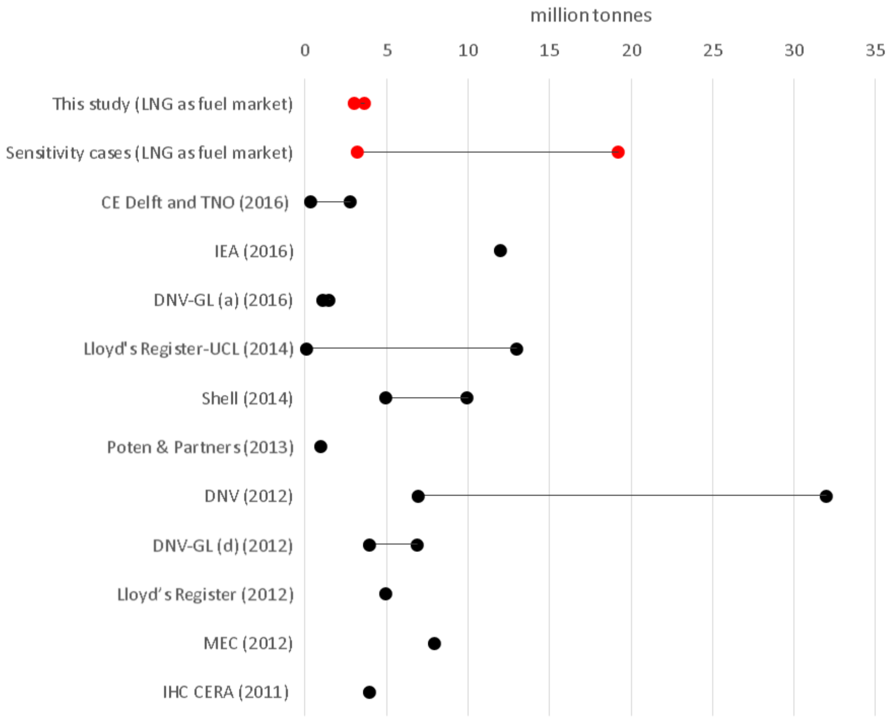
DNV (c) (2012) developed four scenarios with a different combination of economic growth and LNG prices. We observe a big range between the scenario with low uptake of LNG and the scenario with high uptake of LNG (7 to 32 million tonnes). Lloyd's Register-UCL (2014) developed three scenarios using another version of the model GloTraM aligned to input assumptions from the global marine trend scenarios provided by Lloyd’s Register. LNG demand in 2020 was estimated to range between 0.12 and 13 million tonnes. Previously, Lloyd’s Register (2012) developed another three scenarios with high, low and medium LNG price and focusing on LNG-fuelled new builds demands. While the high LNG price case estimates very low LNG demand, for the medium and low

LNG price cases the LNG demand was estimated to be from 1 to up 5 million tonnes in 2020. CE Delft and TNO (2015) developed three scenarios for the use of LNG on European coastal shipping. Their results also show a wide variation of LNG consumption, ranging from 0.25 to 6.3 million tonnes in 2030 for ships sailing in European waters, depending on the fuel price and availability of LNG.

We found other recent references in the literature that have provided their own estimate of LNG demand in 2020. In particular, IHC CERA (2011) estimated the demand from LNG carriers and the demand from commercial ships, while MEC (2012) estimated the number of LNG ships operating and number of LNG new builds. IEA (2016) claimed that LNG bunkering market could soar over the next few years replacing a significant share of oil-based fuels and correspond to about 12-13 million tonnes in 2020.

In general, we notice that often results of these analyses present a wide range, varying from just below 1 million tonnes to more than 10 million tonnes of LNG demand as a fuel market in 2020. Figure 25 summaries LNG demand projections in 2020 found in the existing literature and it also includes the estimates provided in this study. The projections obtained with GloTraM in this study are within the range of the values of LNG size market in 2020 given by in the existing literature. The results from the sensitivity cases offered in this study are also plotted. These are also consistent with the ranges provided by other studies and imply that the likely explanation for the wide ranges observed in other studies is also related to the assumption about the spread between the LNG price and oil-based fuel prices.

Figure 25 Comparison between the LNG demand projections in 2020 given by the existing literature and the estimates of this study



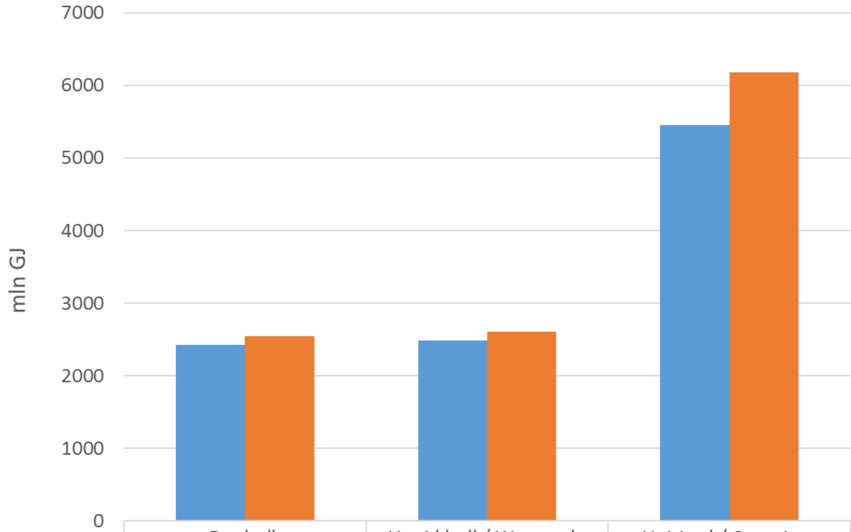
CE Delft and TNO (2015): EC LNG Study, LOT3, Analysis of the LNG market development in the EU, CE Delft (2015). Note: estimates are only for the year 2030 only for the European countries.

IEA (2016): OECD/IEA Oil Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021.
It assumes that 0.3 mb/d of oil based fuels can be replaced by LNG by 2021. This is equivalent to 12 million tonnes of LNG.
DNV-GL (2016a) DNV-GL & PWC: EC LNG Study, LOT1 (Analysis and evaluation of identified gaps and of the remaining aspects for completing an EU-wide framework for marine LNG distribution, bunkering and use). Note: estimates are only for the European countries.
Lloyd's Register-UCL (2014): Lloyd's Register-UCL, Global Marine Fuel trend 2030. Note: only three types of ships.
Shell (2014): LNG AS MARINE FUEL. 16th January, Viking Grace
Poten & Partners (2013): Adamchak, Frederick, and A. Adede. "LNG as marine fuel." LNG-17 Conference. 2013.
DNV-GL (c) (2012): DNV, Shipping 2020, 2012.
DNV-GL (d) (2012): DNV, LNG bunkering demand and bunkering infrastructure, 2012.
Lloyd's Register (2012): Lloyd's Register, LNG-fuelled deep-sea shipping, 2012.
MEC (2012): MEC, Future Demand for all Types of Marine Fuels over the Next Two Decades. The European Fuels Conference. March 2012, Paris.
IHC CERA (2011): IHC CERA, The next bunker fuel.

E.6 Comparison between GloTraM and CE Delft's models results

The estimation of demand for conventional marine fuels has to be coherent with the estimation of LNG demand. We check the validity of the use of GloTraM's output for LNG in the fuel demand projection in Table 1 by comparing the energy demand obtained with GloTraM with the energy demand obtained with CE Delft's model. Figure 26 compares the total energy demand by ship types in 2020 between the two models. The results from the two models are similar therefore demonstrating coherency. Small differences can be associated with the different type of aggregation used (e.g. exactly which ship types might be aggregated within these three categories).

Figure 26 Comparison of total energy demand by ship types in 2020 between GloTraM and CE Delft's model



	Dry bulk	Liquid bulk/ Wet crude	Unitized / Container
CE Delft's model	2422	2482	5448
GloTraM	2545	2610	6181

Based on this comparison we assess the models to be aligned enough to consider appropriate the use of GloTraM as the source for the LNG demand estimates.

Annex F List of stakeholders contacted

In the course of this project, we conducted in-depth interviews with representatives from:

- Alfa Laval;
- Carnival;
- DuPont BELL;
- Ecospray;
- Hapag Lloyd;
- Ionada;
- Maersk;
- Royal Belgian Shipowners Association;
- SEA Europe;
- Spliethoff;
- Wärtsilä;
- Royal Dutch Shell;
- CONCAWE.