LNG and methane-based marine fuels

Prospects for the shipping industry

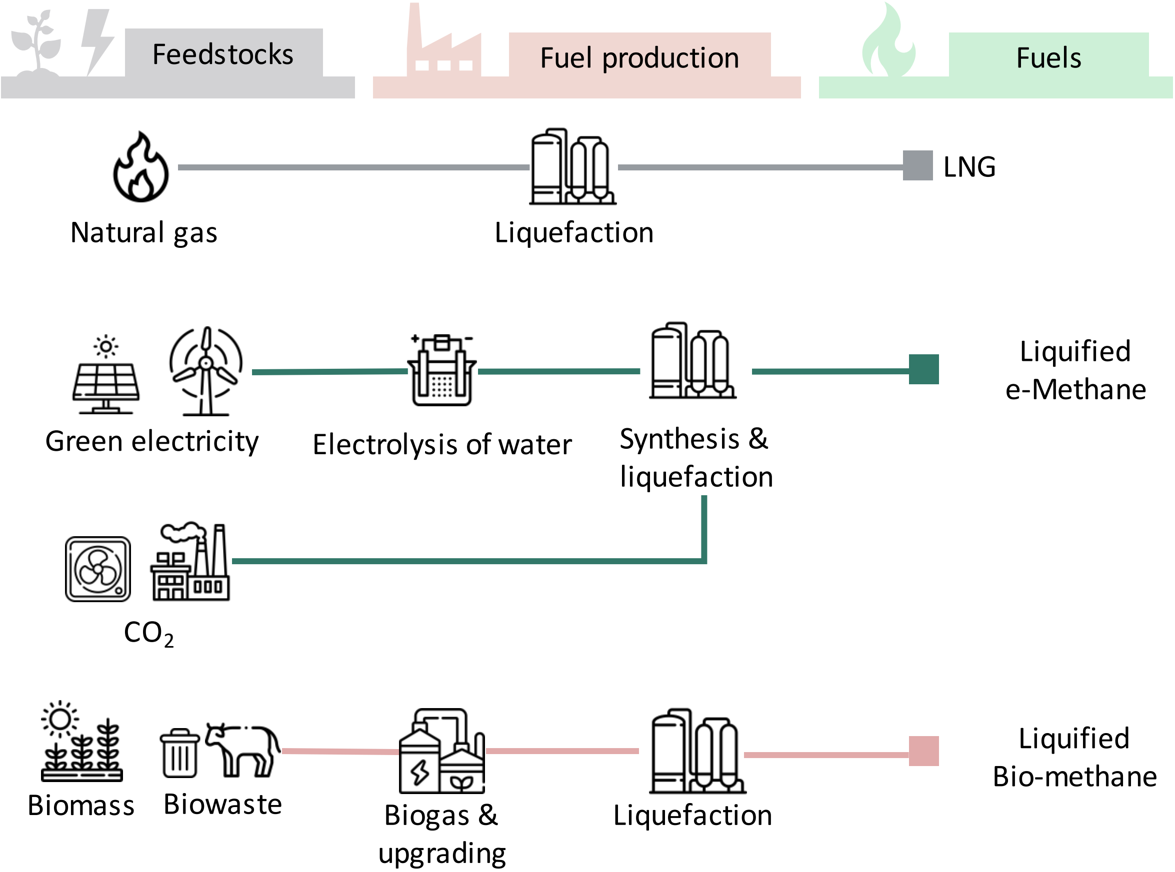
Documentation of assumptions for NavigaTE 1.0 (2021)

February 2022

Mærsk Mc-Kinney Møller Center
for Zero Carbon Shipping

Agenda

Renewable methane from biomass or electricity is a candidate for replacing fossil-based LNG and fuel oils in shipping



- Renewable liquefied methane can be produced from various pathways:
  1. E-methane synthesized from green hydrogen and CO_2 captured either from point-source or direct air capture
  2. Bio-methane produced from anaerobic digestion on biowaste or biomass. (Boosting with green hydrogen not studied here)
  3. Bio-methane produced from gasification of biowaste or biomass and methanation of synthesis gas. (not studied here.)
  4. Purification / boosting of landfill biogas (not studied here)
- The produced methane will likely need to be transported to a liquefaction plant to be liquified. The availability of a methane certificate trading system changes the details of how this will be done
- For bio-methane, the liquefaction plant would likely be centralized due to the economies of scale of liquefaction. Pooling of bio-methane in natural gas pipelines and certificate trading will be an advantage
- E-methane plants must be built at larger scale than bio-methane plants, so liquefaction of methane may be performed locally. However, CO_2 infrastructure is required to pool ample feedstock.

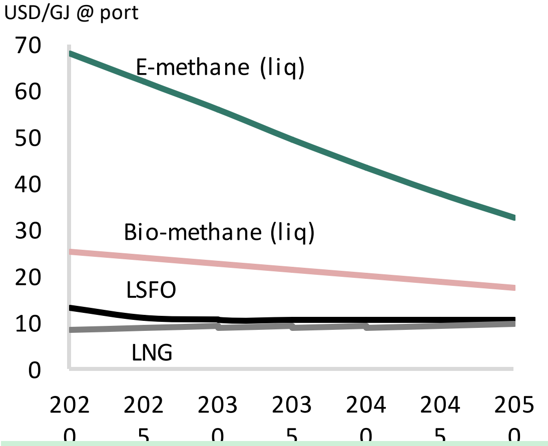
Note: Only key processes are included; Icons from: Bqlnq, freepik, Vitally Gorbachev

Pathways from LNG to renewable methane or ammonia could be viable for part of the fleet if methane emissions can be addressed in production chain & onboard

Key conclusions

- Liquified renewable methane is an easily adoptable low-carbon fuel, with established logistics channels and industry experience in being used as a fuel
- Methane fugitive emissions throughout the value chain can negate the GHG emission reduction achieved upstream. It is critical to eliminate those
- Regulatory measures are needed to make liquified bio- and e-methane cost competitive with fossil fuels. Liquified bio-methane is the lowest cost renewable methane option past 2050
- Bio-methane could be supplied to cover >10% of global fleet from 2040 – the actual uptake depends on price competition with other sectors (see bio-methane chapter)
- Vessel pathways exist to prepare or retrofit an LNG-fueled vessel mainly for ammonia use

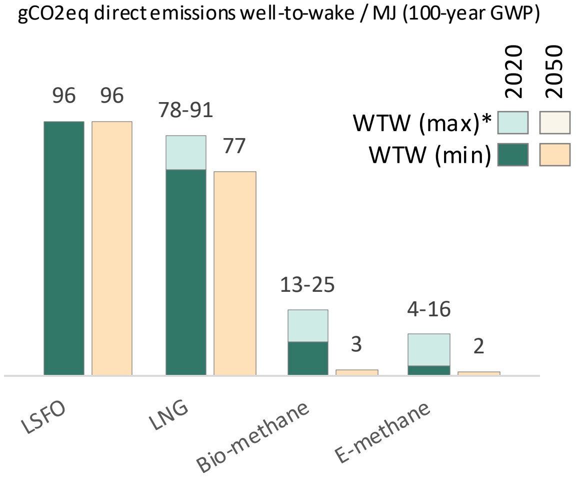
Cost projections



Renewable methane fuels will require regulatory measures to compete

- Bio-methane is projected to be the cheapest source of renewable methane at 2-2.5 times the price of LNG until 2050
- E-methane expected to be more than 3 times as expensive as fossil alternatives at least until 2050

Direct emissions



Methane fuels can reduce emissions

- TTW emissions can vary widely based on engine technology and their methane slip
- Bio- and e-methane release biogenic CO_2 that do not add to global warming
- Bio-methane can be a GHG sink due to improved waste management practices
- E-methane expected to be almost emission free to produce (no upstream methane)
- Onboard methane slip reduction techn. available or developed within ≈2025

Implementation risk

Establishing pathways is low risk, but regulatory measures are needed to drive down slips and unlock the market

- **[Feedstock]** E- and bio-methane's need for sustainable CO_2 / Biomass could drive availability or price at long term
- **[Feedstock]** Green methane certificate trading scheme is necessary broadly to be able to use current pipeline infrastructure to achieve low logistic costs
- **[Regulatory, onboard]** Methane slip to be addressed by regulation and further adoption of near-term technologies and solutions

*WTW values range depending on onboard engine technology and operation, in particular the associated methane slip; pilot fuel excluded from WTW emission value
1: Pilot fuel (1-2%) is needed. Using LSFO, this equals up to an additional 2 gCO_2eq/MJ.

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Bio-methane will need regulatory measures to be cost competitive with fossil alternatives

Highlights from cost analysis of bio-methane

- In all years, the <u>cost</u> of producing liquefied bio-methane is 2-2.5 times higher than the <u>price</u> of LNG at 9 USD/gj
- Thus, liquefied bio-methane will need regulatory measures to be cost competitive with fossil alternatives
- The cost of producing liquefied bio-methane is sensitive to 3 main drivers:

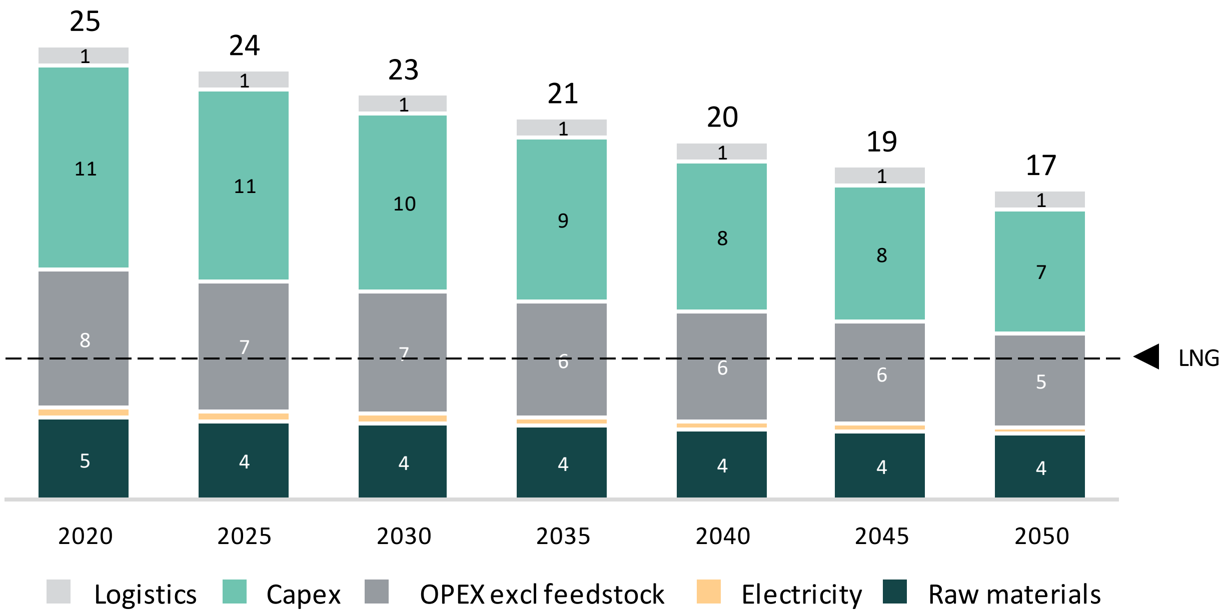
1. Capital and operational expenses of the biogas- and upgrade plants, which is believed to be reducible by 20% towards 2050 following an industry learning curve
2. The conversion efficiency of the biogas process, which is believed to increase 220 to 270 kg methane per ton dry waste towards 2050 from technological improvements
3. The price of feedstock (oMSW, sludge, low-cost agricultural waste…), which is projected at 50 USD/ton, and remain relatively stable throughout 2050

- The utilization of the CO_2 stream from upgrading biogas, e.g. by selling CO_2 or upgrading it using hydrogen, is not evaluated in the first version of the molecule paper
- The added value from sales of degassed digestate is not included in this first version of the molecule paper

Liquified bio-methane pathway costs, at port

Weighted global average[1]

USD/GJ



1) Assuming 40 % from lowest cost region, 30 % from 2nd lowest, and 10% from 3-5th.

Bio-methane supply is restricted by biomass available near to existing gas grids and competition with other industries which drives the price

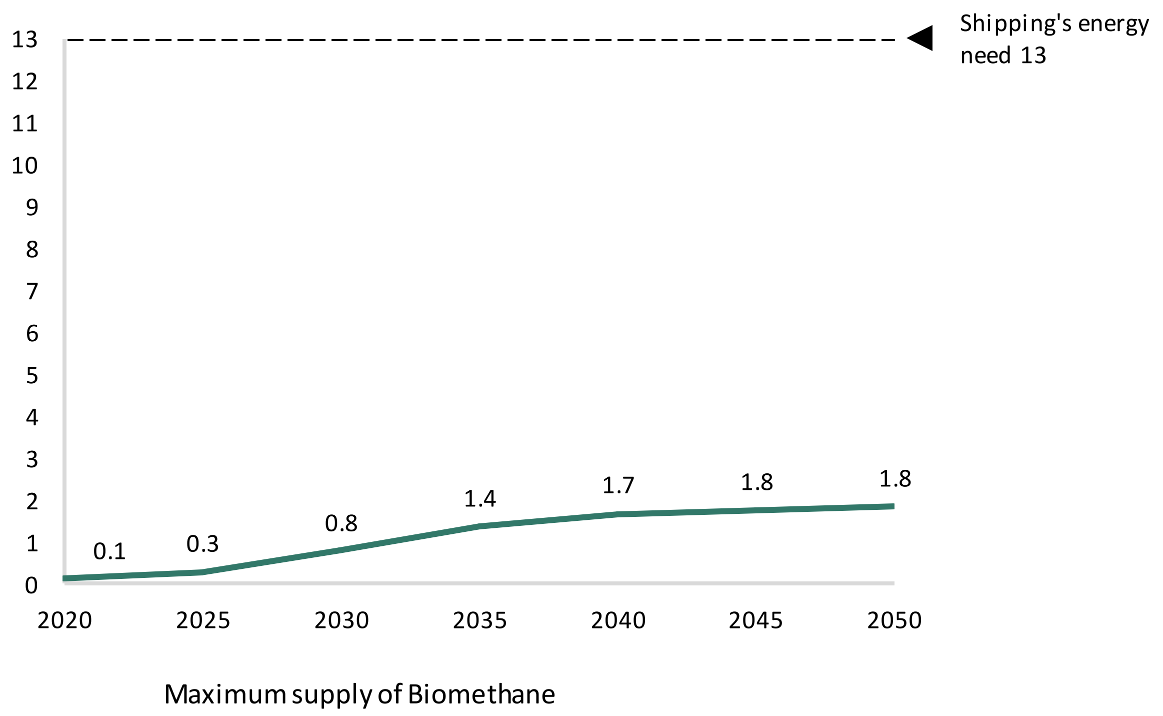
Highlights from supply analysis of bio-methane

- 1.3 EJ of Biogas[1] is produced globally for all industries today (data not shown)
- The maximum potential for bio-methane for all industries is limited to 23 EJ from the amount of biomass suitable for biogas production near existing gas lines[2].
- To simulate competition with other industries, we set a maximum volume of bio-methane obtainable for the maritime industry: Maritime's current fraction of the energy demand across all industries which is deemed non-electrifiable is 8%.[3] For the analysis, we used 8% of bio-methane potential as the maximum boundary for shipping, due to the drivers that could push shipping to conquer a higher fraction of bio-methane than its relative need being counteracted by the higher cost of use for shipping from liquefaction and methane slip.[4] This sets the maximum bio-methane obtainable by shipping to 1.8 EJ
- The timing of the availability is limited by the maximum roll-out speed of biogas plants, even if supply is unconstrained. Considering the maximum roll-out speed, modelled by assessing historical biofuel roll-out speeds of technical and commercial mature technologies with government support,[5] bio-methane could grow to reach the maximum availability by 2040.
- This leads us to conclude that bio-methane could be supplied to cover >10% of the fleet from 2035 – the actual uptake depends on price competition with other sectors

Fastest possible roll-out of bio-methane supply available for maritime, with unconstrained demand

EJ/year

(Standard plants supplying shipping[6])



1) IEA outlook for biogas and biomethane 2020. **2)** An internal study set the maximum sustainable global biomass production to 130 EJ excluding dedicated crops (otherwise, 200EJ), of which 75 EJ is suitable for bio-methane production (wet waste, oils, most of ag waste and manure). Due to the substantial cost of laying gas pipeline to biogas plants, only biomass available within 80 km of existing gas lines is deemed available for bio-methane for the gas grids, amounting to 38 EJ on a global scale. With a conversion efficiency of 60%, this amounts to 23 EJ available to all sectors. **3)** Based on internal study identifying the amount biomass needed to cover the non-electrifiable energy need of global sectors. Sectors (EJ): Shipping (30), Aviation (30), Road transport (30), Electricity balancing (30), Peak load heating (50), Industry (50), Plastic (90), Cement (30), Steel (20).**4)** 16% could be perceived from the industry taking a first-mover role into biofuels, being able to economize from customers' higher willingness to pay or being imposed stricter regulatory incentives than the other industries. However, due to the additional costs in using biomethane for shipping from liquefaction, the loss of methane and additional emissions from methane slip, we expect lower uptake for shipping on biomethane **5)** The fastest growth rate observed, that of US Biodiesel from 2003-2016², was used for the early roll-out from 0-1,5 EJ for maritime of each biofuel. To represent a slower global roll-out after 1,5 EJ for maritime, the growth rate of global ethanol from 2003-2016 was used above 1,5 EJ. US Biodiesel followed logarithmic growth by formula 10^(log(x)+0,152). **6)** Standard plant size: 10 kton methane/year

Biomethane's availability to shipping is highly dependent on competition with other sectors, the expansion of gas grids, and the availability of a certificate trading scheme

Subject	Risks	Potential risk mitigations
Feedstock	▪ Biomass competition with other industries and other fuels is unclear, and could drive up feedstock costs	▪ Refine assessment of biomass availability and sector competition on a regular basis
Production	▪ Rapid roll-out of biogas plants will be needed to new demand from various sectors ▪ Competition from other sectors will likely limit supply for shipping ▪ Falling electricity prices will push methane out of electricity production and onto the fuel market	▪ Availability of EPC resources for rapid roll-out ▪ Consider expansion, upgrading and connection to grid of already existing plant ▪ Boost production with e-hydrogen via methanation
Logistics	▪ Defined biomass availability assumes proximity of bio-methane plants to gas grids; however, some gas grid expansions may be needed to make biogas available as a fuel (Depending on how certificate trading scheme is designed)	▪ Study expansion of national gas infrastructures ▪ Study potential for local pooling and liquefaction close to ports
Regulatory	▪ Regulation needed to guide sustainability validation of biofuels ▪ Methane loss & slip needs to be understood and reduced through regulation ▪ As bio-methane will often be transported in gas grids along with natural gas, regulation must uniformly acknowledge trading of biomethane certificates	▪ Measurement campaigns aimed to understand all source of emissions throughout the supply chain ▪ Establish technology improvements to ensure fail-safe design ▪ Make results public to facilitate understanding and actions from regulators and plant owners

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E-methane will need financial measures in order to be cost competitive with fossil alternatives

Highlights from cost analysis of e-methane pathways

- In all years, the <u>cost</u> of e- methane is ca. 3 - 8 times higher than the <u>price</u> forecast for LSFO at 10 USD/GJ
- Production cost is projected to decrease by 10% p.a. and reach 36 USD/GJ by 2050.
- The cost of e-methane is sensitive to 3 primary factors:

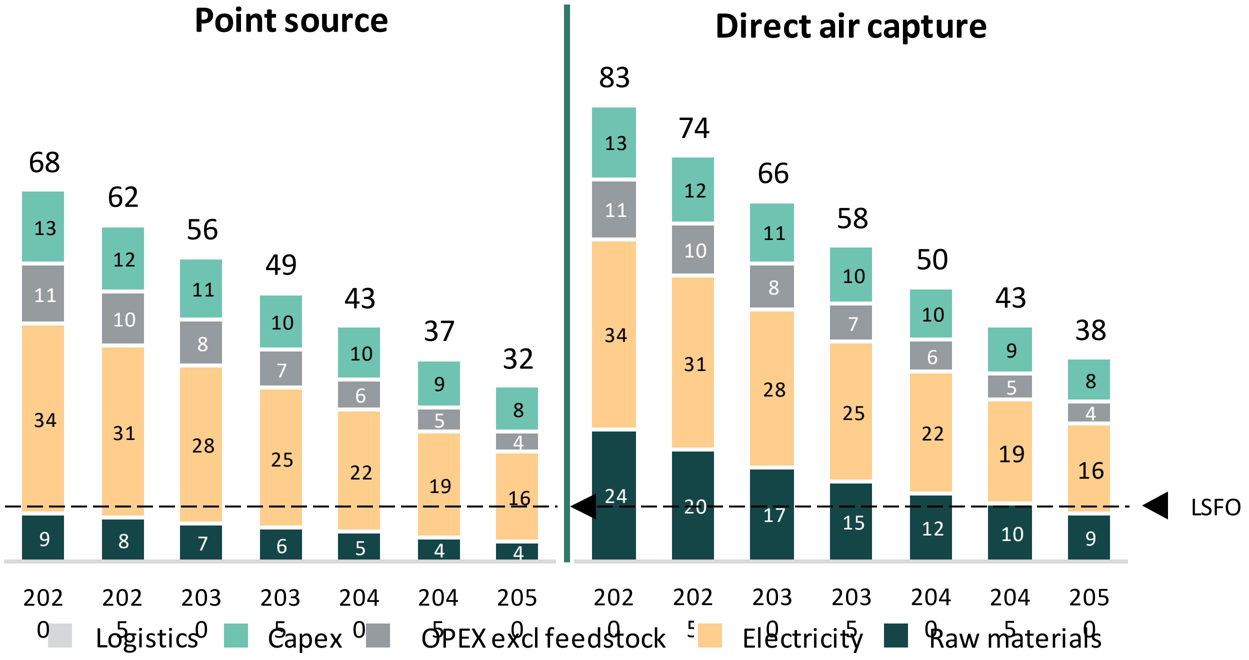
1. Renewable electricity cost determines the largest portion of production cost. The intermittent unavailability of RES creates requirements for power buffering or equipment turndown. Since the RES cost differs between regions, it is a determining factor for the location of e-methane plants.
2. When point sources become scarce, the cost of e-methane will also depend significantly on the cost of CO_2 from direct air capture (due to limited availability of renewable CO_2 point sources).
3. The cost effectiveness of methane production depends critically on economies of scale, whereby larger plants are far more economical. Since the local availability of CO_2 (certified as renewable) is expected in short supply, near-term e-methane plants will be difficult to scale and thus achieve cost-effective production.

E-methane will need financial measures in order to be cost competitive with fossil alternatives

E-methane pathway costs, at port

Weighted global average[1]

USD/GJ



1) Assuming 40 % from lowest cost region, 30 % from 2nd lowest, and 10% from 3-5th.

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E-methane Supply is limited by large-scale supply of certified CO_2 and by developments in renewable hydrogen production

Subject	Risks	Milestones to Implementation
Feedstock	▪ Reliable supply of CO_2 certified as renewable, at the scale required to make methane plants of competitive capacity. ▪ Optimizing and scaling of hydrogen production by electrolysis, in turn dependent on availability of RES	▪ Scale-up of renewable CO_2 supply chain, initially with biogenic sources and later direct air capture; this CO_2 feedstock additionally requires the development of logistics infrastructure for distribution. ▪ Scale-up of RES capacity to meet global demand and be available for shipping: address land use policies, labor, and infrastructure; secure growth of battery materials supply chain (or other solutions to address variable electricity supply). High-paced growth of Electrolysis sector: manufacturing and supply chain.
Production	▪ Production site location with proximity to RES & CO_2 feedstocks ▪ Improvements to conventional methanol process: capturing off-gas, catalysts to accommodate reactor water content, etc.	▪ New commercial electro-methane plants operating on low-cost RES and with adequate proximity both to relevant ports and to centralized CO_2 supply. ▪ Scale-up of electro-methane infrastructure globally.
Logistics	▪ Expansion of ports supplying liquid methane	▪ Establish green corridors with sufficient critical mass of supply at ports.
Regulatory (Supply)	▪ Redesign to capture production off-gas normally not captured in conventional SNG synthesis (off-gas is normally used as fuel and, if re-used for synthesis, contains impurities to be removed) ▪ Production off-gas would create emissions if used as fuel. ▪ Certification for which CO_2 point sources are considered renewable.	▪ Monitoring of (and regulatory standards for) restricting methane emissions. ▪ Implement regulatory standards to certify the emissions associated with feedstock.

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Commercially available designs and technologies; methane slip to be addressed by regulation and further adoption of near-term technologies and solutions

Subject	Considerations	Potential risk mitigations
Energy density and volume	• Requires around 2 times the volume compared to VLSFO for the same energy content with additional volume and weight needed for the required tank and fuel systems	• Tradeoffs are well understood as LNG-fueled vessels have already been built and are in operation • Depending on vessel type, size and operational profile, optimize speed and range requirements or accept more frequent bunkering
Fuel Supply & Storage	• Stored in pressurized Type-C tank at around 4-bar or fully-refrigerated at atmospheric pressure (prismatic/membrane stainless steel) – cryogenic materials needed • Cryogenic equipment needed for supply of fuel to energy converters • Boil-off gas can be managed using Type-C tank pressure accumulation, reliquification plants or gas consumers • Low- and high-pressure fuel systems available for 2-stroke engines; only low-pressure for 4-stroke	
Regulation	• Regulated by IGF Code as a low flashpoint fuel • Onboard methane emissions are currently unregulated	• Methane to be a regulated vessel emission with required levels set to promote further technology development and adoption of low-methane slip solutions • Regulation starts to be considered at EU level and currently under discussion at IMO

Sources: ABS "Sustainability Whitepaper: LNG as Marine Fuel" June 2020
MAN Energy Solutions "Managing methane slip"

Commercially available designs and technologies; methane slip to be addressed by regulation and further adoption of near-term technologies and solutions

Subject	Considerations	Potential risk mitigations
Energy Converters	• Dual-fuel LNG engines are commercially available including conversion options (different engine technologies outlined in Slides 17-18) • Requires a small proportion of pilot fuel (1.5-5%), for example MGO, dependent on engine bore-size (higher proportion in smaller engines) • LNG-powered fuel cells are possible, but not yet commercially available	

Emissions	• Tank-to-wake CO_2 emissions reduced 20-25% compared to fuel oils
	• LNG is a cleaner fuel that results in less air pollutant emissions
	  • 90-99% SOx reduction compared to HFO Tier II
	  • 90% reduction of particulate matter compared to HFO Tier II
	  • NOx Tier III to be met with EGR/SCR
	• Methane slip decreases tank-to-wake GHG emission reduction to 5-20% with a global warming potential (GWP) around 30 times CO_2 over 100 years
	• The impact of methane slip on GHG emissions can vary widely based on engine technology, engine load, machinery plant configuration and GWP timeframe
	• Methane slip emissions documented at fixed loads as part of test bed performance reports, however, actual onboard emission measurements are limited
	• Speed reduction and lower engine loads due to energy efficiency regulations could lead to operation at non-optimal loads with higher methane slip for some technologies
		• Engine combustion optimization and after-treatment technology developments to reduce methane slip, on low-pressure Otto 2-stroke and 4-stroke engines (electronic combustion control, EGR and oxidation catalysts)
		• Battery hybrid or shaft generator can be used to minimize methane slip from auxiliary gensets; shore power connection in port
		• Carry out experiments to measure onboard methane emissions under realistic operational conditions
		• Optimal machinery dimensioning and operation (energy management) to avoid low engine loads where methane slip is higher

Sources: ABS “Sustainability Whitepaper: LNG as Marine Fuel” June 2020
MAN Energy Solutions “Managing methane slip”

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LNG and bio-/e-methane well-to-wake emission calculations and references

Center Approach

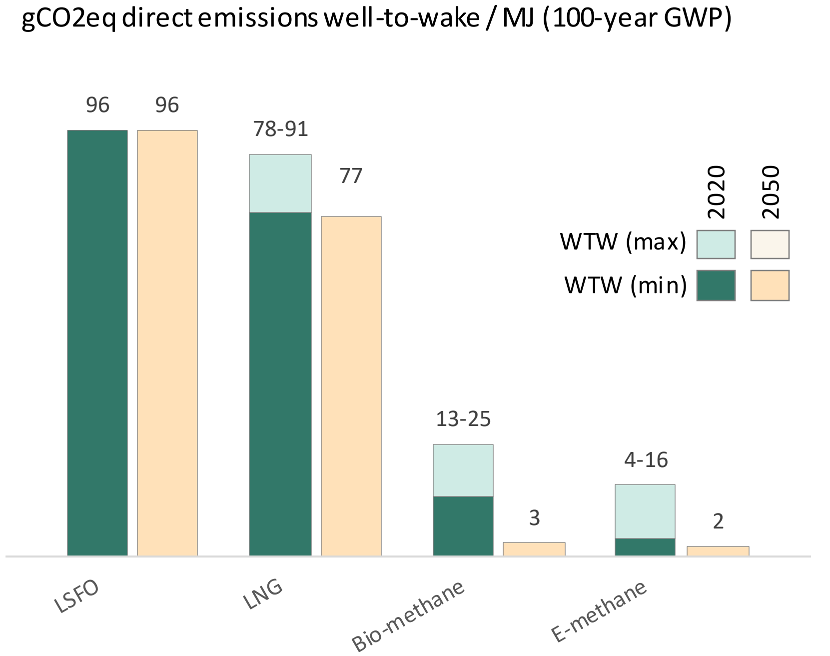
- Review of publicly available information and reports
- Collection of input from partners
- Synthesize into needed NavigaTE inputs

Notes

- Due to emission variance depending on onboard engine technology and operation, in particular the associated methane slip, a range for WTW emissions is given
- The emission associated with pilot fuel is excluded from WTW emission values, however, its impact assuming LSFO as the pilot fuel is provided
- Current emission calculations and NavigaTE inputs are based on a 100-year global warming potential (GWP), however, 20-year GWP will be incorporated in the future
- 2050 emission values assume no methane slip due to improved engine and after-treatment technology or the use of fuel cells

References

- International Council on Clean Transportation (ICCT) "The climate implications of using LNG as a marine fuel" February 2020
- Sphera "2nd Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel – On behalf of SEA-LNG and SGMF" 15.04.2021
- American Bureau of Shipping (ABS) "Setting the course to low carbon shipping: View of the value chain"



Pilot fuel (1-2%) is needed. Using LSFO, this equals up to an additional 2 gCO_2eq/MJ.

Assumption	Value
Emission Factor – LNG (gCO_2/g fuel)	2,75
100-year Global Warming Potential – Methane	31
Lower calorific value (kJ/g LNG)	48
Lower calorific value (kJ/g Methane)	50

Engine Type	Fuel Consumption (g/kWh)	Methane Slip (g/kWh)	WTT Emissions (gCO_2e/MJ)	WTW Emissions (gCO_2e/kWh)	WTW Emissions (gCO_2e/MJ)
HPDF 2-stroke	135	0,25	19,6	506	78
LPDF 2-stroke*	145	2,25	19,6	605	87
LPDF 4-stroke	165	3,5	19,6	717	91

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Note: The final emission values determined based on both publicly available references and internal partner input
* Latest versions of the LPDF 2-stroke engines with exhaust gas recirculation (EGR) can reduce methane slip up to 50%
HPDF: High-pressure dual-fuel
LPDF: Low-pressure dual-fuel

Engine-specific GHG emission calculations have been used to estimate a fleet-level emission time-dependent value for NavigaTE

- In order to estimate the TTW emissions (gCO_2e/MJ) at a fleet level, the percentage of main energy converters on LNG-fueled vessels was used to calculate a weighted average emission value
- 2020 values are based on ships in operation and on order as of mid-2018 from ICCT's "The climate implications of using LNG as a marine fuel"
- Emission values for subsequent years are scaled based on potential uptake of more efficient technologies like HPDF two-stroke engines and fuel cells

		% of main converter type for LNG-fueled vessels				
Engine Type	**WTW (gCO2e/MJ)**	**2020**	**2025**	**2030**	**2035**	**2040**
HPDF 2-stroke	58	12%	18%	27%	35%	37%
LPDF 2-stroke	67	7%	7%	5%	4%	4%
Steam/Gas Turbine	57	37%	30%	23%	16%	9%
LPDF 4-stroke	71	45%	45%	40%	35%	30%
Fuel Cell	57	0%	0%	5%	10%	20%

NavigaTE Input	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
TTW Emissions (gCO2e/MJ)	64	59	58	58	58	57	57

ICCT: International Council on Clean Transportation
HPDF: High-pressure dual-fuel
LPDF: Low-pressure dual-fuel