New Gases Value Chains Study

Final report – strictly confidential -

10 July 2024

Table of contents

Project Objectives

Built an objective assessment on new gases

WP1: New gases value chains compared to the LNG ones

Technical descriptions & efficiencies estimate on every step of the value chain (LNG, BioLNG, e.methane, blue/green H2, LH2)

Analysis of various CO_2 sourcing routes (biogenic and non-biogenic) and hydrogen production options

WP2: Develop new gases analytical modelling tool, for 2030, 2040 and 2050:

Construction of an adjustable and configurable tool to calculate LCOx and delivered costs and other KPIs.

Based on recognized data sources
Transparent cost model, re-usable with transparent asssumptions

Work Package 3 - Perform regional analysis for Australia, Europe, the US and North Africa

Value chains intercomparison, production capacity by region or key countries and assessment of inter-regional flows, including transportation costs for 8 various corridors.

Export regions: Middle East, North Africa, Australia, US Gulf Coast
Import regions: Europe, Japan

This study is...

- **Objective assessment**
- **Initial asesssment,**
- **Based on recognized sources**

It is not...

As for now…

- It won't be published
- We are not creating a common view within GIIGNL
- It’s not an advocacy

Table of contents

Overall methodology approach

Data based on authoritative sources, transparent model

1. Review of the existing publications, clean fuel databases and assumptions

- To ensure the quality of results, Guidehouse has analysed various external and internal resources on the subject, collecting information for the future benchmarking.
- Review of existing and upcoming technologies and their TRL across the new gas value chain, using sources such as IEA and IRENA, combing with internal view of the experts.
- Available databases and publications have been carefully reviewed with assumptions made where applicable.

2. Build-up of the model to represent results

- Configuration of the modelling tool for new gases with the view on 2030, 2040 and 2050.
- Feeding the model with collected input information coming from the literature review and performing analyses for:
    - Efficiency losses across the value chain for each gas
    - CO2 emissions and CO2 emissions abated
    - Calculation of LCOx and delivered quantities across the geographies
- Making necessary assumptions to deliver the results*

3. Exchange with experts

- Internal GH experts have been involved to share knowledge and best practices to perform the necessary calculations.
- List of interview questions sent to the GIIGNL members to help closing the data gap.
- Regular exchange with core GIIGNL team, reviewing the progress and setting next steps.

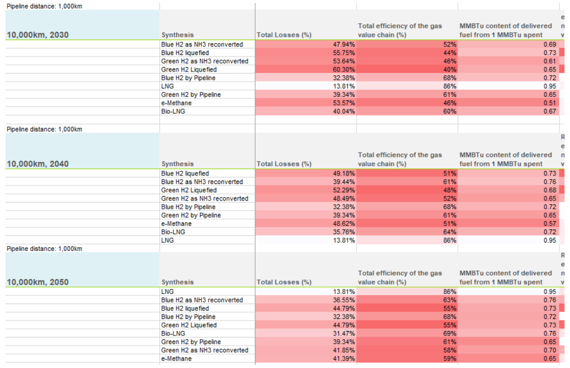
* See the next slides for assumptions made during the study and in the data workbook

Deliverables summary

The project have ensured 3 main deliverables.

WP 1	→	WP 2	→	WP 3

Assess new gases technical value chains compared to the LNG one: technical descriptions & efficiencies estimate, analysis of various CO_2 sourcing routes (biogenic and non-biogenic) and hydrogen production options.



Pipeline distance: 1,000km

10,000km, 2030	Synthesis	Total Losses (%)	Total efficiency of the gas value chain (%)	MMBTu content of delivered fuel from 1 MMBTu spent
	Blue H2 as NH3 reconverted	47.94%	52%	0.69
	Blue H2 liquefied	55.75%	44%	0.73
	Green H2 as NH3 reconverted	53.64%	46%	0.61
	Green H2 Liquefied	60.30%	40%	0.65
	Blue H2 by Pipeline	32.38%	68%	0.72
	LNG	13.81%	86%	0.95
	Green H2 by Pipeline	39.34%	61%	0.65
	e-Methane	53.57%	46%	0.51
	Bio-LNG	40.04%	60%	0.67

Pipeline distance: 1,000km

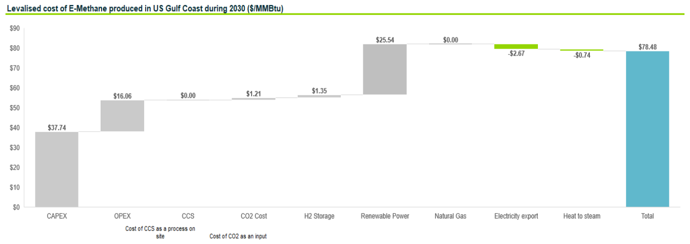
10,000km, 2040	Synthesis	Total Losses (%)	Total efficiency of the gas value chain (%)	MMBTu content of delivered fuel from 1 MMBTu spent
	Blue H2 liquefied	49.18%	51%	0.73
	Blue H2 as NH3 reconverted	39.44%	61%	0.76
	Green H2 Liquefied	52.29%	48%	0.68
	Green H2 as NH3 reconverted	48.49%	52%	0.65
	Blue H2 by Pipeline	32.38%	68%	0.72
	Green H2 by Pipeline	39.34%	61%	0.65
	e-Methane	48.62%	51%	0.57
	Bio-LNG	35.76%	64%	0.72
	LNG	13.81%	86%	0.95

Pipeline distance: 1,000km

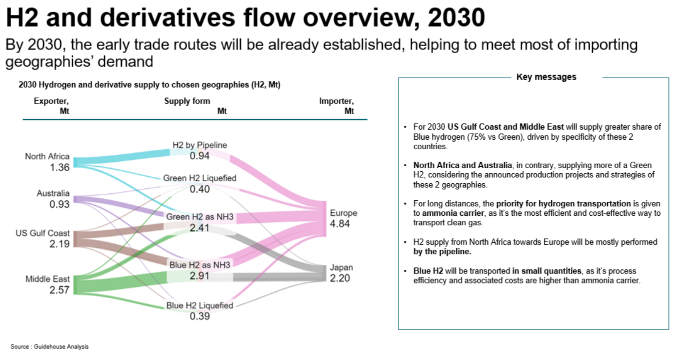
10,000km, 2050	Synthesis	Total Losses (%)	Total efficiency of the gas value chain (%)	MMBTu content of delivered fuel from 1 MMBTu spent
	LNG	13.81%	86%	0.95
	Blue H2 as NH3 reconverted	36.55%	63%	0.76
	Blue H2 liquefied	44.79%	55%	0.73
	Blue H2 by Pipeline	32.38%	68%	0.72
	Green H2 Liquefied	44.79%	55%	0.73
	Bio-LNG	31.47%	69%	0.76
	Green H2 by Pipeline	39.34%	61%	0.65
	Green H2 as NH3 reconverted	41.85%	58%	0.70
	e-Methane	41.39%	59%	0.65

Develop new gases analytical modelling tool, including forecasting for 2030, 2040 and 2050: construction of an adjustable and configurable tool to calculate LCOx and delivered costs

With data workbook



Assess new gases technical value chains compared to the LNG one: technical descriptions & efficiencies estimate, analysis of various CO_2 sourcing routes (biogenic and non-biogenic) and hydrogen production options.



Overall Report

Table of contents

New gases value chain efficiency and emissions intensity

-Benchmark -

LNG E-methane Hydrogen e-Ammonia

Technology overview - summary

Overall, technology readiness for production of most clean gases is considered as mature, with improvements foreseen in energy efficiency and cost reductions.

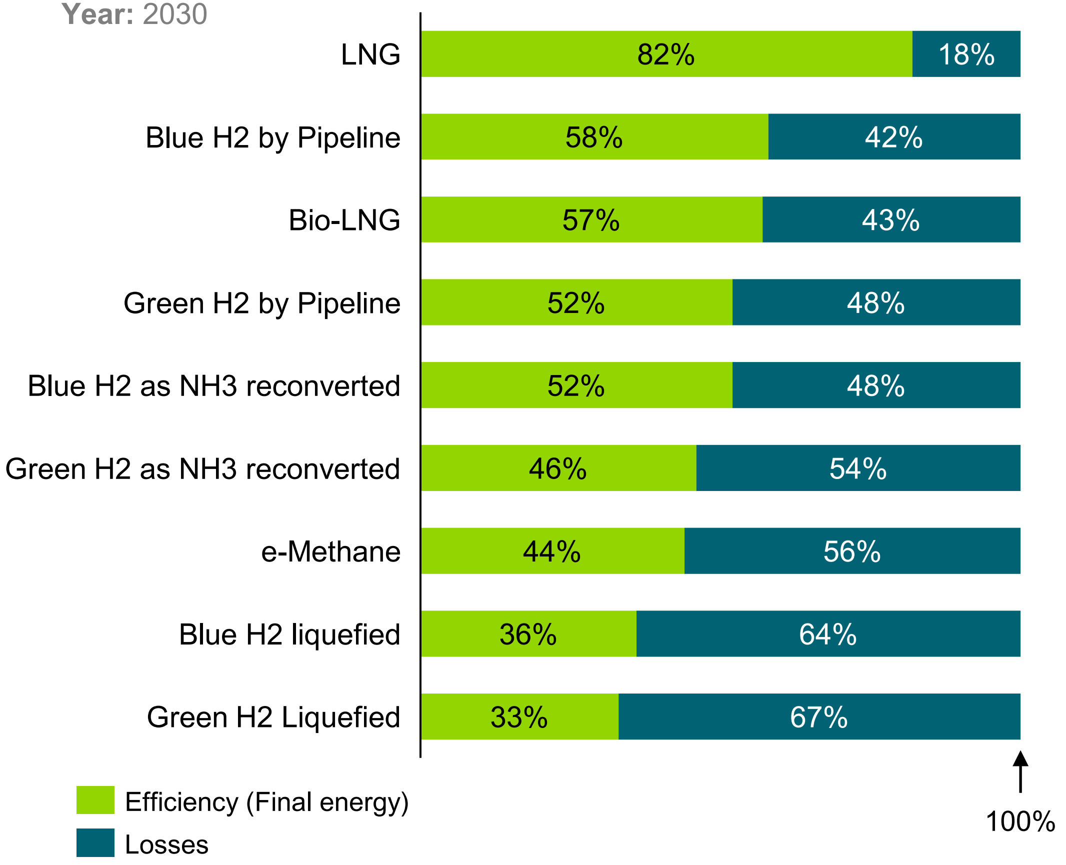
Gas		Technology maturity	Expected development	Challenges
LNG	TRL 8 - 9	• Already well- established value chain with mature technology.	• Foreseen improvements in efficiency and energy consumptions for Liquefaction process, which is currently very energy intensive. • Emergence of new technologies, such as FLNG, allowing to considerably reduce CAPEX of onshore construction and gaining flexibility of the process.	• Size of the platform required to build FLNG has to be sufficient to accommodate all necessary equipment, staying stable in the harsh marine conditions. • High quality insulation and heat recovery are required to prevent losses.
Bio-LNG	TRL 7 - 9	• Relying on existing available LNG infrastructure, the technology is mostly mature.	• Bunkering infrastructure is expected to roll-out significantly in the coming years. • Improvements in liquefaction process by using high pressured storage tanks.	• Considerable investments required to scale up production with required infrastructure. • Requirement of better standardization of the process technology. • Liquefaction of bio-LNG consumes 2x more energy than “standard” liquefaction.
E-methane	TRL 6	• Value chain of e-methane is mature with the one from LNG, mostly relying on the existing infrastructure, especially for its transportation and storage.	• DAC and CCUS technologies need further scaling up • Methanation process	• Availability of P2X technology and scale up of clean electricity availability specifically for synthetic fuel production. • Feedstock availability of biogenic CO2 might be not sufficient in all geographies to produce e-methane.
Hydrogen	TRL 8	• Overall technologies to produce, transport, store and distribute blue and green hydrogen are viewed as mature.	• Improvements are foreseen for energy efficiency and reliability gains in electrolysis. • High-capacity hydrogen storage (underground H2 Storage and new fuel cells are currently researched.	• Availability of clean electricity feedstock and associated costs of production. • Availability of precious materials required by high efficiency electrolysis (PEM. SOEC) and associated costs. • LH2 technology
E-ammonia	TRL 7	• Mature technology across whole value chain till the last step of reconversion, where ammonia cracking is required, being very energy consuming.	• Low temperature ammonia cracking with cost-competitive materials.	• Availability of P2X technology and availability of bunkering infr. • Energy intensive process of reconversion might not be overcome. • High toxicity

Gas value chain round trip efficiency overview

E-methane and liquefied hydrogen suffer the most energy losses across the value chain in 2030

Round trip efficiency throughout the gas value chains studied (%)

Shipping distance: 35,000km
Pipeline distance: 3,000km
Distribution distance: 200km
Year: 2030



Source : Guidehouse Analysis, see detailed losses in Sankey Diagram slides

Key messages

- LNG and piped hydrogen are the gases displaying **the highest efficiency levels.**
- E-methane less efficient that the other methane-based value chains because of its current technology development status and corresponding production efficiency for methanation in 2030. **Technology improvements and economies of scale are expected to make e-methane more efficient over time**, which is presented in later slides.
- Green and blue liquified hydrogen incur total **losses of over 64%** in this example, largely due to energy intensive compression and liquefaction steps. Losses in the hydrogen value chain are largest at the liquefaction step due to the energy required to cool hydrogen to its boiling point of −253°C.
- Large losses are also incurred from the boil-off of liquid hydrogen, which are particularly minimal at a distance of **10,000 km (4.7%)** but much higher at **35,000 km (15.4%)** at a boil off rate of 0.326% per day.[3]
- Hydrogen transported as ammonia is more efficient than liquefied hydrogen **at all ranges in 2030.** The most energy intensive part of the liquid ammonia value chain is cracking (~25% losses).
- Hydrogen delivered by pipeline is more efficient than shipping as ammonia **up to around 3,500km**, around the distance between the UAE and Greece over land.

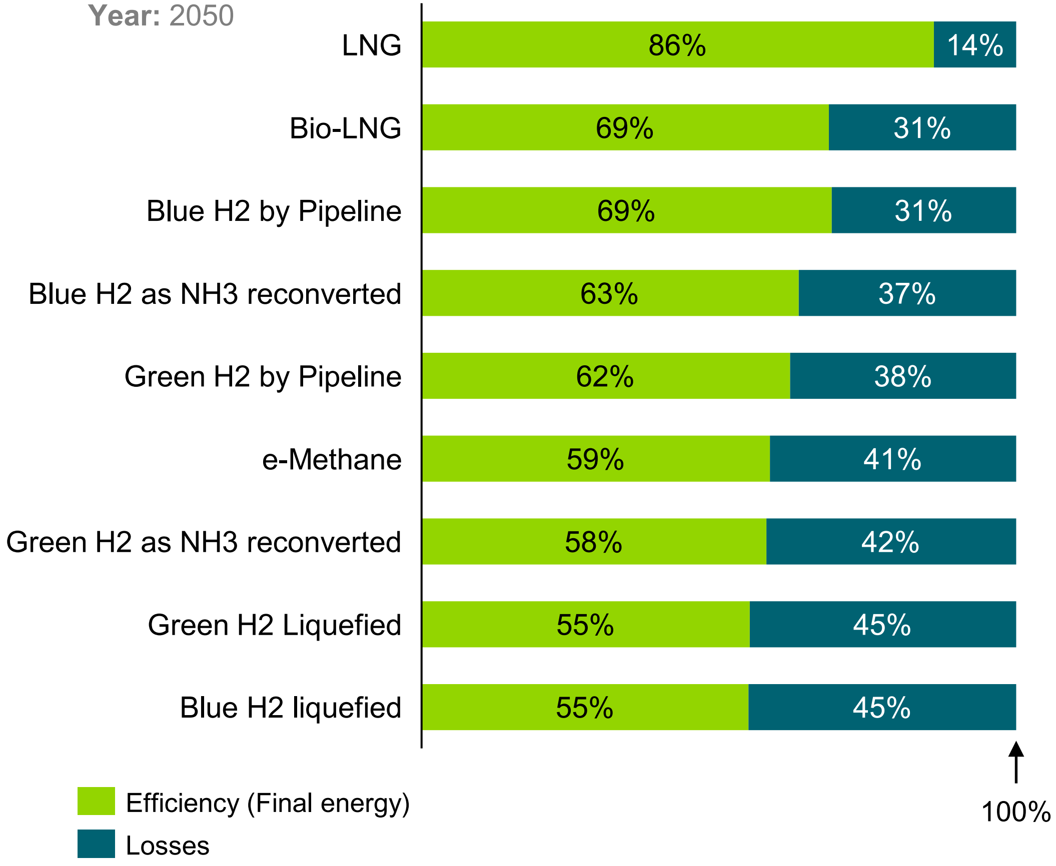
[1]A wide range of efficiency assumptions can be used for different technologies making up these gas value chains, the ones selected are 2030 oriented. Certain technologies are expected to improve over time.
[2]Efficiency of e-methane and clean ammonia
[3]Hydrogen boil-off rate

Gas value chain round trip efficiency overview

E-methane and liquefied hydrogen value chains suffer the most energy losses across the value chain

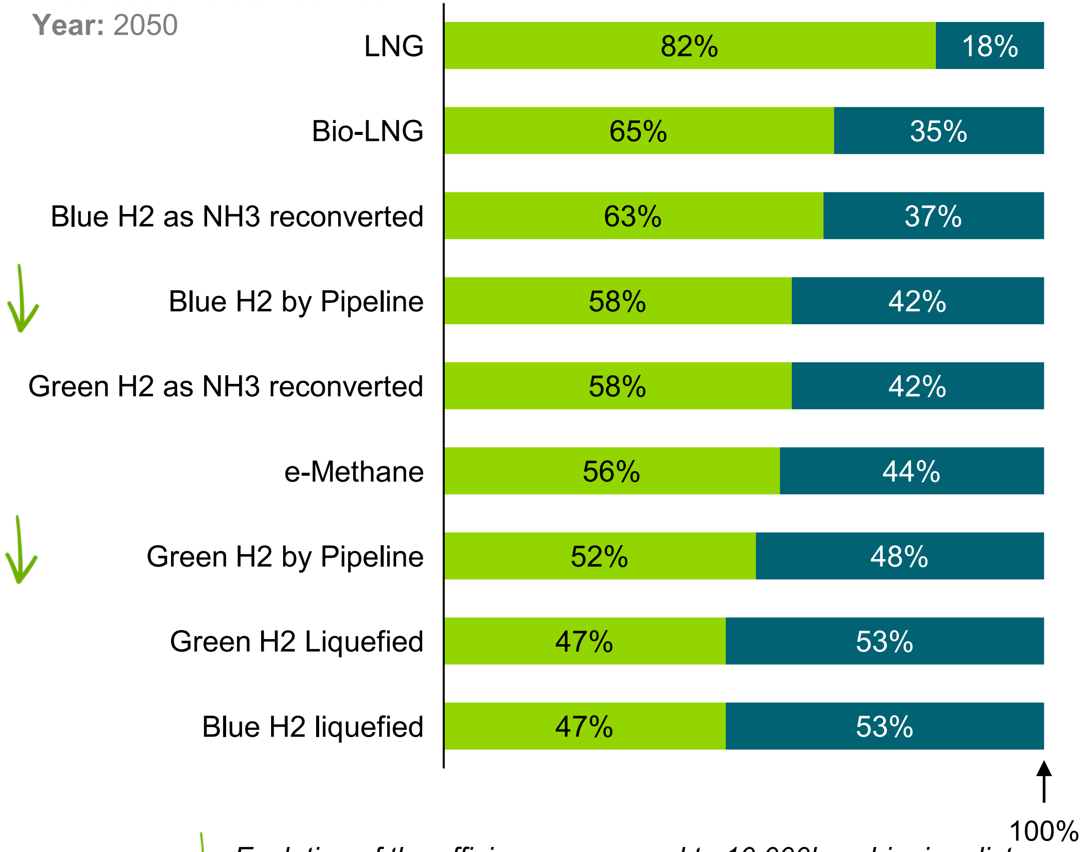
Gas value chain round trip efficiency at short distance in 2050 (%)

Shipping distance: 10,000km
Pipeline distance: 1,000km
Distribution distance: 200km
Year: 2050



Gas value chain round trip efficiency at long distance in 2050 (%)

Shipping distance: 35,000km distance between US Gulf Coast and Japan
Pipeline distance: 3,000km
Distribution distance: 200km
Year: 2050



Evolution of the efficiency compared to 10 000km shipping distance

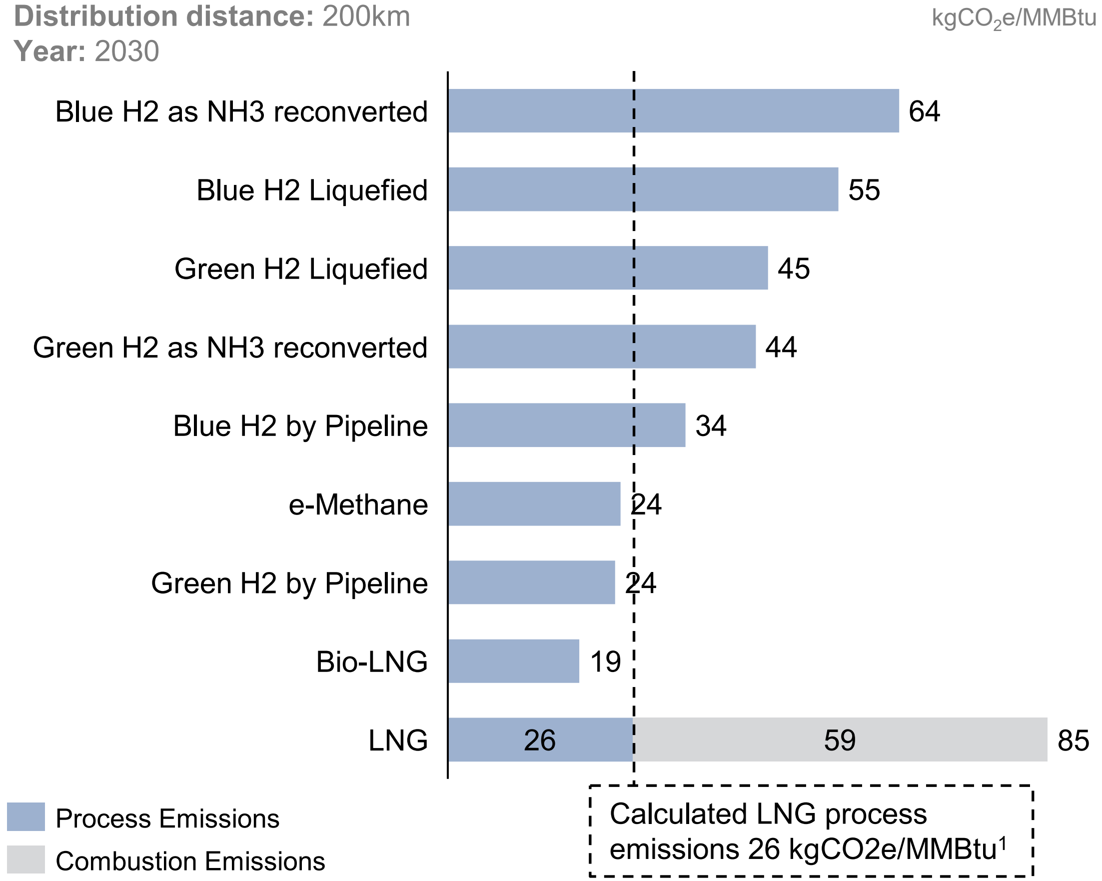
Notes: Guidehouse Analysis, Technology efficiencies are assumed to be low relative to possible improvements. Liquid hydrogen incurs much larger losses to boil-off during shipping than methane and ammonia-based fuels, making longer distances much more inefficient.

Gas value chain CO2e emissions overview

Most new gas value chains have higher process emissions than a state-of-the-art LNG value chain, but full emissions are lower

Emissions intensity of the gas value chains studied ($kgCO_2e/MMBtu$)

Shipping distance: 10,000km
Pipeline distance: 1,000km
Distribution distance: 200km
Year: 2030



Source : Guidehouse Analysis, stepwise emissions shown in Sankey Diagram slides.

Key messages

- Many new gas value chains such as liquefied hydrogen, clean ammonia cracked into hydrogen, and e-methane emit more process CO_2 / MMBtu of input due to having **more energy intensive value chains.**
- The total carbon intensity of the value chain depends largely on the carbon intensity of **power used** for compression, liquefaction, cracking etc. this example is using the average grid intensity of ERCOT in Texas for 2023 (0.380 $kgCO_2/kWh$) for the export value chain steps, and France for the importing value chain steps (0.038 $kgCO_2$ /kWh).[2]
- For the methane-based value chains, it is assumed gas flowing through distribution and storage pipelines are used to power compressors. For the case of bio-LNG and e-methane, consumption of this gas for compression energy **does not lead to CO_2 emissions** as the combustion of the fuel is considered carbon neutral.[3] Hydrogen and ammonia compressors are assumed to be powered by **external electrical power** from the grid due to pour energy efficiency of hydrogen used for gas compression.
- Electrolysers used for green hydrogen, green ammonia, and e-methane production are assumed to be **powered by co-located renewables**, which are on average 10x less carbon intensive than the Texas grid for example (0.026 $kgCO_2/kWh$).
- Leakage of hydrogen through the value chain is **much higher than methane,** making up 10% of total CO_2e emissions **over a distance of 10,000km.**[4]

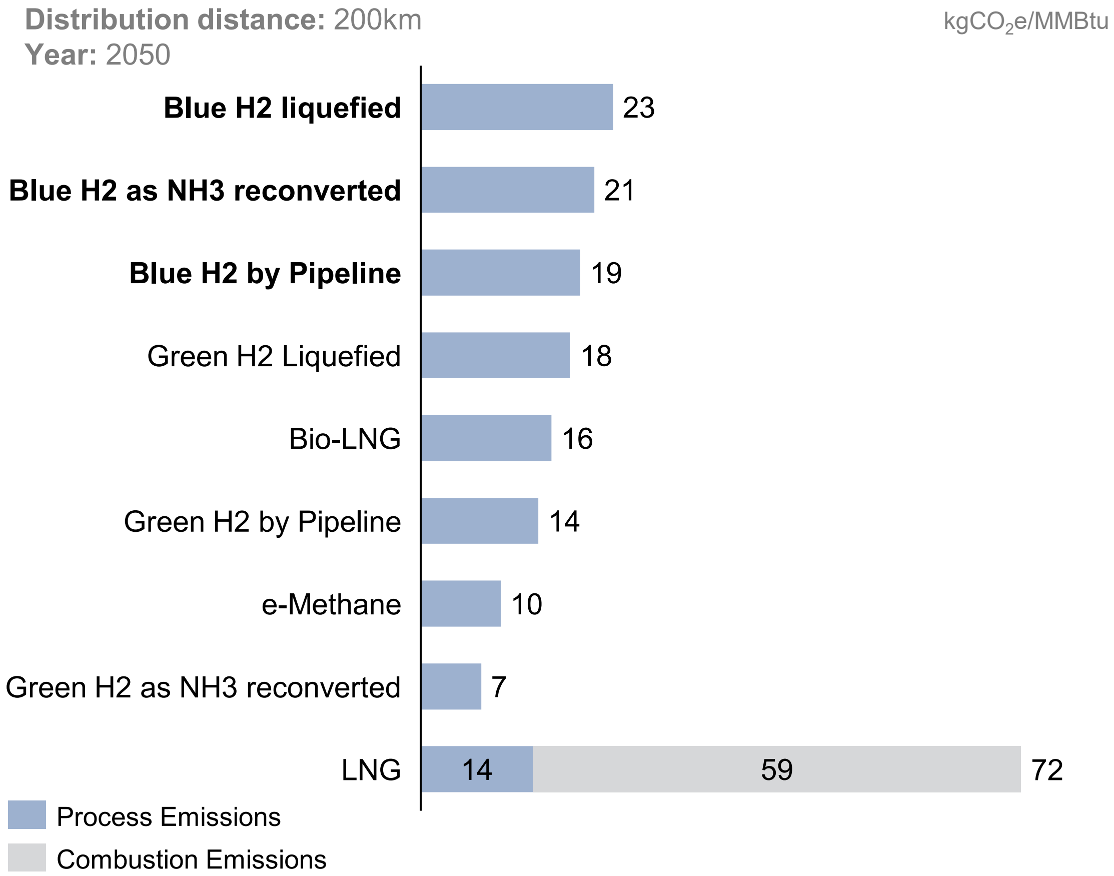
[1]Upstream methane emissions of natural gas assumed to be 1% - general US average. GWP of 30 used for CH4 as per IPCC 6. State of the art liquefaction efficiency of 91% assumed.
[2]2023 carbon intensity of ERCOT
[3]Combustion of new gases in scope is considered to be carbon neutral. For e-methane and bio-LNG, it is assumed that an equivalent amount of CO_2 that is released during combustion is required as an input into the process, which requires removing or preventing CO_2 from entering the atmosphere, making the combustion carbon neutral.
[4]Hydrogen GWP of 11.6 assumed. Nature

Gas value chain CO_2e emissions overview

Most new gas value chains have higher process emissions than a state-of-the-art LNG value chain, but full emissions are lower

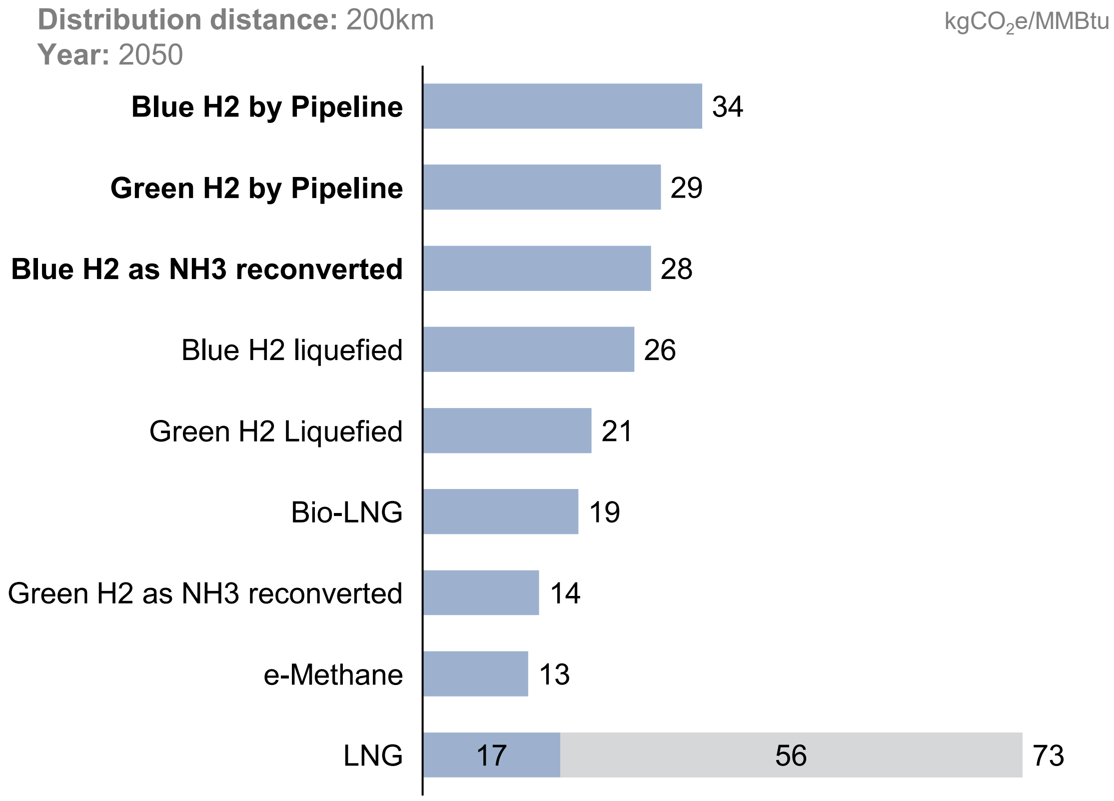
Emissions intensity of the gas value chains studied (kgCO_2e/MMBtu)

Shipping distance: 10,000km
Pipeline distance: 1,000km
Distribution distance: 200km
Year: 2050



Emissions intensity of equivalent delivered fuel energy (kgCO_2e/MMBtu)[1]

Shipping distance: 35,000km
Pipeline distance: 3,000km
Distribution distance: 200km
Year: 2050



↑ *Evolution of the efficiency comparted to 10 000km shipping distance*

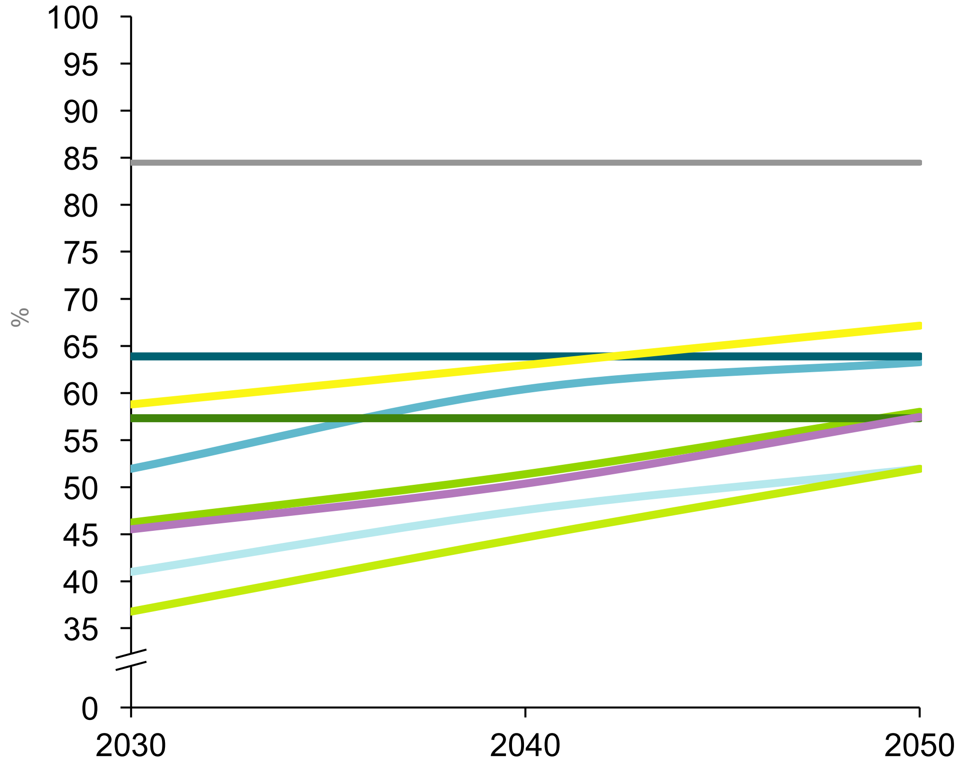
Source : Guidehouse Analysis, stepwise emissions shown in Sankey Diagram slides. Carbon intensity of export value chain is based on US Guld Coast and import value chain based on France.

Effect of Efficiency and CO2 Improvements

Green H2 liquefied is expecting to see the biggest increase in efficiency (15%) from 2030-2050

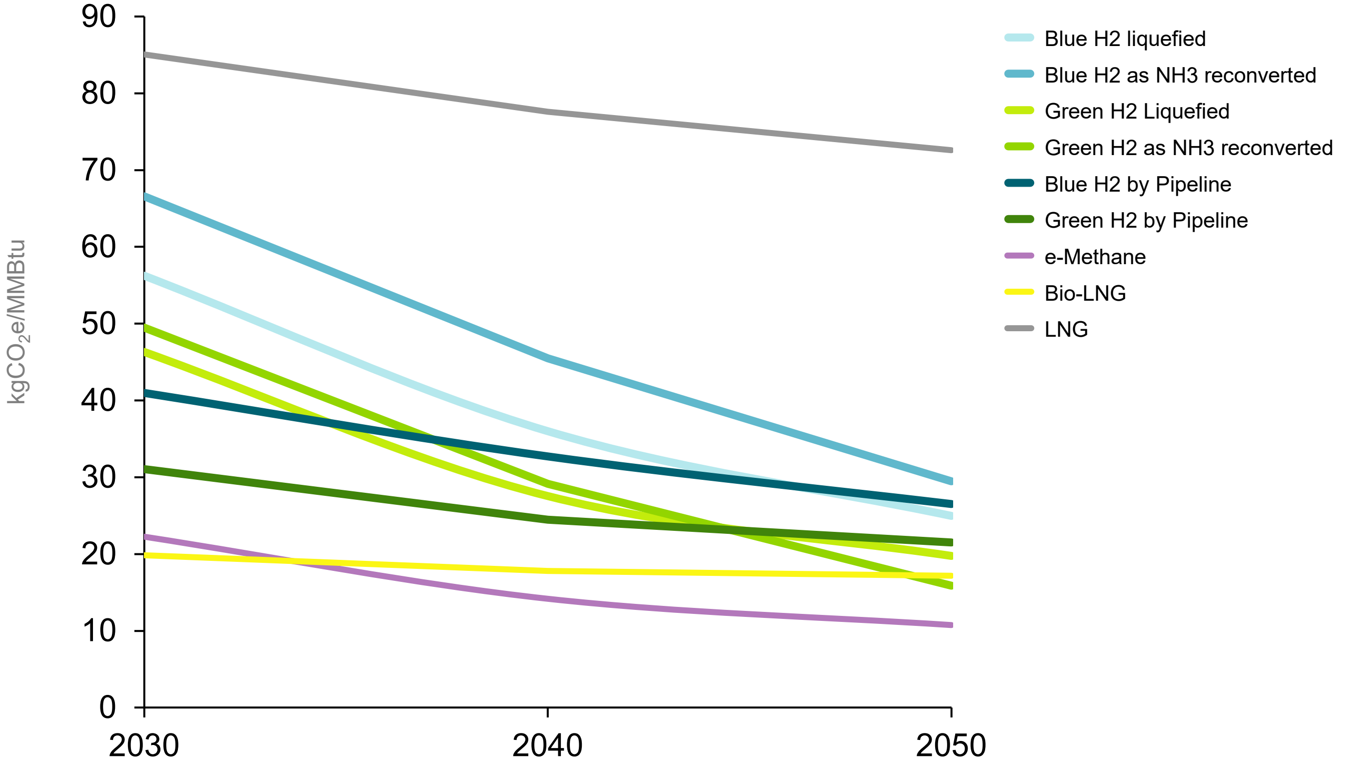
Efficiency of gas value chains over time at an average distance (%)

Shipping distance: 20,000km
Pipeline distance: 2,000km
Distribution distance: 200km



Emissions intensity of the gas value chains studied (kgCO$_2$e/MMBtu)

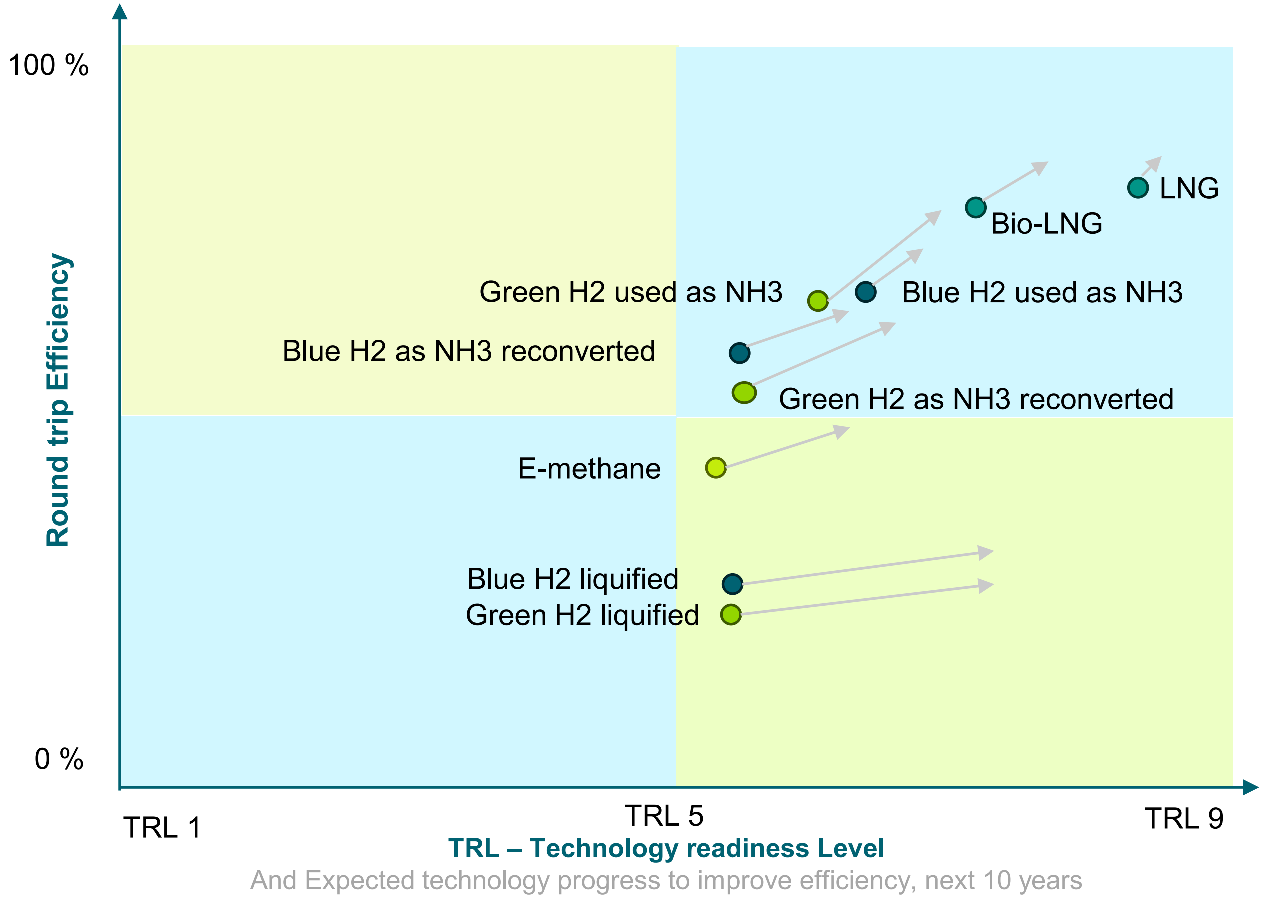
Shipping distance: 20,000km
Pipeline distance: 2,000km
Distribution distance: 200km



Conclusion: over time efficiencies of most gas value chains increase depending on technology improvements. CO2 emissions decrease along with grid intensities and upstream emissions factors in each country. **All gas value chains are less carbon intensive than LNG.** Pipeline efficiency is not expected to improve beyond 2030 based on the assumptions made. Carbon intensity of export value chain is based on US Guld Coast and import value chain based on France.

Efficiency and technology maturity

High improvement are expected technology maturity and scalability, but complex chain with multi-conversions won't have efficiency >50%



Source : Guidehouse Analysis. H2 transported via pipelines are not assessed at this stage

Key messages

- Regarding the future progress of the different technologies based on the analysis, traditional fuels and mature technologies such as LNG but also Bio-LNG will see less technological progress and therefore less room for improvement of the efficiency levels.
- The **liquefaction** being an already mature technology, the expected improvements will not be significant. LH2 is not foreseen as a major way of long transportation .
- The **electrolysis** process is also expected to evolve in the coming years with the introduction of new technologies able to provide higher efficiency rates. **Scalability will be improved** (ALK, PEM)
- The **steam reforming** technology being mature, blue hydrogen could see some progress in terms of CCU Carbon capture improvements in the coming years with the biggest challenge being the reduction of energy losses on the transport process or the ammonia cracking stage.

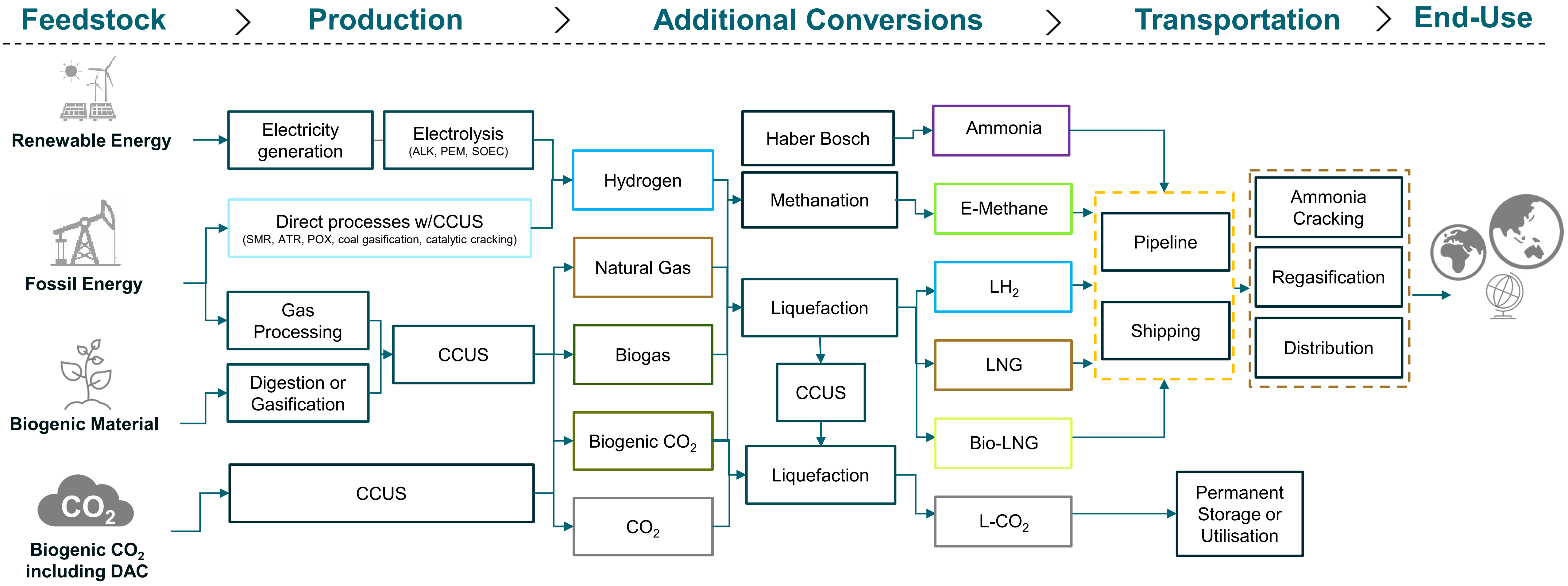
New gases value chain efficiency and emissions intensity

- Analysis of the value chain per gas-

LNG E-methane Hydrogen e-Ammonia

Methodology: Analysis of the clean fuels value chains

The efficiency and the carbon intensity have been estimated based on the following steps

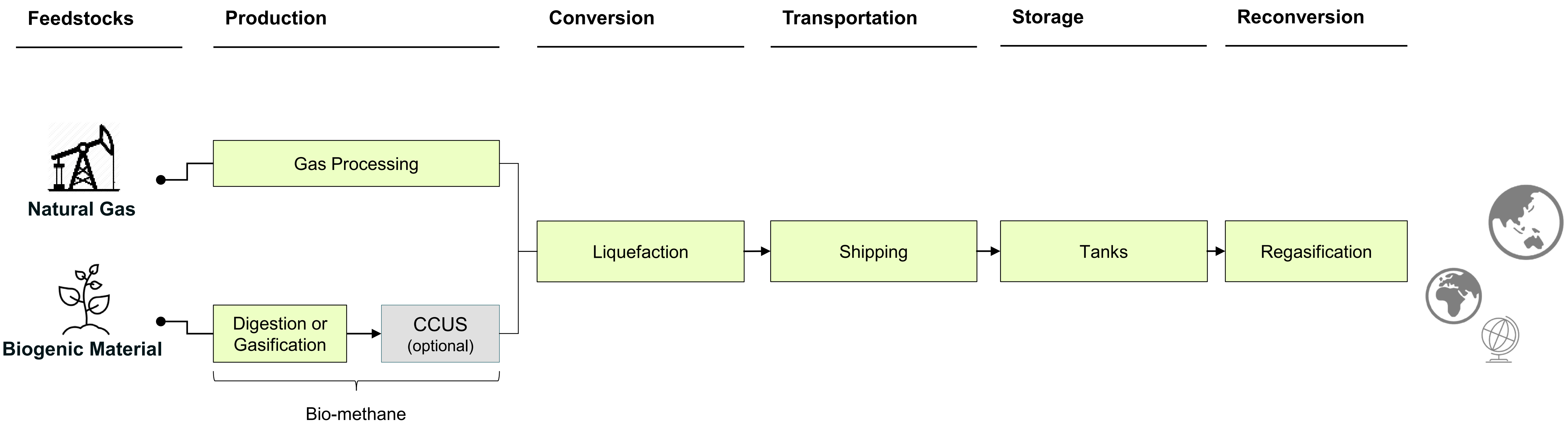


*Simplified view of the clean fuels value chains in focus, Guidehouse detail efficiency losses, final delivered energy content, embedded emissions, and LCOE between selected regions

Value chain of LNG and bio-LNG

Well established value chain with developed infrastructure

LNG



Technology overview of the value chain

LNG

TRL[1]

1 Initial Idea | 2 Application formulated | 3 Concept needs validation | 4 Early prototype | 5 Large prototype | 6 Pre-commercial demonstration | 7 Demonstration in operational environment | 8 Qualified for operation | 9 Commercial operation

Key take-aways

Natural gas is widely available with lower CO2 emissions than all other petroleum-derived fuels. Its infrastructure is well-established since years of operation, however, to meet growing global demand and due to geopolitical tensions – new routes need to be considered. LNG demand increased by 60% y-o-y in 2022 and is expected to remain high, following ongoing Russian-Ukrainian war. New available technologies, such as FLNG, allow to increase efficiency of LNG value chain, while gaining flexibility, as well as minimizing onshore construction work. Usage of LNG as bunkering fuel on ship is to take off, following the IMO regulations introduced in 2020.

Value Chain	Applicable Technologies	Maturity of the technology (TRL)	Foreseen technology evolution
Production	• MDEA, Benfield or SULFINOL, NRU	9	Purification of extracted gas using one of the available technologies with scrubbing process. Nitrogen rejection units (NRU) may be used to facilitate LNG storage, removing nitrogen from the gas and thus, reducing transportation volumes and increasing heating value of LNG.
Conversion	• Liquefaction (C3MR..)	9	Natural gas is liquefied at temperatures blow -160C with atmospheric pressure. Currently, this process can use up to 10-15% of feed gas to cool the gas to be exported. Advances in liquefaction technologies aim to increase efficiency, reducing energy consumption and operational costs. Using renewable energy in liquefaction process can help reduce emissions by 8%.[2] Cascade cooling process can be utilized, together with dual internally and externally structured tubes (Total and ADEME partnership), improving rate of heat exchange 15%, decreasing the need in number of LNG trains.
Transportation	• Pipelines with compressors • LNG vessel/tankers	8-9	The main developments in already well-established technologies for LNG shipment is bunkering technology, that will help to meet growing demand of clean fuel in marine industry.
Storage	• LNG terminal • FLNG	9 7	Floating liquefied natural gas (FLNG) system has emerged in recent years, capable to provide combined production, liquefaction, storage and transfer plant. PRICO process allows to achieve small train sizes (0,6 mtpa), that are easy to modularize.
Reconversion	• ORV, SCV • FSRU	9 7	Regasification is done through open rack vaporizer (ORV) or submerges combustion vaporizers (SCV). Floating storage and regasification units (FSRU) have been proven to be cost efficient and flexible solution, able to relocate and continue operations at a new location and are set to scale up.

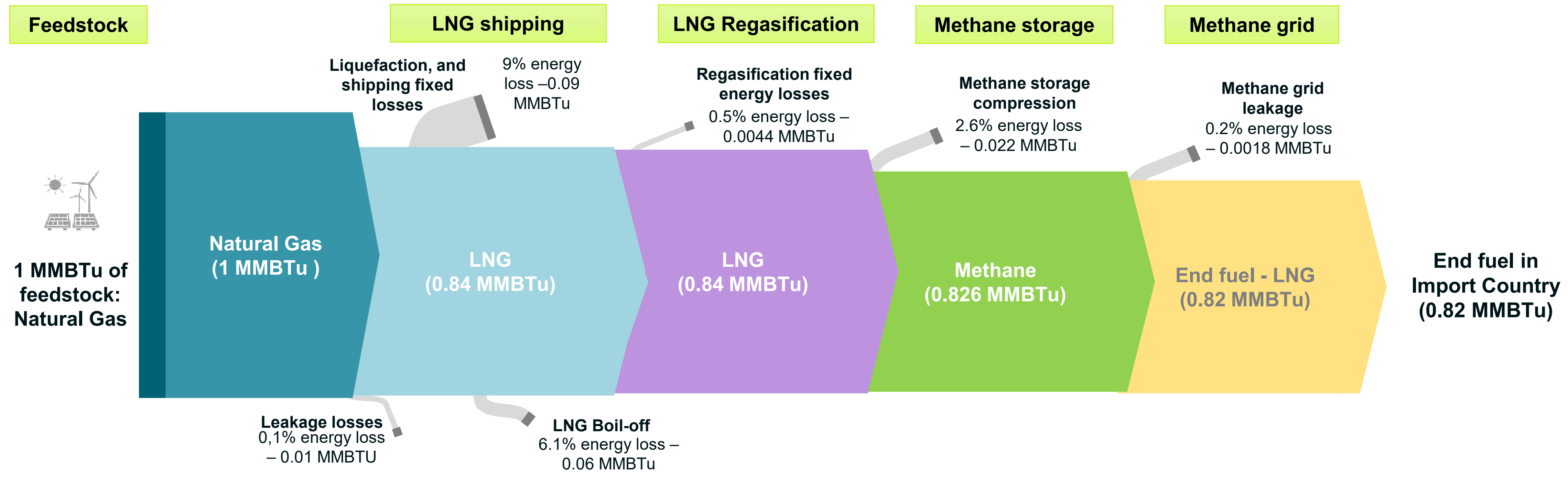
1. IEA ETP Clean Energy Technology Guide 2. Shell LNG Outlook 2024

Efficiency losses of the LNG conversion

LNG

18% of efficiency losses for the LNG alongside the value chain

2030 Value Chain of LNG (35,000km representative of Gulf Coast to Japan)



CO_2e emissions:	+10.04 $kgCO_2$/Mmbtu	+11.48 $kgCO_2$/Mmbtu	+0.65 $kgCO_2$/Mmbtu	+5.78 $kgCO_2$/Mmbtu	+1.42 $kgCO_2$/Mmbtu	Total 29.36 $kgCO_2$/Mmbtu

Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the $kgCO_2e$/MMBtu.

Guidehouse outwit complexity

Bio-LNG Production Processes

bio LNG

TRL

1 2 3 4 5 6 7 8 9

Research Development Deployment

Key take-aways

Bio-LNG is identical to LNG and both fuels can be used interchangeably, thus benefiting from existing LNG infrastructure, reducing logistics costs. There is growing interest in producing bio-LNG, following it’s renewable origins. Main feedstock used to produce biogas is crop residues, animal manure, organic fraction of MSW and wastewater sludge which is easily available across geographies and doesn’t create competition with food or land use. Following IMO regulation for GHG emissions reduction target for international shipping, bio-LNG is considered as an appealing alternative to fossil fuels, and thus, pushing its demand.

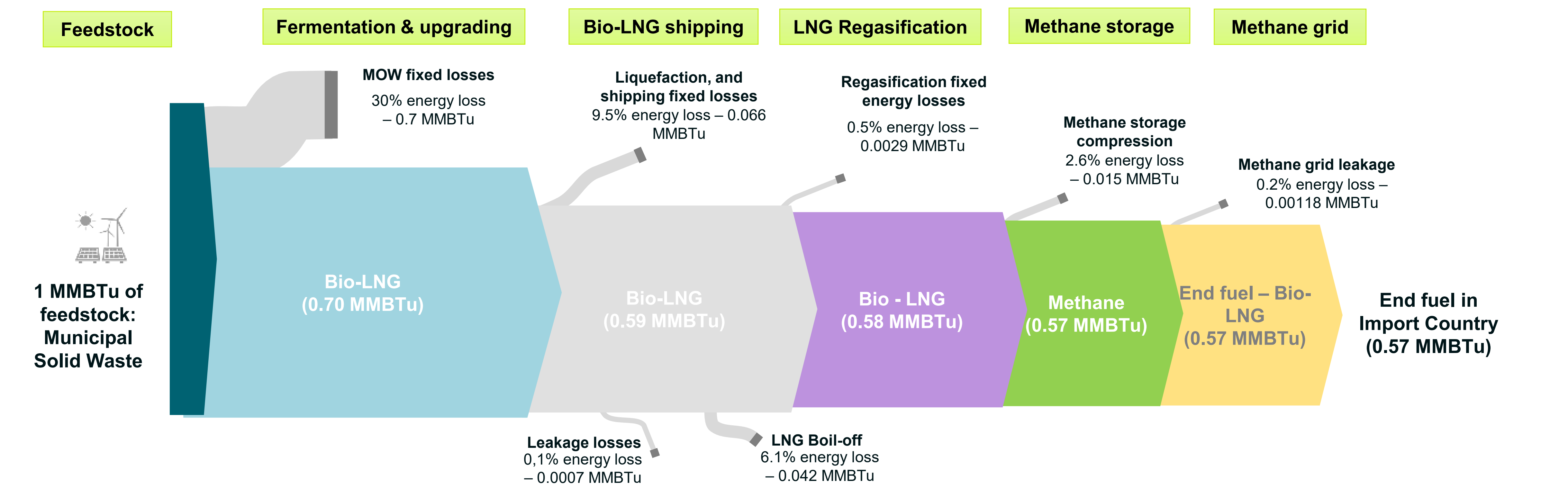
Value Chain	Applicable Technologies	Maturity of the technology (TRL)	Foreseen technology evolution
Production	• Anaerobic digestion • Biogas upgrading (with optional CCUS)	9 6-7	Main technology to produce biogas is anaerobic digestion, which is further “upgraded”, when any impurities are removed and biomethane is produced. Adding carbon capture to the process allows to receive biogenic CO2 feedstock that can be further reused for new gases production; however, technology is not yet at full maturity and needs to be developed further.
Conversion	• Liquefaction with RNG, TPSA and SMR	6-7	Biomethane liquefaction is achieved through, first, compression of the renewable natural gas (RNG) stream. Thereafter, a polishing step occurs with TPSA (temperature pressure swing absorption) and finally biomethane is liquefied, using Single Mixed Refrigerant (SMR) technology with temperatures ranging -150 to -155 C and with 2-4 bars. The off-gas produced during TPSA stage, undergoes a single stage membrane upgrading, before being reintegrated in the liquefaction system, that helps to minimize gas loss and enhance the efficiency of bio-LNG production.
Transportation	• Pipelines with compressors • LNG vessel/tankers	8-9	The main developments in already well-established technologies for LNG shipment is bunkering technology, that will help to meet growing demand of clean fuel in marine industry.
Storage	• LNG terminal • FLNG	9 7	Floating liquefied natural gas (FLNG) system has emerged in recent years, capable to provide combined production, liquefaction, storage and transfer plant. PRICO process allows to achieve small train sizes (0,6 mtpa), that are easy to modularize.
Reconversion	• ORV, SCV • FSRU	9 7	Regasification is done through open rack vaporizer (ORV) or submerges combustion vaporizers (SCV). Floating storage and regasification units (FSRU) have been proven to be cost efficient and flexible solution, able to relocate and continue operations at a new location and are set to scale up.

Efficiency losses of the bio-LNG conversion

Bio LNG

43% of efficiency losses for the LNG along the value chain

2030 Value Chain of BIo-LNG (35,000km representative of Gulf Coast to Japan)



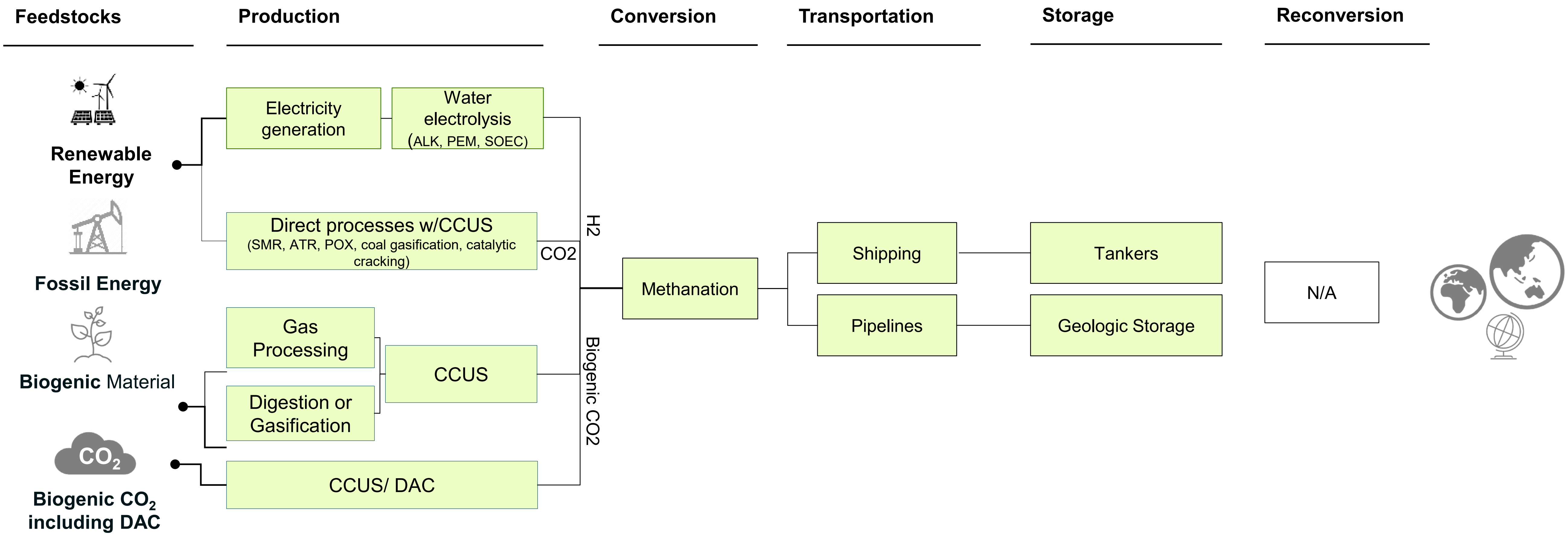
CO_2e emissions:	+ 7.91 kgCO_2/Mmbtu	+11.84 kgCO_2/Mmbtu	+0.65 kgCO_2/Mmbtu	N/A	+1.37 kgCO_2/Mmbtu	Total 21.77 kgCO_2/Mmbtu

Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the kgCO_2e/MMBtu.

Value chain of e-methane

E-methane

More complex value chain with various technologies applied for the production stage of e-methane



Technology overview of the value chain

E-methane

TRL

1 2 3 4 5 6 7 8 9

Research Development Deployment

Key take-aways

E-methane offers easier logistics comparing with hydrogen, using same logistics infrastructure as natural gas and LNG. E-methane can help to decarbonize certain industries, where options are currently limited, such as feedstock in chemical industry or fuel in marine transport. Main cost drivers for e-methane production are the costs for RE, along with the cost of the electrolysers needed for h2 production. Furthermore, a biogenic CO2 is essential for producing e-methane, but currently, feedstock availability is not at the required scale, which may also drive the cost. Direct Air Capture (DAC) is even more expensive.

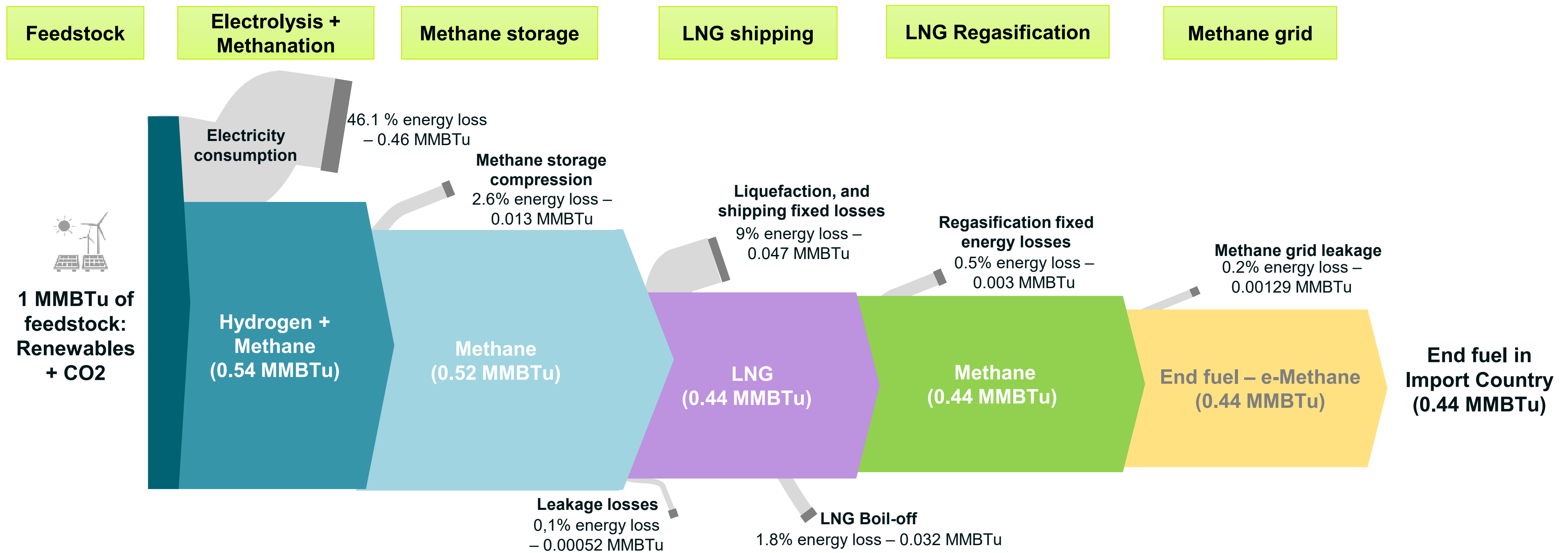
Value Chain	Applicable Technologies	Maturity of the technology (TRL)	Foreseen technology evolution
Production	• DAC • CCUS • Hydrogen Production	6 6 8-9	At the moment, deriving CO2 from the atmosphere by using DAC technology is quite expensive, but with foreseen scaling up the projects – price is set to lower down. Following the RED regulation for the origins of CO2 in e-fuel – the need for the rapid development of technology is there. Capturing of CO2 emissions produced by biogenic source is another way to receive feedstock necessary for e-methane production. Based on the projects that are currently in early stages of deployment – capture can reach 60 MtCO2/yr. Following the Net Zero scenario, the need for biogenic CO2 will be 185 MtCO2/yr by 2030.
Conversion	• Biological CO2 & Chemical methanation • Liquefactions	6-7 9	Biological methanation is conducted at moderate temperature and pressure without chemical catalysts, while chemical methanation is using nickel as the catalyst. The key limitation is in low h2 to liquid mass transfer, requiring bigger reactor dimensions. Heavy reliance on availability of DAC technology or biogenic CO2 as a feedstock is the main challenge but with newly announced projects there is a potential to scale up to 1 Mt CO2/year.
Transportation	• Pipelines • Shipping	9	Using already available infrastructure for natural gas and LNG, such as pipes, ships and trucks.
Storage	• Geologic storage • Tankers and vessels	8-9 9	Depending on the form in which it is stored: gaseous or liquid, e-methane is fully interchangeable with natural gas or LNG, thus, can use available storage infrastructure.
Reconversion	• Regasification: ORV, SCV • FSRU	9 7	In the regasification terminal, the liquid methane (-160°C) is returned to its gaseous state by the simple operation of heating and it is then injected into the gas pipeline networks.

Efficiency losses of e-Methane conversion

E-methane

56% of efficiency losses for e-methane due to energy intensive conversion steps mostly at production

2030 Value Chain of e-Methane (35,000km, representative of Gulf Coast to Japan)

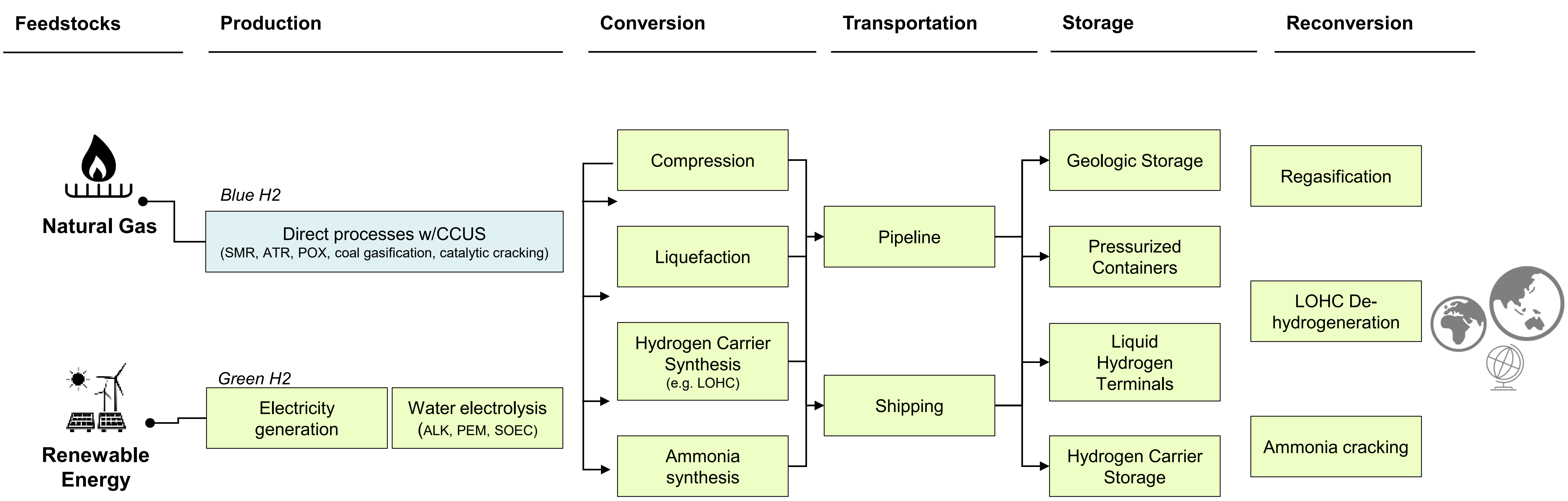


CO_2e emissions:	+14.15 kgCO_2/MMbtu	+ 0 kgCO_2/MMbtu	+ 11.46 kgCO_2/MMbtu	+0.65 kgCO_2/MMbtu	+ 1.36 kgCO_2/Mmbtu	Total 27.62 kgCO_2/Mmbtu

Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the kgCO_2e/MMBtu.

Value chain of Hydrogen (Green and Blue)

Production technologies vary depending on the type of hydrogen that has to be derived



Technology overview of the value chain

Hydrogen

TRL

1 2 3 4 5 6 7 8 9

Research Development Deployment

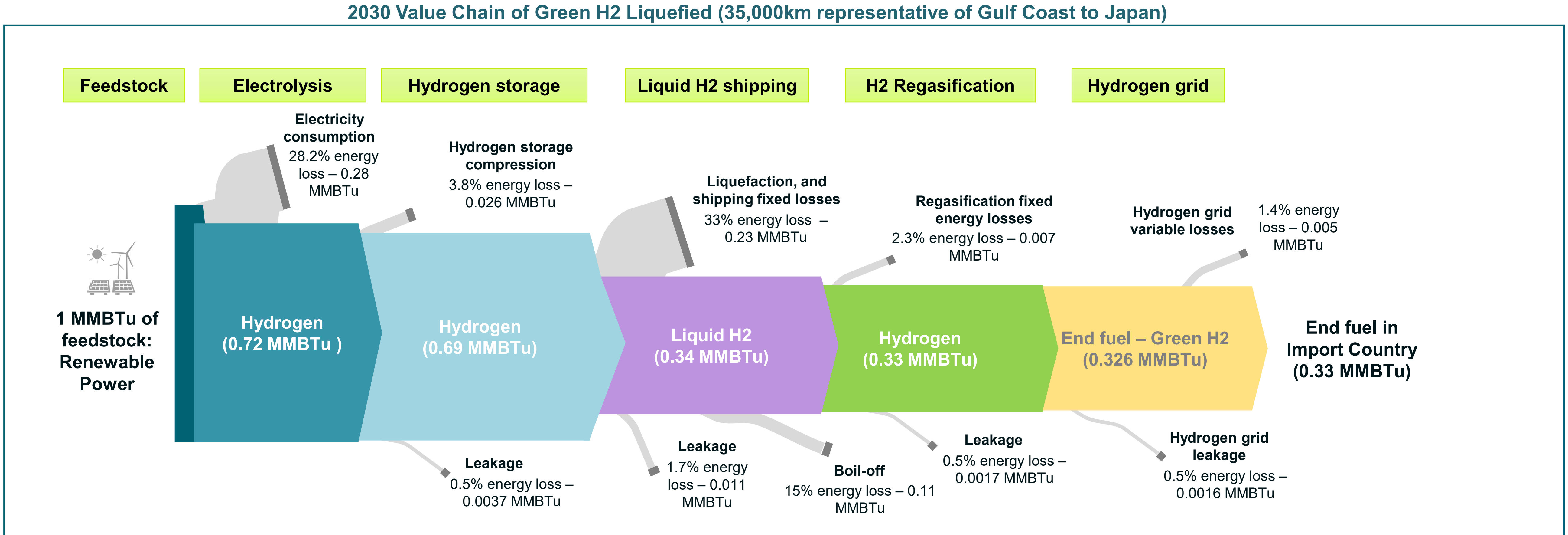
Key take-aways

Overall, the value chain of Blue and Green hydrogen is viewed as mature, with expected improvements in production technologies, which will help to increase efficiency of the fuel and significantly cut the costs. For production of green hydrogen, water electrolysis are currently predominant with ALK technology, however by 2030, PEM will overtake the dominance, finally, moving towards SOEC, which will reach its maturity by 2050, offering high-cost reduction potential and higher efficiencies. For production of blue hydrogen, CCUS technology is expected to reach its commercial scale by the end of the decade. Regarding transportation and storage of hydrogen, available gas infrastructure (pipes and depleted gas fields) is planned to be widely repurposed, as well as new infrastructure – built out.

Value Chain	Applicable Technologies	Maturity of the technology (TRL)	Foreseen technology evolution
Production	• **Blue H2**: ATR, SMR, POX • **Blue H2**: + CCUS • **Green H2:** ALK, PEM • **Green H2:** SOEC	7-8 5-6 7 6	SMR and ATR production technology are at full commercial maturity, CCUS applied to hydrogen production is expected to reach commercial scale of multi-MtCO_2 capture levels by the end of the decade. Currently, Alkaline electrolyser is the most mature and least costly technology, however, PEM is on track of taking the lead in the coming years with numerous projects being announced.
Conversion	• Compressors, • Liquefaction, LOHC • Haber-Bosch	7 7 9	As H2 has lower molar mass and higher volumetric flow than natural gas, higher compression efforts are required, comparing with NG. Research for compact solution is undergoing for higher efficiencies. Even though liquefaction is considered as established technology, it still needs to be scaled up to reduce costs and improve efficiency. Concerning Haber-Bosch technology, which is used for ammonia conversion – it is well established process, with key challenge to integrate in the process RE sources.
Transportation	• Repurposed NG pipelines • Hydrogen pipelines • Liquefied hydrogen tanker	8 9 6-7	Repurposing existing natural gas pipelines to carry H2 reduce new material needs, lowering costs and benefitting the environment. H2 pipelines are used to connect regions with high demand. Currently infrastructure being developed. Hydrogen can be also transported in a liquefied form by ship tankers. Scaling up is required for growing h2 trading.
Storage	• Pressure vessel • Geologic storage • Tankers	9 6-7 9	Pressure vessels are used in chemical industry and can be easily reused for H2 storage, using pressure of 180-250 bar, they can care up to 380 kg onboard. In the future, more light-weighted vessels will be used, that can carry 560-900kg of H2, increasing hauling efficiency. Cryogenic tanks are lighter than pressure vessel, but liquefaction is more energy intensive process.
Reconversion	• Ammonia cracking • LOHC dehydrogenation	3-6 6-7	If hydrogen been transported in the form of ammonia - ammonia cracking is not as mature as ammonia synthesis, currently on a stage of development, requiring identification of cost-effective technology for large-scale applications. LOHC dehydrogenation requires 35-40% of energy content of the stored hydrogen due to high temperature required.

Efficiency losses of Green H2 liquefied

67% of efficiency loss for green LH2 due to the liquefaction at -253C



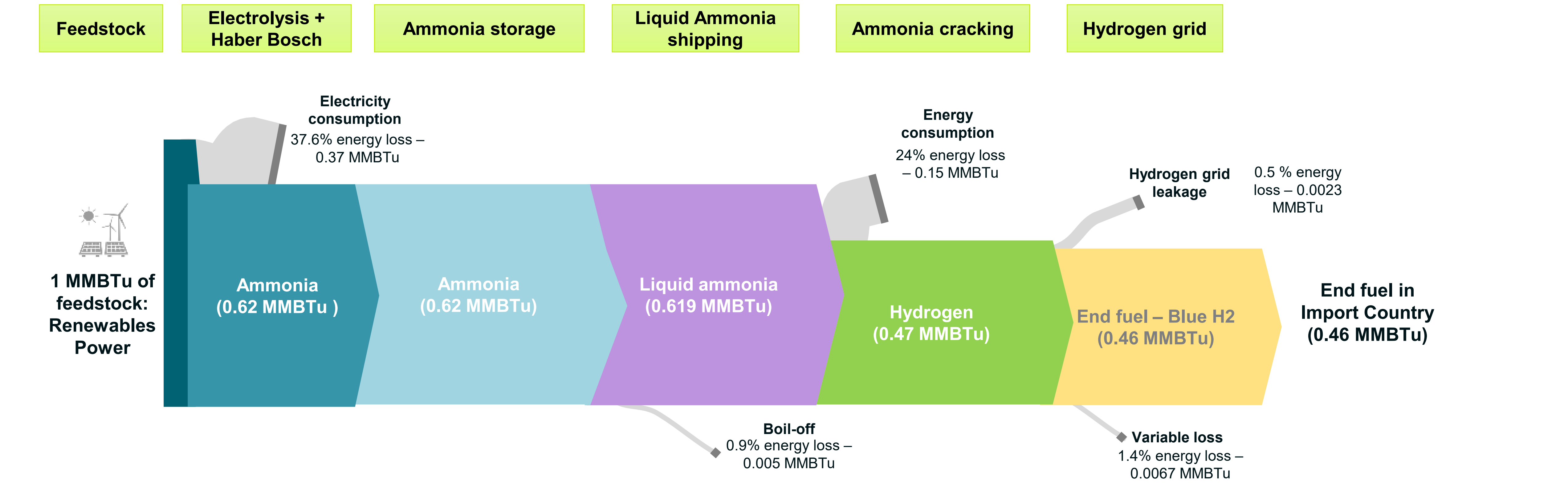
CO_2e emissions: + 10.6 $kgCO_2$/Mmbtu | +3.17 $kgCO_2$/Mmbtu | +28.56 $kgCO_2$/Mmbtu | + 3.5 $kgCO_2$/Mmbtu | + 1.9 $kgCO_2$/Mmbtu | **Total 47.87 $kgCO_2$/Mmbtu**

Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the $kgCO_2e$/MMBtu.

Efficiency losses of Green H2 as NH3 reconverted

54% of efficiency loss for green H2 with conversion to NH3 and reconversion to H2

2030 Value Chain of Green H2 as NH3 reconverted (35,000km representative of Gulf Coast to Japan)



CO_2e emissions:	+10.75 $kgCO_2$/Mmbtu	+0 $kgCO_2$/Mmbtu	+9.6 $kgCO_2$/Mmbtu	+ 31.26 $kgCO_2$/Mmbtu*	+1.9 $kgCO_2$/Mmbtu	Total 53.62 $kgCO_2$/Mmbtu

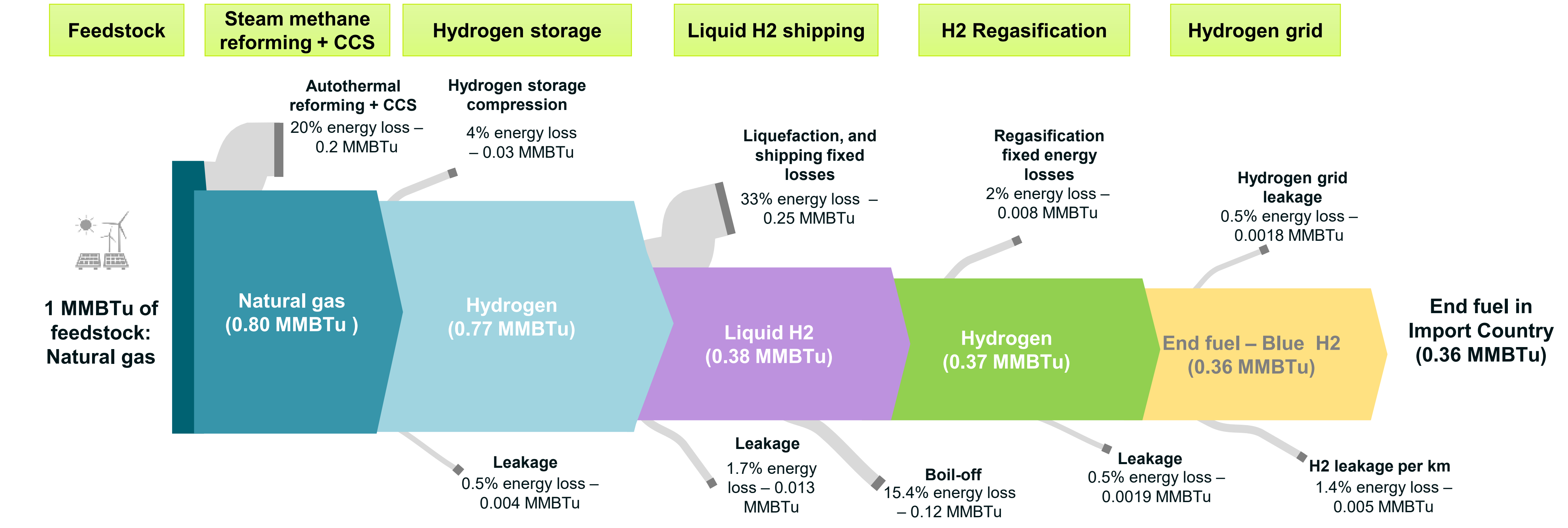
Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the $kgCO_2e$/MMBtu.

*Carbon intensity of Japan's grid is 11 times greater than one of Europe, driving higher CO2 emissions of ammonia cracking step (31.25 kgCO2/Mmbtu for Japan vs 2.69 kgCO2/Mmbtu for Europe)

Efficiency losses of Blue H2 liquefied

64% of efficiency loss for blue H2 due to the liquefaction at -253C

2030 Value Chain of Blue H2 Liquefied (35,000km representative of Gulf Coast to Japan)



CO_2e emissions:	+20.56 $kgCO_2$/Mmbtu	+3.17 $kgCO_2$/Mmbtu	+28.56 $kgCO_2$/Mmbtu	+3.52 $kgCO_2$/Mmbtu	+ 1.98 $kgCO_2$/Mmbtu	Total 57.82 $kgCO_2$/Mmbtu

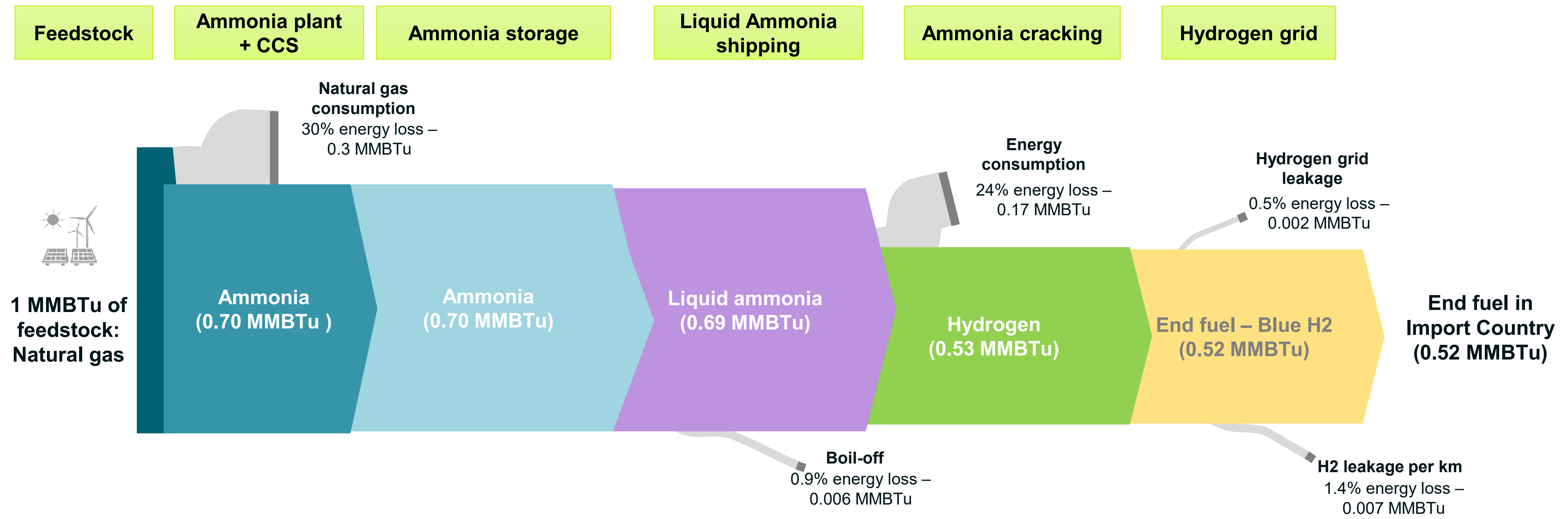
Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the $kgCO_2e$/MMBtu.

Efficiency losses of Blue H2 as NH3 reconverted

Green Hydrogen

48% of efficiency losses for blue H2 with conversion to NH3 and reconversion to H2

2030 Value Chain of Blue H2 as NH3 reconverted (35,000km representative of Gulf Coast to Japan via Panama Canal)



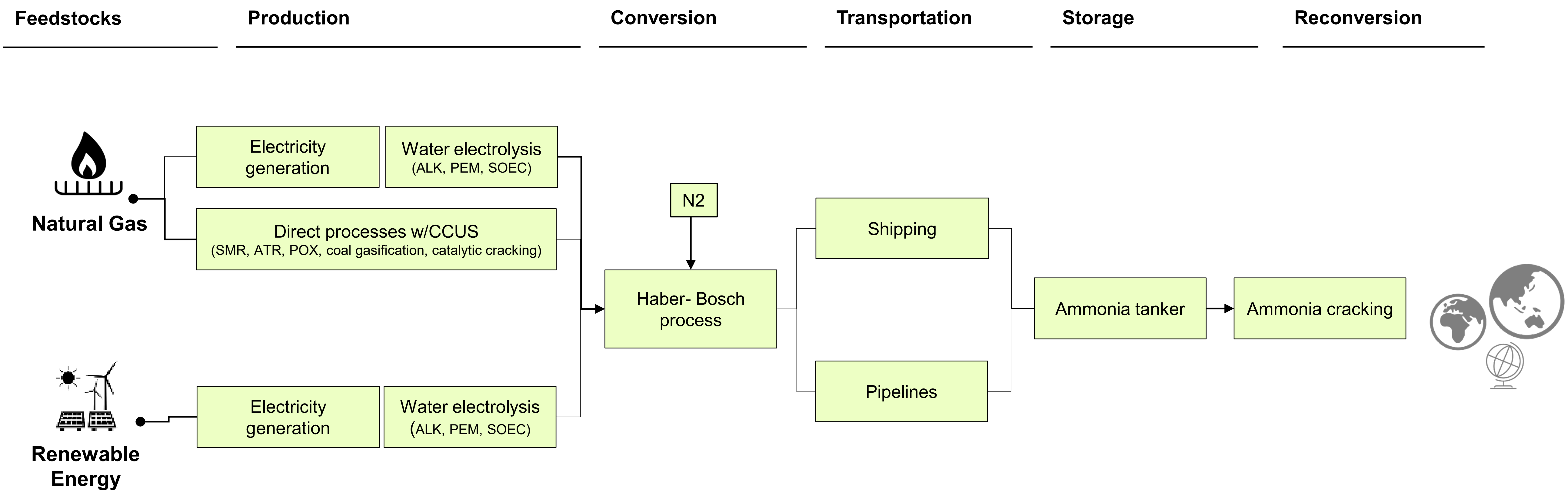
CO_2e emissions:	+ 27.8 $kgCO_2$/Mmbtu	+0 $kgCO_2$/Mmbtu	+9.6 $kgCO_2$/Mmbtu	+31.28 $kgCO_2$/Mmbtu	+1.98 $kgCO_2$/Mmbtu	Total 70.68 $kgCO_2$/Mmbtu

Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the $kgCO_2e$/MMBtu.

Value chain of Ammonia (Green and Blue)

e-Ammonia

Identical process of production as for hydrogen with additional Haber-Bosch process for N2 injection



Technology overview of the value chain

e-Ammonia

TRL

1 2 3 4 5 6 7 8 9

Research Development Deployment

Key take-aways

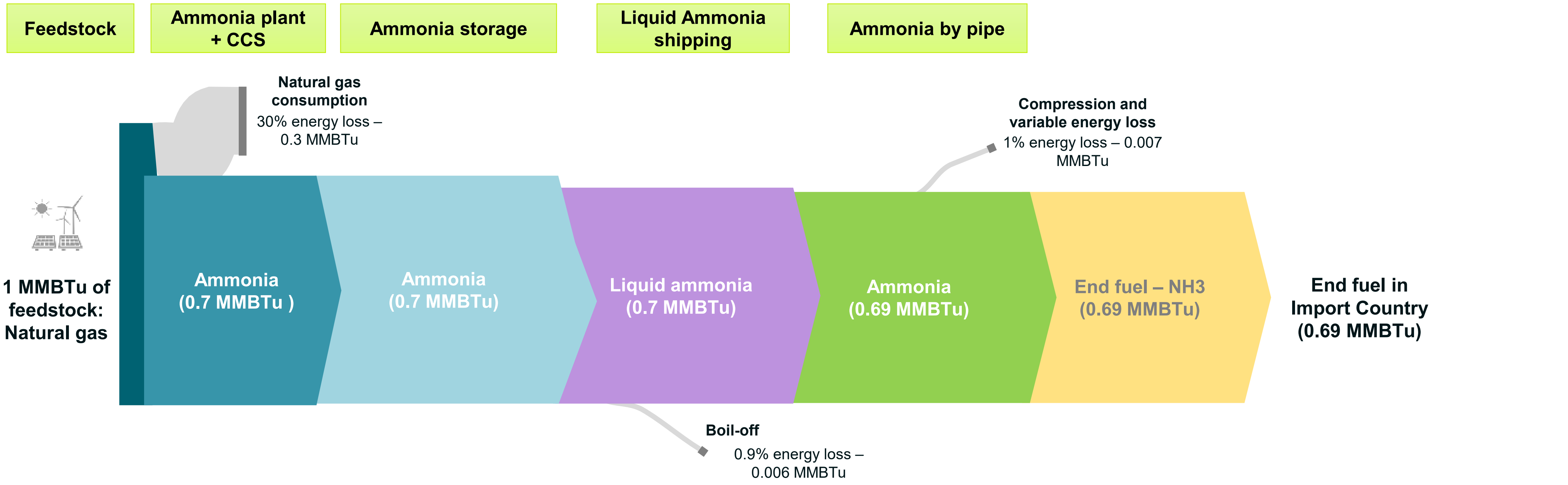
Ammonia is viewed as most efficient way to transport and store hydrogen with available mature production technology. The challenge is lying in reconversion of molecule into H2 using ammonia cracking technology - that is currently very energy consuming process. Numerous ammonia to hydrogen pilot projects have been lunched worldwide to scale and optimize current process and research the ways of using more efficient catalysts for its decomposition. In addition, purification of hydrogen after ammonia cracking needs to become less costly.

Value Chain	Applicable Technologies	Maturity of the technology (TRL)	Foreseen technology evolution
Production	• Hydrogen production	8-9	Previously described, hydrogen production using well established technologies, is expected to scale up in the coming years with improved efficiencies and lower costs.
Conversion	• Haber-Bosch	9	Haber-Bosch technology for ammonia conversion is well established process, mainly utilized to produce grey ammonia, however shifting towards carbon neutral production, where green h2 is used is overseen. Growing availability of RE and lowering costs for green H2 production will consequently reduce cost of ammonia production. Research is being conducted for improving efficiency of the process by utilizing more efficient catalysts, reducing necessary temperature and pressure.
Transportation	• Vessels • Pipelines	9	Ammonia is shipped in fully refrigerated, non-pressurised vessels, often designed to carry liquefied petroleum gas (LPG). Research is currently looking at use of ammonia as fuel by ships, with separate cargo tanks, able to carry ammonia and LPG simultaneously, increasing flexibility. Pipelines are cheaper option for transporting ammonia, projected to transport 15Mt/year of green ammonia by 2030 and 71 Mt/ year by 2040.
Storage	• Ammonia tanker	9	Ammonia is easier to store than H2, with already existing infrastructure available. Scaling up is foreseen at trade ports as ammonia might be used as fuel in shipping sector (75% of energy consumption by shipping sector by 2050) and RePowerEU plan (import 4Mtpa -22Mtpa by 2030).
Reconversion	• Ammonia cracking	3-6	Ammonia cracking is using inexpensive, already commercially available materials, such as iron. However, the energy consumption during the process that is using high temperatures (600-900 C) is about 30% of the energy content of ammonia. Low temperature cracking (450 C) uses less energy but still on low maturity levels. In addition, the technology for separation and purification of h2 needs to become less costly. Numerous pilot projects have been launched worldwide with the goal to address challenges on efficiencies, costs, purity and scale.

Efficiency losses of Blue NH3

31% of efficiency losses of Blue H2 used as direct NH3

2030 Value Chain of Blue H2 used as NH3 (35,000km representative of Gulf Coast to Japan)



CO_2e emissions:	+ 27.8 $kgCO_2$/Mmbtu	+ 0 $kgCO_2$/Mmbtu	+ 9.6 $kgCO_2$/Mmbtu	+1.14 $kgCO_2$/Mmbtu	Total: 38.55 $kgCO_2$/Mmbtu

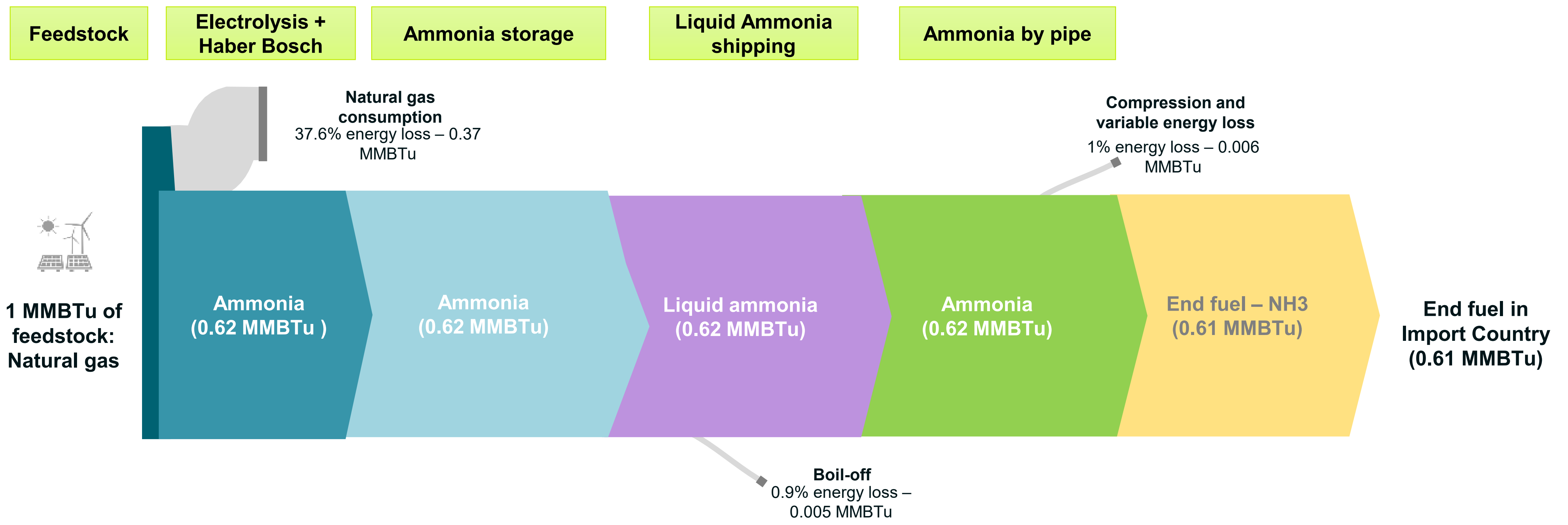
Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the $kgCO_2e$/MMBtu.

Efficiency losses of Green NH3

e-Ammonia

39% of efficiency losses of Blue H2 used as direct NH3

2030 Value Chain of Green H2 used as NH3 (35,000km representative of Gulf Coast to Japan)



CO_2e emissions:	+10.7 $kgCO_2$/Mmbtu	+0 $kgCO_2$/Mmbtu	+9.6 $kgCO_2$/Mmbtu	+0.6 $kgCO_2$/Mmbtu	Total 20.97 $kgCO_2$/Mmbtu

Values presented on a per MMBtu of feedstock energy, not final delivered fuel. Since the fuel is not delivered until the last step, the total CO2 must be divided by the total value chain efficiency to achieve the $kgCO_2e$/MMBtu.

Feedstock and primary energy

-Feedstock potential-

Global Feedstock Review – Biogenic CO2

Biogenic CO2

US is considering capturing CO2 locally and exporting it to e-fuel production countries (such as Middle East or Africa) to stay compliant with the requirement of usage of certified unavoidable CO2

US Golf Coast

High potential for production of the feedstock due to dense industrial cluster in the region

USA has dedicated policies and initiatives for production of biogenic CO2:

- Renewable Fuel Standard (RFS) that mandates renewable fuels with gasoline and encourages production of biogas and other biofuels, that generate biogenic CO2 as a byproduct
- 45Q Tax Credit provides financial incentives for CCS projects, making biogenic CO2 capture and utilization economically viable.
- IRA and BIL further enchasing 45Q Tax credit by providing increased credit value and extended timeline of the debut of project construction. Additional grants are now available under BIL.

NORTH AFRICA

Some carbon pricing mechanisms can motivate development of biogenic CO2 capture

- As of today, no projects nor national support are planned for biogenic CO2 capture.
- Expansion of biomass energy incentives, promoting generation of biogas and biomethane as a substitute to fossil fuels could generate additional biogenic CO2 feedstock that can be captured and further reused.

MIDDLE EAST

The region is well positioned to become a leader in CCUS, following it's commitment to decarbonization

- Active player in Clean Air Taskforce, working on national policies and incentives for carbon capture, storage and transportation. Most of the initiatives are dedicated to decarbonization of Oil & Gas sector.
- Some countries, such as Qatar and UAE has introduced multiple initiatives to reduce GHG emissions, including deployment of CCUS.
- . No specific regulations related to biogenic CO2

AUSTRALIA

Development of certification schemes and associated legislative frameworks for biogenic CO2

- Renewable Energy Target (RET), promoting increase in use of renewable energy sources , such as biomass and bioenergy, thus generating biogenic CO2 that can be further captured.
- CCS Flagship program, providing funding to demonstration projects dedicated to carbon capture and storage.
- AUD 50 million CCUS Fund providing support for pilot and pre-commercial projects.

Global Feedstock Review – Biogenic CO2

Biogenic CO2

The global roll-out of CCUS is expected in the coming years, however DAC technology remains limited, representing only 2% of all planned projects

Key take-aways and trends

- Following the rules set by EU (RefuelEU) and US (RFS) the origins of CO2 for e-fuel will be strictly regulated, meaning reliance on DAC technology will increase considerably.
- In this study CO2 emissions captured by DAC technology are considered to be 100% biogenic.
- Carbon capture, utilization, and sequestration (CCUS) has increasingly been recognized as an essential component of decarbonization strategies. However, existing capacity and announced projects are far less than what is needed for the rapid global deployment, necessary for NZ goals achievement.
- DAC technology should see rising deployments but will likely remain less than 2% of the global CCUS market (11 Mtpa) by 2030. [1]
- Starting from 2030 to 2050, DAC technology should increase it's growth pace and start being competitive.

Feedstock Trends and Availability outlook

- Currently, USA drives the development of DAC, backed up by national support in form of increasing tax credits for CO2 capture technologies and piloting projects for its capture.
- DAC plants are operating at the small scale but with plans to grow.
- Overall, plans for at least 130 DAC facilities are now at various stages of development. Some of the largest projects under development are in America:
    - Stratos, South Texas DAC hub
    - HIF eFuels Matagorda (Texas and/or Chile)
    - Cypress DAC hub in Louisiana

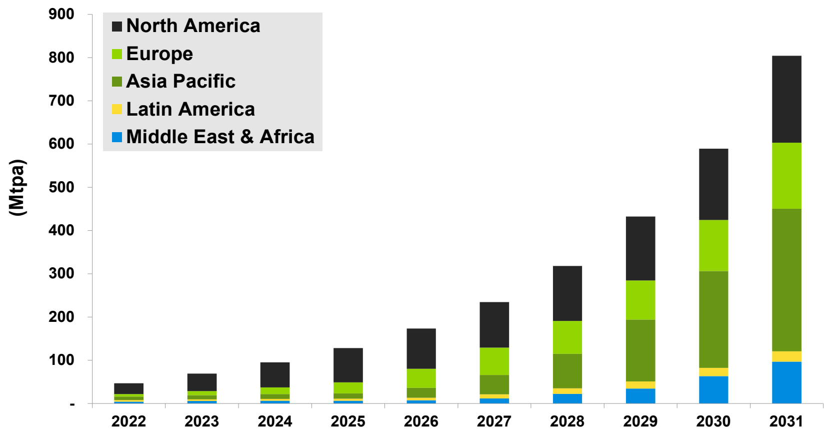
And Europe:

- Norway - the Kollsnes DAC project
- Iceland - the Mammoth project.

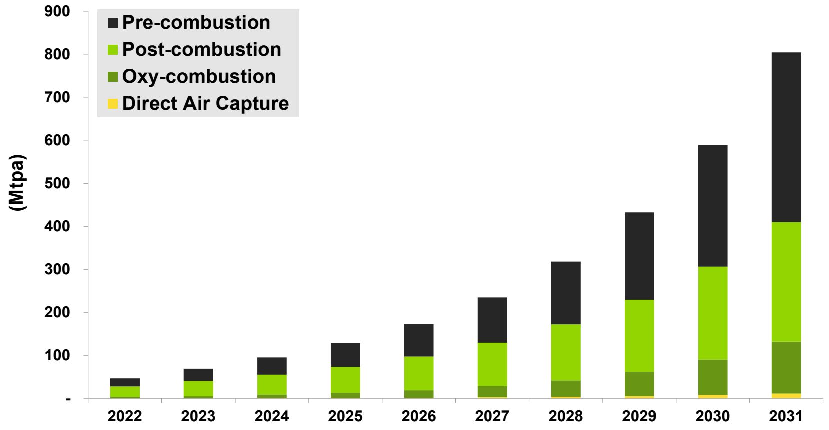
Two megatonne-scale projects have also been announced in Kenya and the UAE, but are still at early stage.

1. Guidehouse Insights, Carbon Capture, Utilization and Sequestration, 2022

CCUS Capacity by Region, 2022-2031



CCUS Capacity by technology, 2022-2031



Guidehouse Insights, Carbon Capture, Utilization and Sequestration

Global Feedstock Review – Biogenic CO2

Biogenic CO2

US Gulf Coast is the leader in high-capacity carbon capture infrastructure being rolled out

- **USA (Gulf Coast)**
- Approximately 2000km of pure CO_2 pipeline act as an enabler for early large-scale biogenic CO_2 capture at ethanol plants in North-West Texas.
- There are 3 ethanol plants, 16 biomass power plants and 111 waste plant with a total estimation of over 20 Mt CO2/year largely biogenic + DAC projects announced in Gulf Coast to be capturing more than 6 Mt CO2/year.
- Depending on the regions where the planned projects are located, the origin of biogenic CO2 will mainly come from the production of ethanol (Midwest), cement plants (Texas and Midwest) as well as the production of pulp and paper (Gulf Coast).

NORTH AFRICA
- Although, it is unclear what the potential for biogenic CO2 will be in North Africa, the region has a strong pulp and paper industry and multiple ethanol plants that emit biogenic CO2 and could be captured in the future.
- Due to the region's low cost and highly abundant renewable electricity, it could also be an ideal site for DAC projects in the future, although no projects are planned today.

MIDDLE EAST
- Extensive storage capacity and clean energy resources make the region well placed to demonstrate and scale up direct air capture in particular.
- Few projects under development, in particular in UAE (1 project) and Qatar (3 projects) with ongoing contraction, able to capture up to 1 Mt CO2/year. Saudi Arabia has started testing DAC technology in 2024.

AUSTRALIA
- Australia has 25 biomass plants, 14 ethanol plants and 3 pulp and paper plants, being able to provide feedstock of biogenic CO2.
- AspiraDAC has started commissioning of DAC in 2022 and is set to deploy 180 machines by 2027, able to capture 500t CO2/year. Another project in developing stage will be able to capture 310t CO2/year.

DAC projects under construction in considered geographies

Geography	Country	DAC Project Name	CO2 capture capacity,Mtpa	Project start
USA (Gulf Coast)		Stratos - Occidental	1	2025
		Gulf Coast Sequestration Hub	2.7	2030
		Project Cypress DAC hub	1	N/A Year announced 2023
		HIF Haru Oni	1	2025
		Occidental Kleberg DAC	1	2025
North Africa		N/A		
Middle East	Saudi Arabia	Aramco Siemens DAC Pilot	N/A	2024
	UAE	Fujairah DAC	N/A	2023
	UAE	Adnoc Occidental DAC	1	N/A Year announced 2023
	Oman	Khazaen Economic City	N/A	N/A Year announced 2021
	Oman	Hajar Mountains	N/A	2024
Australia	Australia	Aspira DAC	N/A	2022

Guidehouse Insights database

Feedstock potential by region

The main prerequisite for development of infrastructure is land and electricity availability

Region	Availability	Drivers	Challenges
US Gulf Coast	5 DAC projects	• Great governmental support with various fundings and incentives. • Availability of biogenic CO2 deposits, that are located in proximity of h2 hubs.	• The availability of sufficient quantities of feedstock and price of technology remains the main challenge.
North Africa	0 projects	• Important renewables potential. • Geographical proximity with Europe. • Geographic proximity with Europe and possibility to import the feedstock for future clean-fuels production.	• Lack of demand for the feedstock. • Lack of regulatory requirements and economic support. • No projects are planned as of today.
Middle East	5 projects	• High penetration of Oil & Gas companies willing to reduce their emissions, possessing vast economic resources. • High renewables potential.	• Lack of demand for the feedstock. • Still high reliance on fossil fuels and lack of motivation to roll-out the required infrastructure in necessary size.
Australia	1 project	• Governmental support with certification schemes. • High concentration of industries that can provide biogenic CO2 feedstock if captured.	• The capturing technology is still on stage of development and testing. • Amounts of biogenic CO2 feedstock is still not sufficient for scaled-up production of e-fuels.

Global Feedstock Review – RE Electricity

Electricity

All of exporting countries have set national targets to increase RE generation in the coming years

US Golf Coast

Strong commitment for renewable electricity production driven by ambitious policy regulation

USA has introduced IRA and BIL which provides financing for clean initiatives via tax credits. $30B dedicated specifically for clean energy transition, allowing to significantly reduce upfront capital costs for solar and wind installations.

NORTH AFRICA

Solar and wind power are expanding and getting cheaper following ratification of Paris agreement

Most North African countries have set ambitious RE targets with capacity expansion by 2040. With proposed strategies for clean hydrogen development in the continent, the expansion of renewables accelerates, potentially reaching 66 GW from solar PV and wind by 2040.

AUSTRALIA

Very recent integration of National Energy Transformation plan requiring rapid market reforms

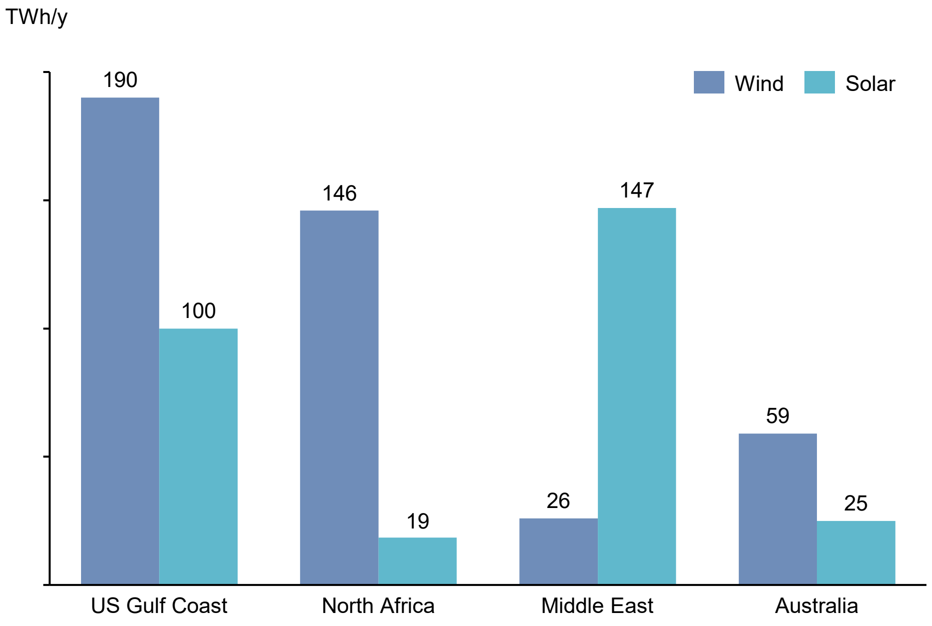
Australia has passed the Climate Change Act and set a strategy to position itself as global leader in Hydrogen export by 2030, requiring rapid roll-out of new RE generating capacities. Target of 82% share of RE in electricity production by 2030.

MIDDLE EAST

Oil & Gas heavy countries are reconsidering energy mix to meet growing demand

Middle East countries, with some of the highest solar irradiance levels in the world, introduced national climate targets as well. UAE outlined its 2050 energy mix target, under which renewables are to account for 44% of power production. Saudi Arabia is committed to achieving 50% of energy production from renewables by 2030. Qatar target is 20%.

Renewable Electricity Generation by Region, 2030 view



Source: IEA Global Energy Outlook 2023
IRENA, Electricity Generation and Capacity by Region

Global Feedstock Review – RE Electricity

Electricity

Acceleration of renewable energy deployment is being coupled with increasing electrification of economic activity

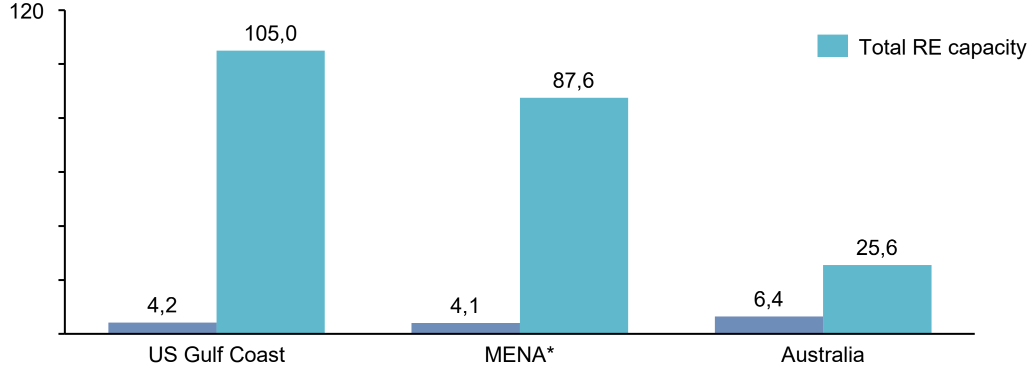
Key take-aways and trends

- Renewable energy capacities are rapidly expanding globally with United States leading the growth among analysed countries.
- In all analysed countries surplus of RE feedstock is previewed, making it possible to participate in export market.
- Surplus of renewable energy generated can be transformed in hydrogen for storage purposes or production of alternative fuels - reducing intermittency of the source.
- All exporter countries has announced projects focused on adding renewable energy capacities to produce clean hydrogen. Targets vary from geography to geography but overall, generating capacities are significantly overpassing the demand.

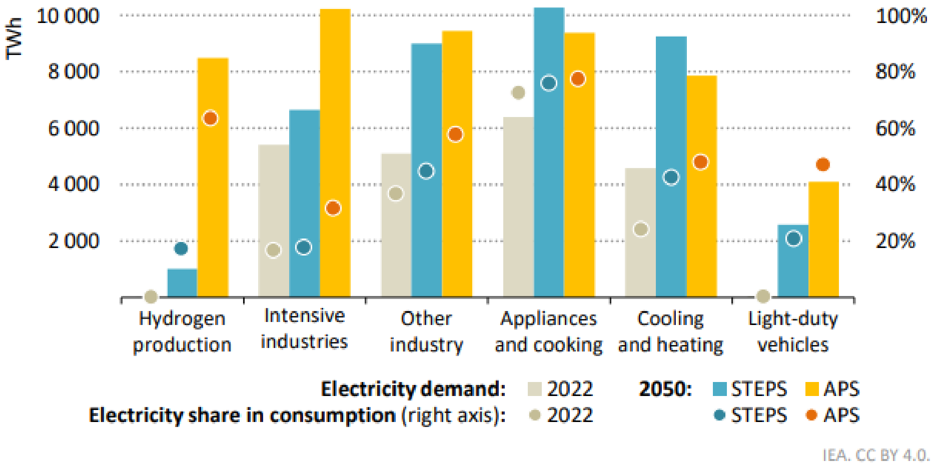
Feedstock Trends and Availability outlook

- The biggest consumers of electricity today are the buildings and industry sectors. This demand is projected to grow, especially driven by emerging markets and developing economies, as policies being set to electrify intensive industries. Hydrogen production drives substantial demand in clean electricity as well.[1]
- In developing countries, demand for clean electricity is pushed mostly by power sector, while in developed economies future focus is set on electrification of transportation sector and intensive industries.
- All considered geographies has set a target to become exporters of clean fuels, thus feedstock dedicated purely for their production will be planned and should not present competitive problem for other use cases.

Planned H2 production capacities vs total RE electric capacity previewed by 2030, GW



Global Electricity demand and share of electricity in selected applications, 2022 and 2050 view (IEA)



1. IEA Global energy outlook 2023

* MENA – Middle East and North Africa

1.STEPS – Stated Policies Scenario - 3,327 TWh/year in 2050.

2. APS – Announced pledges scenario - 4.384 TWh/year in 2050.

Global Feedstock Review – RE Electricity

Electricity

While available quantity of RE is much higher in Europe, it’s cost is lower in considered geographies

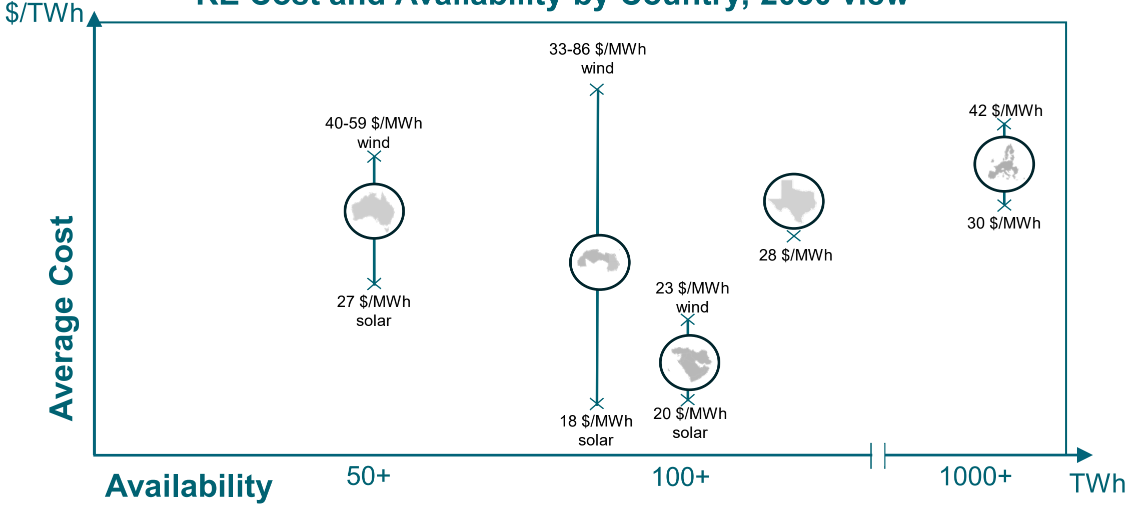
USA (Gulf Coast)
- High availability expected towards 2030-2050 particularly in the Gulf Region
- Available infrastructure well established and is expected to grow considerably, following governmental support.
- Currently higher electricity costs compared to the other regions but still cheaper than the electricity produced in Europe.

NORTH AFRICA
- Potential for renewable energy generation is vast due to geographic positioning of considered countries.
- Available infrastructure for RE production is currently very limited but projected to rapidly roll-out, following governmental and public support, as well as strategic partnerships, especially with Europe.
- Electricity costs are one of the cheapest among considered regions

MIDDLE EAST
- Highest potential for Renewable energy generation from all considered countries, especially driven by solar PV generations
- Similarly to North Africa, current available infrastructure is limited but projected to roll out following new investments (specifically Oil &Gas sector)
- The prices for electricity production are the cheapest amongst all 4 geographies.

AUSTRALIA
- Geographic positioning of the country allows production of considerable amount of Renewable energy, specially produced by wind source.
- Available infrastructure is currently limited, relying heavily on coal and gas in its energy mix, however with recently introduced climate targets and ambitions for clean fuel production – this is expected to change.
- Competitive costs for RE production

RE Cost and Availability by Country, 2030 view



Source: Guidehouse Analysis, IEA Global Energy Outlook 2023

2030 view	US Gulf Coast	North Africa	Middle East	Australia
Potential quantity				
Available infrastructure (current view)				
Range of cost				

Strength relative to other exporting countries Strong Medium Low

Electricity

Global Feedstock Review – RE Electricity

All considered countries have set ambitious targets for RE expansion and possess sufficient potential amounts for production of clean fuels

Region	Availability 2030	Drivers	Challenges
US Gulf Coast	★★★ 290 TWh	• High renewable potential. • Relatively low price for renewable electricity. • Decreasing installation costs, boosted by supporting national policies and incentives (IRA, BIL).	• Availability of electricity with a high load factor for scaled up production of e-fuels. • Competition for the feedstock from another use cases, such as electrification of intensive industries.
North Africa	★★☆ 165 TWh	• High renewable potential and land availability • Geographical proximity with Europe • Lower energy costs.	• Current heavy reliance on fossil fuels and low renewable resources deployed. • Lack of access to affordable finance, technological expertise, infrastructure development, and stable policy frameworks. • Lack of appropriate infrastructure.
Middle East	★★☆ 173 TWh	• High renewables potential and land availability • Investment capacity of public actors historically positioned in the oil and gas sectors	• The required pace for RE infrastructure roll-out to meet NZ targets. • Political instability and conflicts.
Australia	★☆☆ 85 TWh	• High renewables potential • Supportive policy framework • Competitive costs of renewable electricity	• High competition with already well-established fossil fuel infrastructure. • Foreseen grid congestion. • Initial installation costs.

Guidehouse analysis, IEA

Global Feedstock Review – Biogas

Biogas

All regions could make significant contribution to global growth if enough public support is obtained to launch development of the sector

Key take-aways and trends

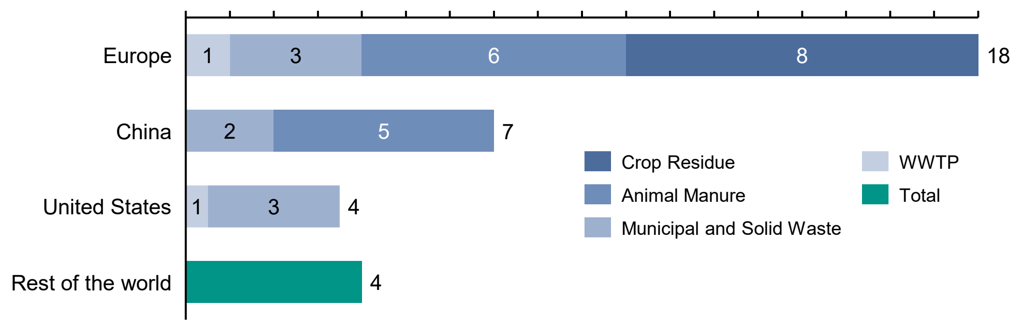
- The global availability of the feedstock for biogas and biomethane production is immense, but largely untapped.
- Currently, biogas production is unevenly spread across the globe: Europe, China and US accounting for 90% of global production.
- At the moment only US and Australia have biogas relevant policies and included biogas targets in their decarbonization plans:
  - US Environmental Protection Agency (EPA) rule for Renewable Fuel Standard (RFS), including guidelines for biogas reform and bio-intermediates.
  - Australia's Emission Reduction Fund (ERF) granting credits per tonne of carbon stored or abated, supporting biogas projects development.

Feedstock Trends and Availability outlook

- According to IEA Net Zero Emissions by 2050 Scenario, production of biogas should rise 4 times by 2030. The growth rate should accelerate to 32% from 2023-2028, an even higher pace is required to meet Net Zero Objectives for 2030.[1]
- All regions could make significant contribution to global growth if enough public support is obtained to launch development of the sector.
- The worldwide availability of sustainable feedstocks for biogas and biomethane is sufficient to produce these gases but largely untapped. (570Mtoe, comparing with actual 35 Mtoe).[2]
- The main feedstock for biogas production include: crop residues, animal manure, municipal solid waste, wastewater and – for direct production of biomethane via gasification – forestry residues.
- Crop residues is the dominant feedstock in all considered regions, followed by animal manure.
- While currently biogas is primary used for power and heat sectors, by 2040 the dominant use will be to produce upgraded biomethane (206 Mtoe in NZ scenario and 78 Mtoe in the stated policies scenario).

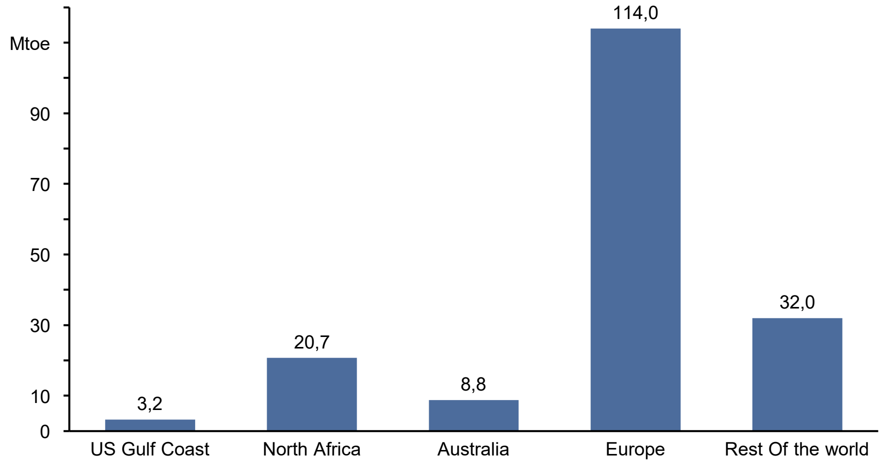
1. IEA, Biogas and Biomethane
2. IEA, Outlook for biogas and biomethane. Prospects for organic growth

Biogas Production by region and feedstock type, 2018



IEA: Guidehouse Analysis,Outlook for biogas and biomethane

Production potential for biogas by region, 2018



Total Africa biogas potential is 59 Mtoe. North Africa biogas quantity estimated, considering the share of biogas potential of the continent, which is 35%.
Australia's potential for biogas production is 375 PJ (ENEA), equivalent 8.8 Mtoe (ENEA Australia biogas outlook)
Texas biogas potential is estimated to be 122.67 billion cuft, equals to 3.2 Mtoe,

Guidehouse outwit complexity

Feedstock potential by region - Biogas

Biogas

North Africa having the greatest potential to produce biogas if relevant infrastructure is developed

USA (Gulf Coast)

- Texas is 2nd state in the US in terms of biogas production potential. Currently biogas is used for electricity production and represents 36 TWh/year.
- Biogas RNG (renewable natural gas cluster) projects represented 91% of all new projects that came online in 2023.[1]
- The price of derived biomethane in the USA is one of the most competitive motivated by federal and state support.

NORTH AFRICA

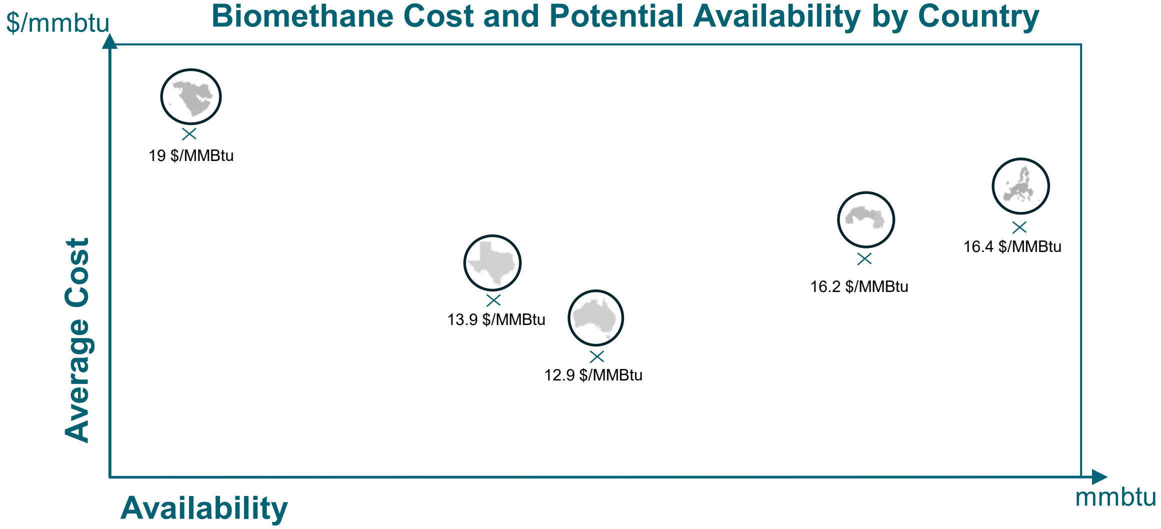
- The main feedstock for biogas production in North Africa is agricultural residues, municipal solid waste and animal manure.
- Countries like Morocco and Egypt are leaders in the region for its production. The total biogas installation in this region account for 3,259 with biogas potential of 20.7 Mtoe.

MIDDLE EAST

- There is a large untapped potential for biogas generation in the Middle East which is mainly contributed by municipal solid wastes, sewage, industrial wastes and farm wastes. However, biogas potential of this geography is hard to estimate, considering restricted available information.
- UAE has rolled out its first biogas production plant, with generation capacity of 1.3 MW . Yemen is on stage of piloting biogas projects for clean energy production.

AUSTRALIA

- Australia has vast resources for its disposal, deriving its biogas from landfill (53%), followed by sewage WWTP (21%) and industrial waste (14%).
- If all available feedstock is mobilized, an estimated biogas potential of the country becomes 103TWh (371PJ).[3] Most of biogas production is used for heat and electricity generation. As of today there is only one demonstration biogas upgrading plant available.
- Costs of biomethane in Australia are one of the lowest, thanks to the available infrastructure and national support.



Source: IEA, Sustainable supply potential and costs

2030 view	US Gulf Coast	North Africa	Middle East	Australia
Potential quantity				
Available infrastructure (current view)				
Range of cost				

Strength relative to other exporting countries: Strong / Medium / Low

1. American Biogas Council
2. Mapping of biogas production potential from livestock manures and slaughterhouse waste: A case study for African countries
3. ARENA, Biogas opportunities for Australia

Feedstock potential by region

Biogas

The global availability of the feedstock for biogas production is immense, but largely untapped

Region	Potential quantity	Drivers	Challenges
US Gulf Coast	3.2 Mtoe	• Available incentives and public policies (Renewable Portfolio Standards (RFS)). • Competitive price of biomethane production. • High availability of feedstock and investments in new bioenergy plants.	• Divert losses of potential feedstock for biogas production. • High initial project costs.
North Africa	20.7 Mtoe	• North Africa has already rolled-out some infrastructure for biogas production. • Supporting policies for renewables productions.	• Even though the potential is huge, currently there is no sufficient infrastructure for its production. • Competition for biogas usage (heating/cooking).
Middle East	unknown	• Large potential, contributed by municipal solid waste, sewage, industrial wastes and farm wastes.	• Lack of sufficient infrastructure, sufficient capital and appropriate supporting policies.
Australia	8.8 Mtoe	• High potential for biogas production. • High investment opportunity.	• The approval process has to be simplified. • The feedstock quality and quantity.

Guidehouse analysis, IEA, without Europe

Table of contents

New gases – delivered costs

-Key assumptions-

LNG

E-methane

Hydrogen (LH2, Green & Blue converted to NH3)

e-Ammonia

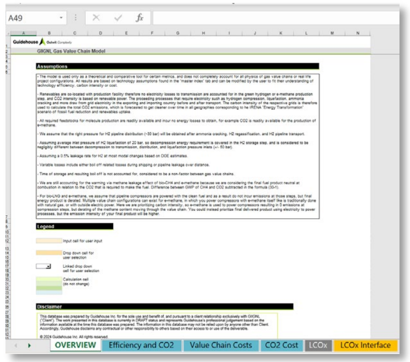
Methodology: LCOx & delivered cost model

The model is built for users to run their own LCOx scenarios and interpret differences between regions and gases, **detailed assumptions are to be shared along with the model via Excel**

Data workbook → LCOx → Delivered cost per value chain steps → Interactive LCOx Tool

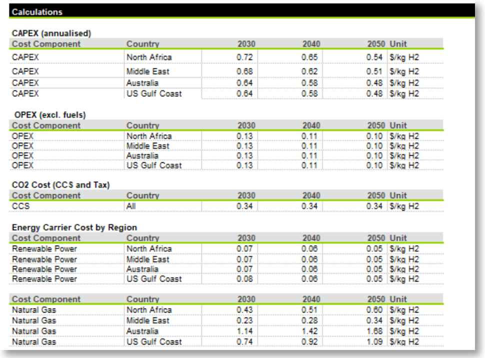
Data workbook

- A suite of assumptions are made on **cost of each value chain technology included.** A general evolution is assumed across 2030, 2040, and 2050.
- **Values are presented as $/MMBtu average levalised costs** typically in the middle of a range of reported costs. Guidehouse chose the most realistic assumptions for the presented base case.



LCOx

- Financial assumptions are made across technologies and regions including capacity factors, CAPEX, OPEX, WACC, storage, oversizing needs and more to calculate detailed LCOx. **Multiple scenarios are built in, related primarily to energy cost and oversizing.**



Calculations

CAPEX (annualised)

Cost Component	Country	2030	2040	2050	Unit
CAPEX	North Africa	0.72	0.65	0.54	$/kg H2
CAPEX	Middle East	0.68	0.62	0.51	$/kg H2
CAPEX	Australia	0.64	0.58	0.48	$/kg H2
CAPEX	US Gulf Coast	0.64	0.58	0.48	$/kg H2

OPEX (excl. fuels)

Cost Component	Country	2030	2040	2050	Unit
OPEX	North Africa	0.13	0.11	0.10	$/kg H2
OPEX	Middle East	0.13	0.11	0.10	$/kg H2
OPEX	Australia	0.13	0.11	0.10	$/kg H2
OPEX	US Gulf Coast	0.13	0.11	0.10	$/kg H2

CO2 Cost (CCS and Tax)

Cost Component	Country	2030	2040	2050	Unit
CCS	All	0.34	0.34	0.34	$/kg H2

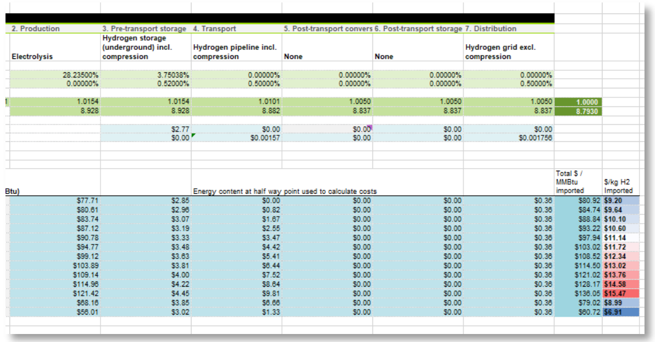
Energy Carrier Cost by Region

Cost Component	Country	2030	2040	2050	Unit
Renewable Power	North Africa	0.07	0.06	0.05	$/kg H2
Renewable Power	Middle East	0.07	0.06	0.05	$/kg H2
Renewable Power	Australia	0.07	0.06	0.05	$/kg H2
Renewable Power	US Gulf Coast	0.08	0.06	0.05	$/kg H2

Cost Component	Country	2030	2040	2050	Unit
Natural Gas	North Africa	0.43	0.51	0.60	$/kg H2
Natural Gas	Middle East	0.23	0.28	0.34	$/kg H2
Natural Gas	Australia	1.14	1.42	1.68	$/kg H2
Natural Gas	US Gulf Coast	0.74	0.92	1.09	$/kg H2

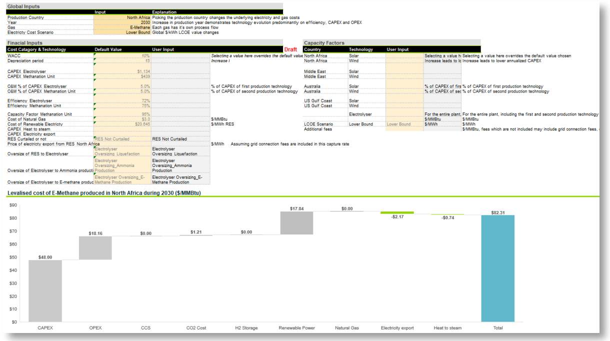
Delivered cost per value chain steps

- Complete value chain costs including LCOx are calculated for each exporting and importing region in scope on a **2024 USD per MMBtu received in the importing country, after one step of distribution** (hydrogen or methane grid).



Interactive LCOx Tool

- A highly customizable LCOx tool will be transferred to GIIGNL members in the coming weeks, **which will allow for comparisons of production costs in various regions and impact on delivered cost of new gases**. The tool can be useful in the optimisation of project parameters or quick hypothetical comparisons.



Methodology: Key Cost Assumptions - LCOx

Detailed scaling and calculations behind cost assumptions presented in the Excel Model

LCOx Financial parameters

- All $ are presented in USD 2024 $
- CAPEX are inflated using the average 2023 CEPCI index (797.9)

Natural Gas Cost	Unit	2030	2040	2050
North Africa	USD/MMBtu	$3.0	$3.6	$4.2
Middle East	USD/MMBtu	$1.6	$2.0	$2.4
Australia	USD/MMBtu	$8.0	$10.0	$11.8
US Gulf Coast	USD/MMBtu	$5.2	$6.5	$7.7
Europe	USD/MMBtu	$8.5	$10.6	$12.5

LCOE (USD/MWh)	Technology	Scenario	2030	2040	2050
North Africa	Solar PV	Lower Bound	$20.64	$16.58	$13.88
Middle East	Solar PV	Lower Bound	$19.48	$15.65	$13.09
Australia	Solar PV & Onshore Wind	Lower Bound	$24.87	$20.82	$17.63
US Gulf Coast	Solar PV & Onshore Wind	Lower Bound	$25.51	$21.28	$18.01
North Africa	Solar PV	Upper Bound	$36.09	$20.90	$17.51
Middle East	Solar PV	Upper Bound	$34.05	$19.72	$16.53
Australia	Solar PV & Onshore Wind	Upper Bound	$40.09	$25.19	$21.57
US Gulf Coast	Solar PV & Onshore Wind	Upper Bound	$41.41	$25.83	$22.08

Country	Technology	Capacity factor
North Africa	Solar	24%
North Africa	Wind	32%
Middle East	Solar	24%
Middle East	Wind	31%
Australia	Solar	22%
Australia	Wind	37%
US Gulf Coast	Solar	20%
US Gulf Coast	Wind	39%

Note : please refer to the data workbook in the Model

WACC (%)	Country	%
	North Africa	10%
	Middle East	9%
	Australia	8%
	US Gulf Coast	8%

Depreciation factor		Years
	All locations	15

CAPEX	Unit	2030	2040	2050
Blue Hydrogen	$/kW H2	1,376	1,238	1,032
Blue Ammonia	$/kW H2	471	424	318
Green Ammonia	$/kW H2	855	855	855
Green Hydrogen	$/kW H2	1,134	785	558
E-Methane	$/kW CH4	439	319	279

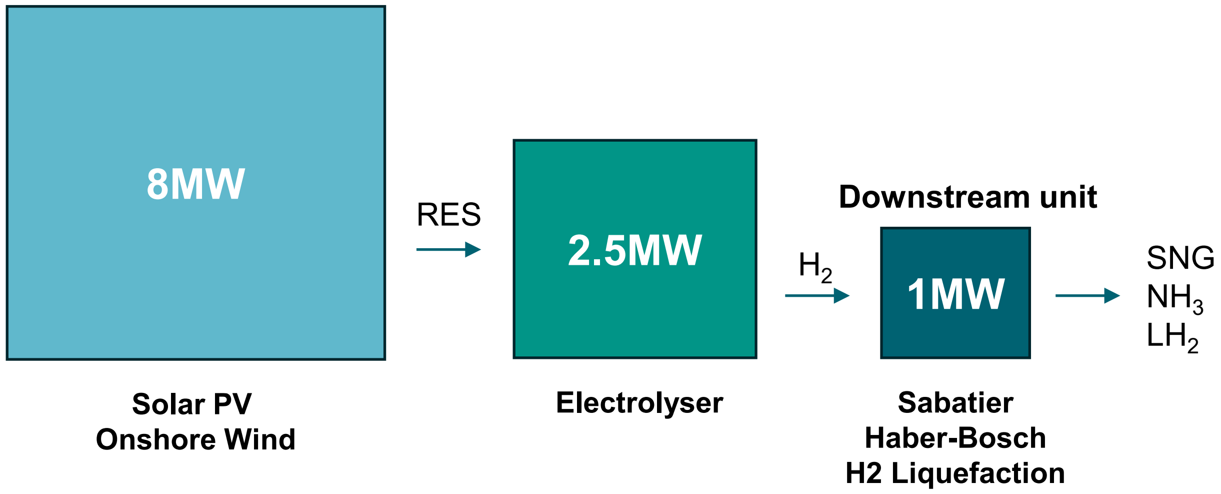
OPEX as a % of CAPEX	Unit	2030	2040	2050
Blue Hydrogen	% of CAPEX	2.3%	2.3%	2.3%
Blue Ammonia	% of CAPEX	4.7%	4.7%	4.7%
Green Ammonia	% of CAPEX	4.7%	4.7%	4.7%
Green Hydrogen	% of CAPEX	5.0%	5.0%	5.0%
E-Methane	% of CAPEX	5.0%	5.0%	5.0%

Efficiency of process	Unit	2030	2040	2050
Blue Hydrogen	%	80%	80%	80%
Blue Ammonia	%	70%	78%	78%
Green Ammonia	%	62%	66%	71%
Green Hydrogen	%	72%	75%	80%
E-Methane	%	75%	79%	85%

Oversizing for green molecule production

Oversizing of RES and electrolysers is assumed to maintain near full time gas production

Optimal ratio of value chain capacities determined by 8760 analysis:



Average Capacity Factors (%) - Dedicated Solar PV oversizing Example

Solar PV	Electrolyser	Downstream unit
24%	37%	95%

Solar PV with an average CF of 24% oversized by 3.2 compared to the electrolyser gives an electrolyser CF of 37%, which is oversized by 2.5 compared to the downstream unit achieving a final capacity factor of ~95%.

These oversizing ratios are working into the final LCOx calculations presented.

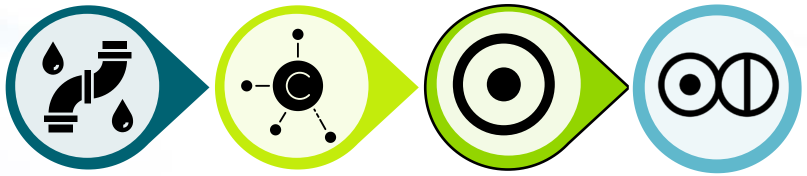
Key messages

- E-methanation, ammonia production, and H2 liquefaction technology cannot typically ramp up and down in operation and temperature at risk of damaging technology such as catalysts.
- For all clean gas value chains involving electrolysis, we have studied various levels of oversizing of electrolyser and RES **to achieve a near complete (95%) capacity factor on the downstream process**.
- In order to achieve a consistent capacity factor on the downstream process, a typical 8760 solar PV production profile in North Africa was used to determine the average requirement of oversizing in each production region, which are on similar latitudes.[1]
- The **optimal ratio of oversizing was found to be 1 : 2.5 : 8 downstream unit to electrolyser to RES capacity.** A similar result was also in a report on clean ammonia[2]
- We have also studied cases of no oversizing, which often calculate a slightly less expensive LCOx, **but we do not present them in final results due to feasibility concerns**. Additional operational strategies such as hot-standby can be implemented at a cost to maintain catalyst integrity and future developments are expected in this domain.[3]

[1]**CAVEAT:** We are assuming that all hydrogen is produced by solar PV in all regions for simplicity's sake, dedicated hybrid production profiles including wind should be considered.
[2]Techno-economic assessment of blue and green ammonia
[3]Cost benefits of optimizing hydrogen storage and methanation capacities

New gases – delivered costs

-Results from the modelling tool-



LNG

E-methane

Hydrogen (LH2, Green & Blue converted to NH3)

e-Ammonia

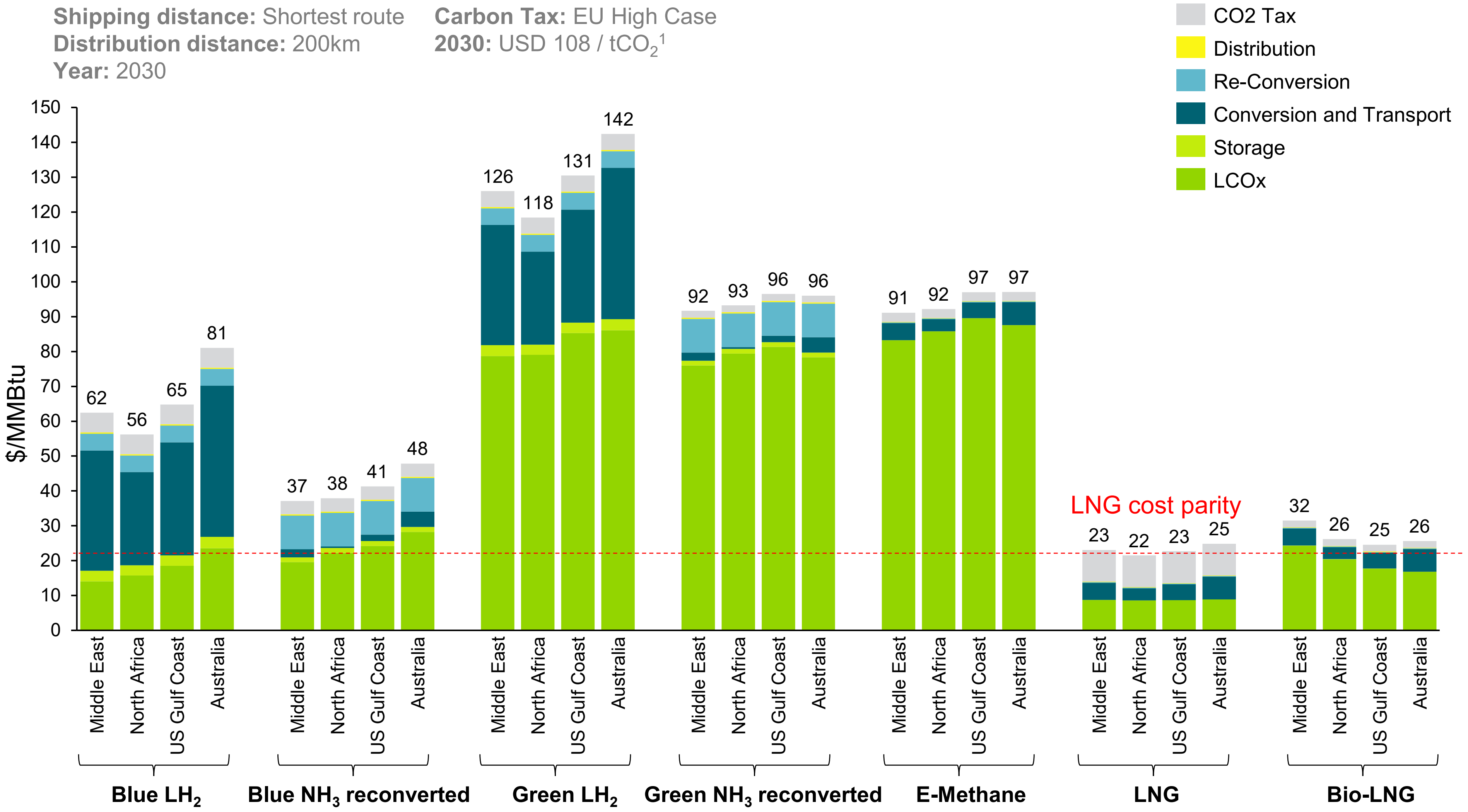
Delivered cost of new gas molecules to Europe in 2030

In 2030, most green hydrogen-based gases are non-competitive with natural gas-based molecules

Delivered cost of new gasses to Europe 2030 ($/MMBtu delivered)

Shipping distance: Shortest route
Distribution distance: 200km
Year: 2030

Carbon Tax: EU High Case
2030: USD 108 / tCO_2[1]



Key messages

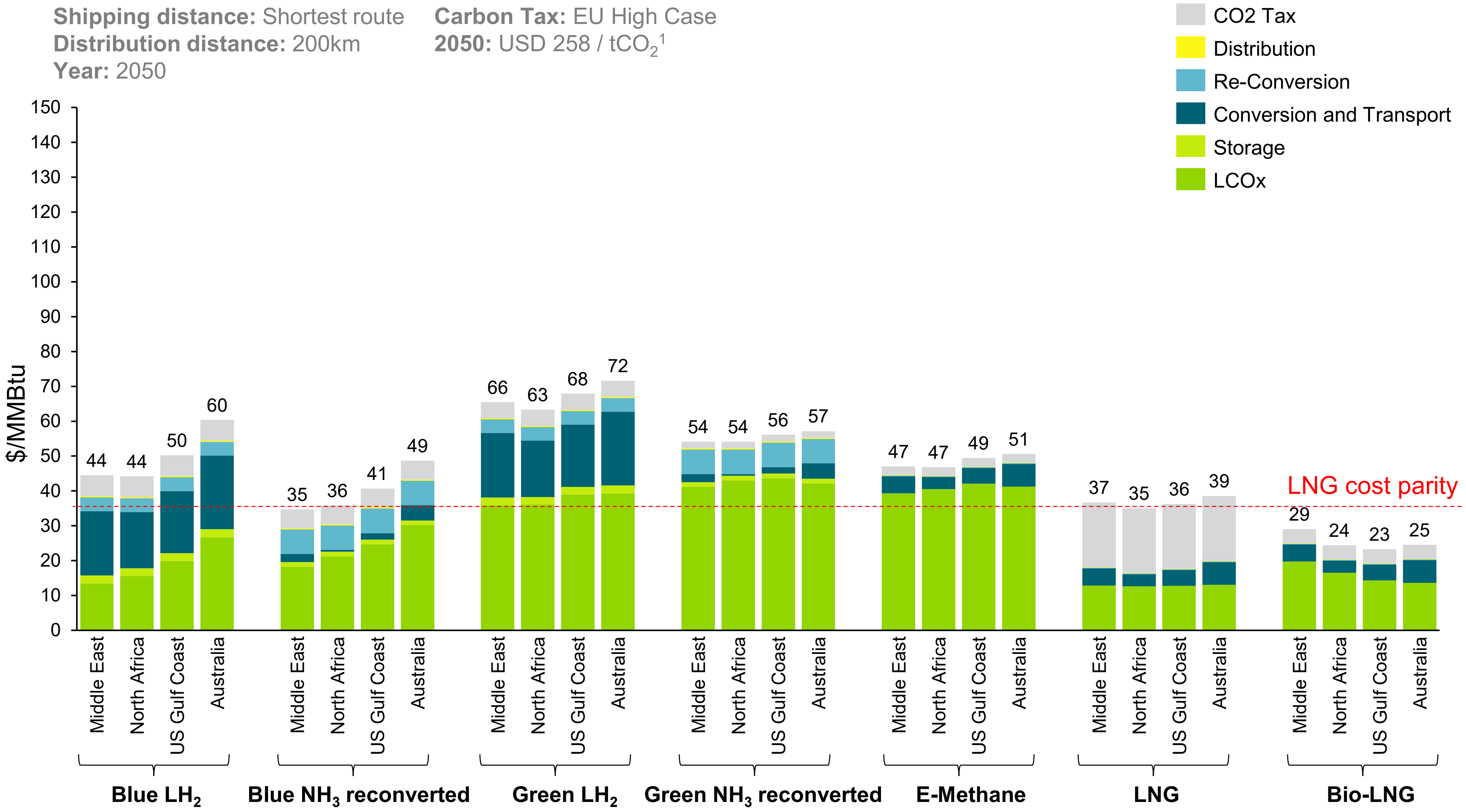
- The cheapest imports are expected to come from Middle East and North Africa for most new gases, due to low-cost solar resource and shorter transport distances compared to US Gulf Coast and Australia.
- Liquefaction and high boil off make liquid hydrogen more expensive than ammonia-based value chains.[2]
- In 2030, blue ammonia and liquid blue hydrogen value chains are more cost competitive than green hydrogen-based value chains due to massive oversizing needs and high electrolyser CAPEX.
- LNG LCOx is based on an average spot price forecast in Europe to compare against the alternative to clean gas imports.

Guidehouse analysis 2024. [1]S&P Carbon Tax
Energy prices and capacity factors vary by region. Oversizing dimensions are the same for liquified green hydrogen, green ammonia, and e-methane.[2]liquefaction of hydrogen is included in the Conversion and Transport bar, re-conversion incudes regassification and ammonia cracking. Excluding transportation by Pipeline

Delivered cost of new gas molecules to Europe in 2050

With a high carbon tax, blue ammonia re-converted and bio-LNG become competitive with LNG

Delivered cost of new gasses to Europe 2050 ($/MMBtu delivered)



Key messages

- The cheapest imports are expected to come from Middle East and North Africa for most new gases, due to low-cost solar resource and shorter transport distances compared to US Gulf Coast and Australia.
- Liquefaction and high boil off make liquid hydrogen more expensive than ammonia-based value chains.[2]
- In 2050, e-methane import to Europe is more cost-effective than other green hydrogen-based value chains and long-distance liquid hydrogen transport (LH_2).
- LNG LCOx is based on an average spot price forecast in Europe to compare against the alternative to clean gas imports.

Guidehouse analysis 2024. [1]S&P Carbon Tax
Energy prices and capacity factors vary by region. Oversizing dimensions are the same for liquified green hydrogen, green ammonia, and e-methane.[2]liquefaction of hydrogen is included in the Conversion and Transport bar, re-conversion incudes regassification and ammonia cracking. Excluding transportation by Pipeline

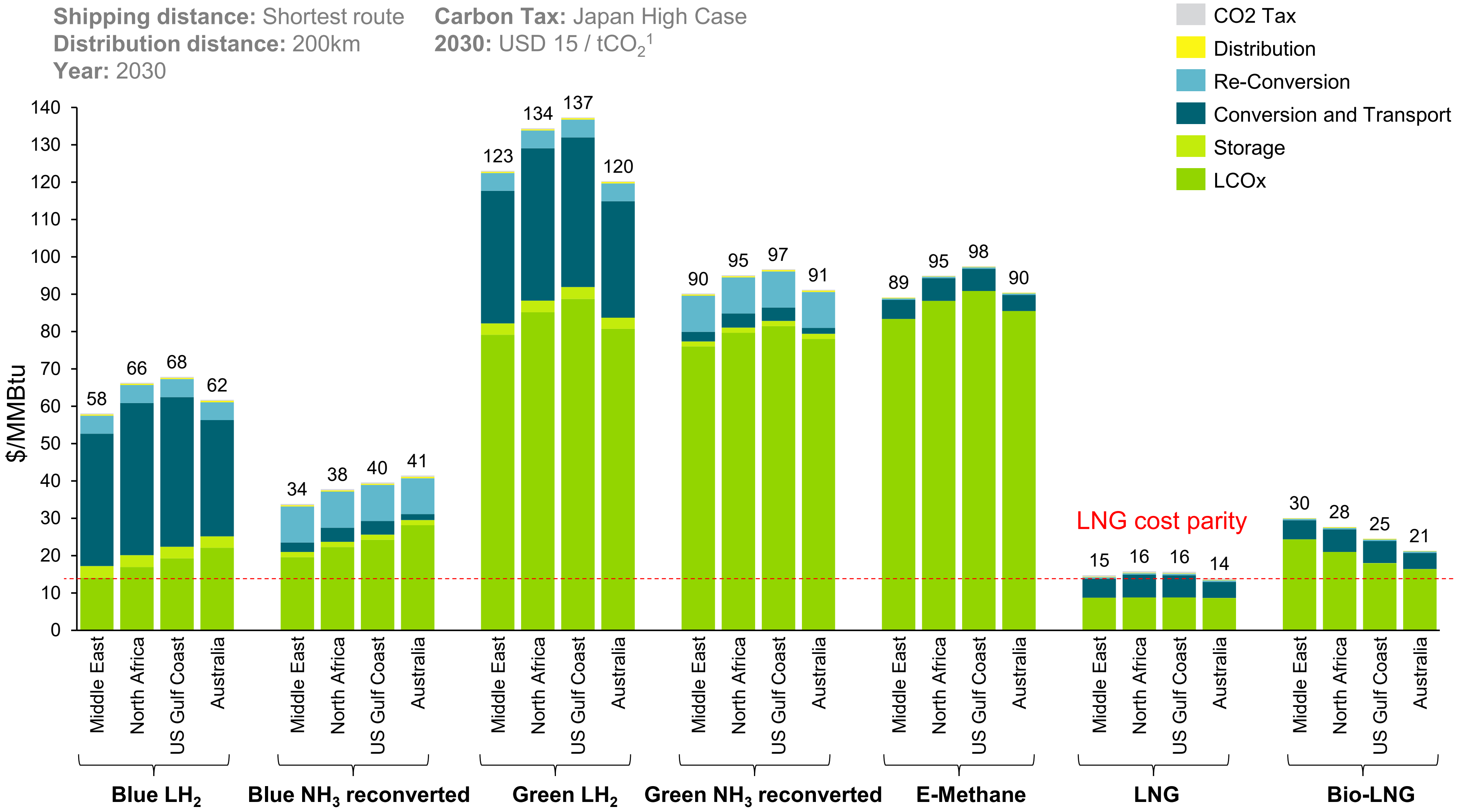
Delivered cost of new gas molecules to Japan in 2030

In 2030, the gap between LNG cost and green hydrogen-based molecules and LH_2 is large

Delivered cost of new gasses to Japan 2030 ($/MMBtu delivered)

Shipping distance: Shortest route
Distribution distance: 200km
Year: 2030

Carbon Tax: Japan High Case
2030: USD 15 / tCO_2[1]



Key messages

- With a lower carbon tax expected than Europe, LNG remains more cost competitive in 2030 compared to all new gases.
- Bio-LNG, blue LH_2 and ammonia are the most cost competitive new gases.
- Australia is the most competitive supplier of green hydrogen-based value chains including e-methane due to proximity and high solar irradiance. Australia also has a lower assumed WACC which contributes to a lower LCOx.
- Technology improvements are needed to make green hydrogen value chains more competitive with LNG.

Guidehouse analysis 2024. [1]Extrapolation from $12/tCO2 target in 2030 out to 2050 using the same growth rate as EU high case. S&P Carbon Tax
Energy prices and capacity factors vary by region. Oversizing dimensions are the same for liquified green hydrogen, green ammonia, and e-methane.

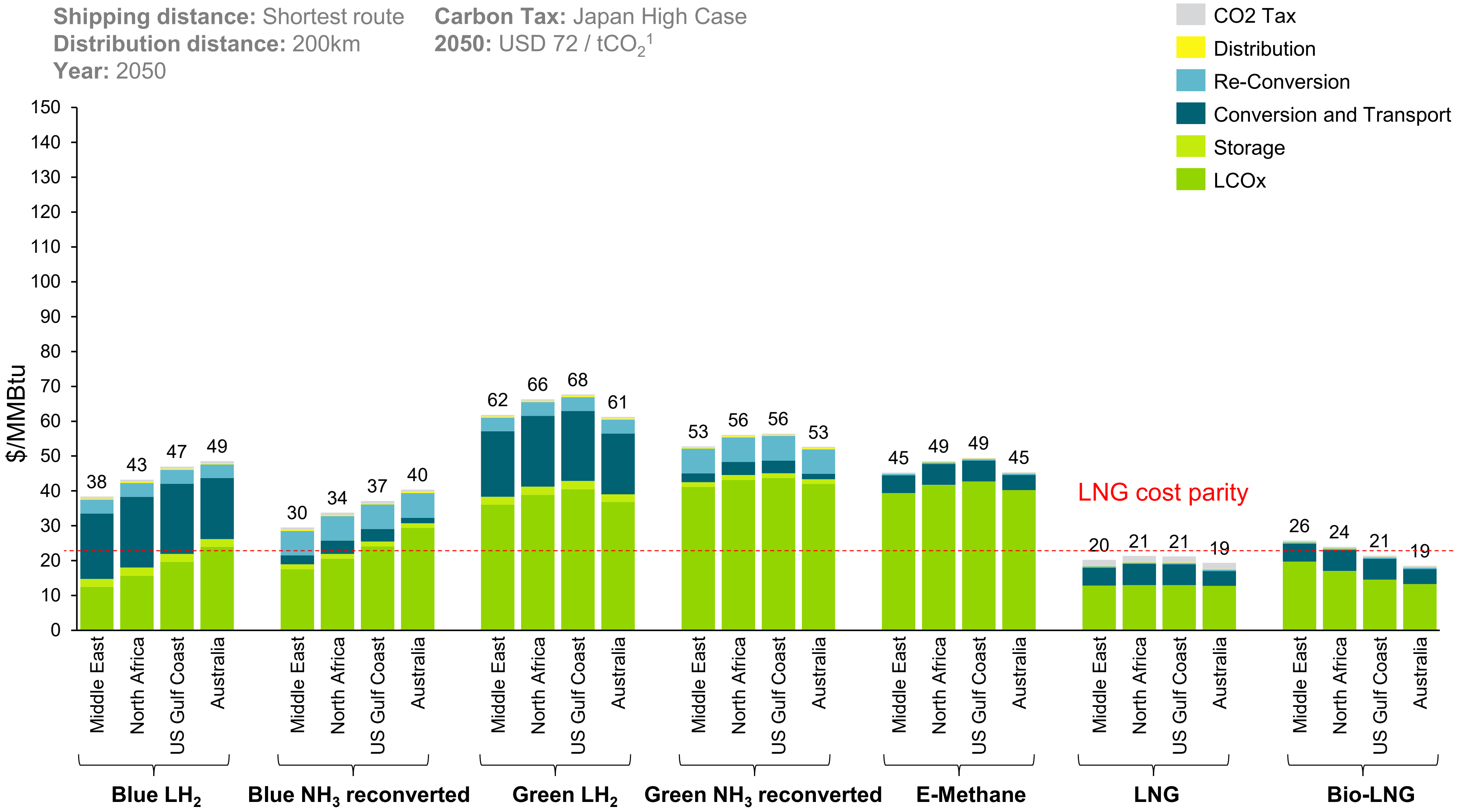
Delivered cost of new gas molecules to Japan in 2050

Blue ammonia, liquid blue hydrogen, bio-LNG and e-methane are the most cost competitive

Delivered cost of new gasses to Japan 2050 ($/MMBtu delivered)

Shipping distance: Shortest route
Distribution distance: 200km
Year: 2050

Carbon Tax: Japan High Case
2050: USD 72 / tCO_2[1]



Key messages

- With a lower carbon tax expected than Europe, LNG remains more cost competitive in 2050 compared to most new gases.
- Australia is the most competitive supplier of green hydrogen-based value chains including e-methane due to proximity and high solar irradiance. Australia also has a lower assumed WACC which contributes to a lower LCOx.
- Other factors are likely to drive the preference for import of new gasses to Japan, such as large existing infrastructure base for regassification, pipelines, and gas fired power production.

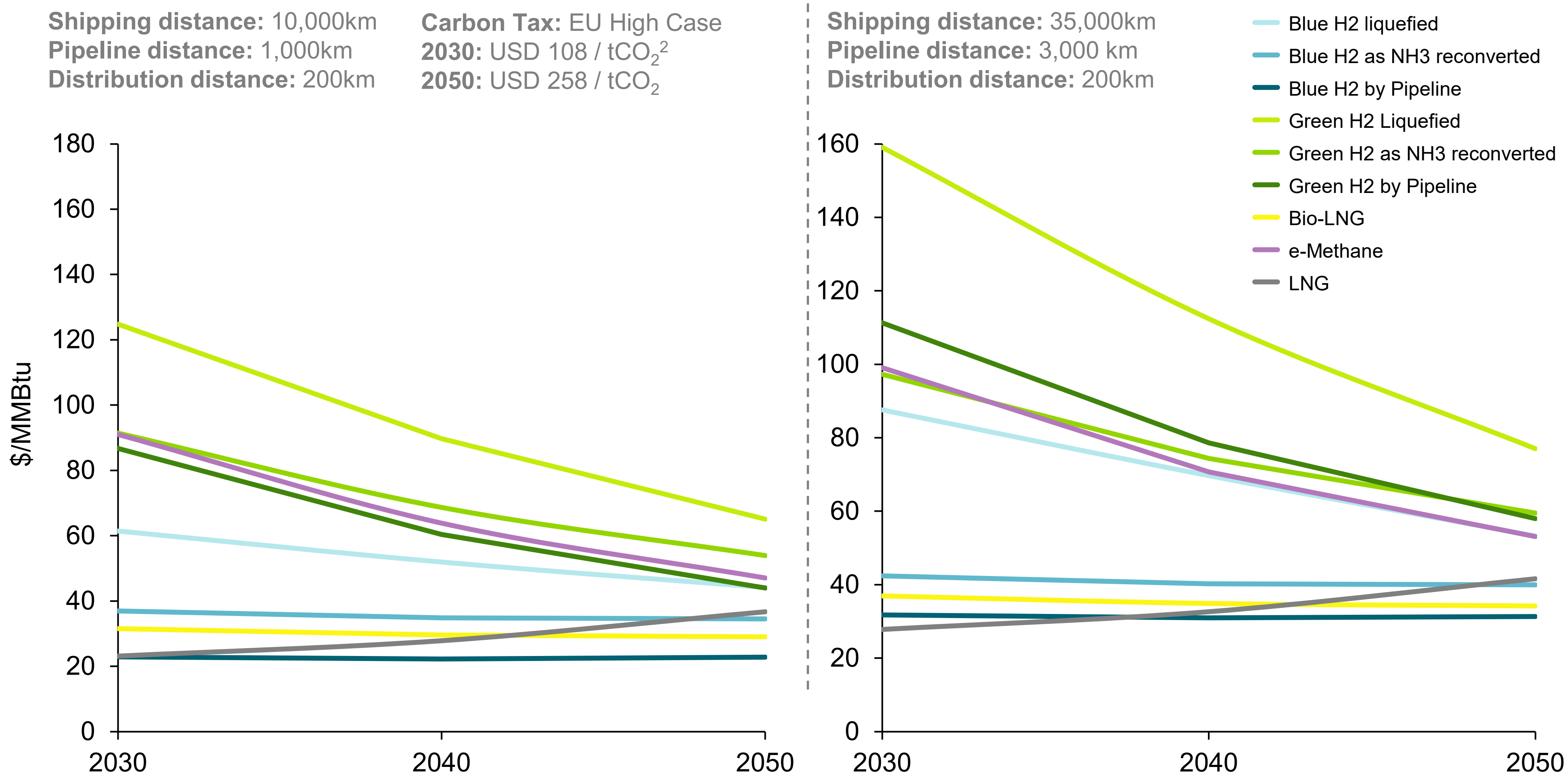
Guidehouse analysis 2024. [1]Extrapolation from $12/tCO2 target in 2030 out to 2050 using the same growth rate as EU high case. S&P Carbon Tax
Energy prices and capacity factors vary by region. Oversizing dimensions are the same for liquified green hydrogen, green ammonia, and e-methane.

Guidehouse outwit complexity

Delivered cost of new gas molecules per year

Costs mostly reduce over time due to technology improvements, particularly hydrogen and e-methane gas value chains since they are currently the lowest TRL

Delivered cost of new gasses over time at two different distances ($/MMBtu delivered)[1]



Key messages

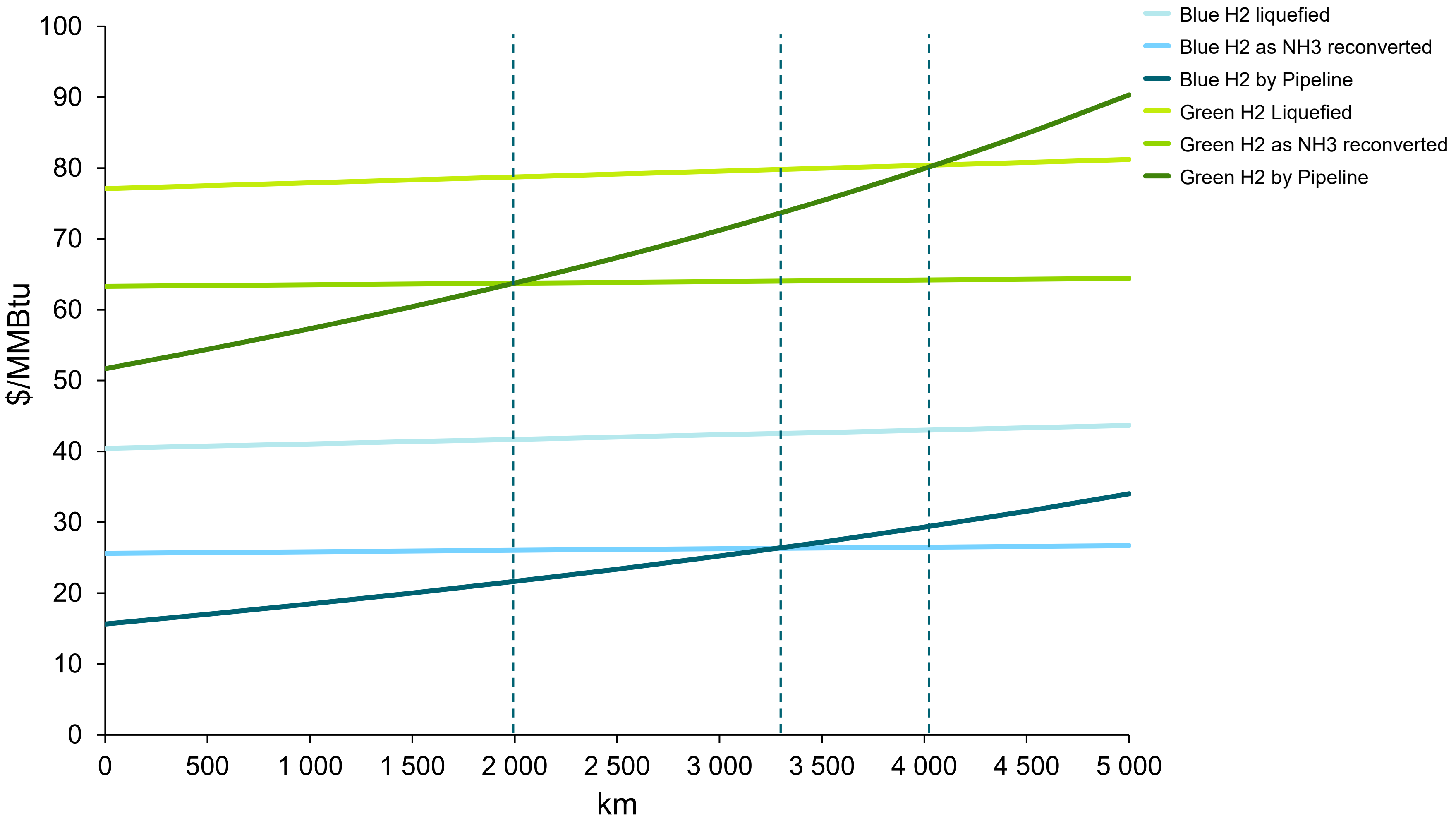
- Large cost reductions are expected for hydrogen-based value chains due to dramatic improvements in electrolyser CAPEX (from ~$1,150 in 2030 to ~$550 $/kW H_2 in 2050) and technology efficiency such as liquefaction.
- Liquid green hydrogen, green ammonia, and e-methane remain expensive relative to other gasses because of the need of oversized RES, electrolyser capacity, and on-site hydrogen storage to maintain a high gas production load factor.
- LNG is typically the cheapest gas even towards 2050[3], but blue hydrogen transported by pipe, bio-LNG, and to a lesser extend blue ammonia are quite competitive.

Guidehouse analysis 2024. [1]Production country costs and carbon intensity set to Middle East and importing country is Europe. [2]EU high carbon tax scenario assumed. [3]Energy prices and capacity factors vary by region. Oversizing dimensions are the same for liquified green hydrogen, green ammonia, and e-methane.

Cost of delivered gas based on distance

Hydrogen pipelines are the most cost effective for hydrogen delivery up to 3,000 km

Delivered cost of clean hydrogen by distance - 2040 $/MMBtu



Key messages

- Up to 2,000km, the most cost-effective way to transport green hydrogen via pipeline in 2040.
- After 2,000km it is more cost effective to transport green hydrogen as green ammonia an reconvert into hydrogen at the end destination than transport via pipe due to higher leakage rate of hydrogen pipelines compared to almost no leakage and higher efficiency of the ammonia value chain. After 4,000km it is even more cost effective to transport green hydrogen in liquid form due to high leakage.
- Oversizing dimensions are the same for liquified green hydrogen, green ammonia, and piped green hydrogen. Although, if no oversizing is assumed for piped green hydrogen due to having no downstream transformation unit, it remains more cost effective than all other transport methods up to 4,000km.
- Blue hydrogen is more cost effective than green hydrogen, and remains more cost effective than ammonia or liquified transport over longer distances because of a lower LCOx to losses ratio compared to green hydrogen.

Guidehouse analysis 2024. [1]No carbon tax assumed. Energy prices and capacity factors vary by region.

Table of contents

Methodology: Scope of flow study

Work package quantifying the potential export of new gases on 8 corridors from 4 exporting regions towards Europe and Japan

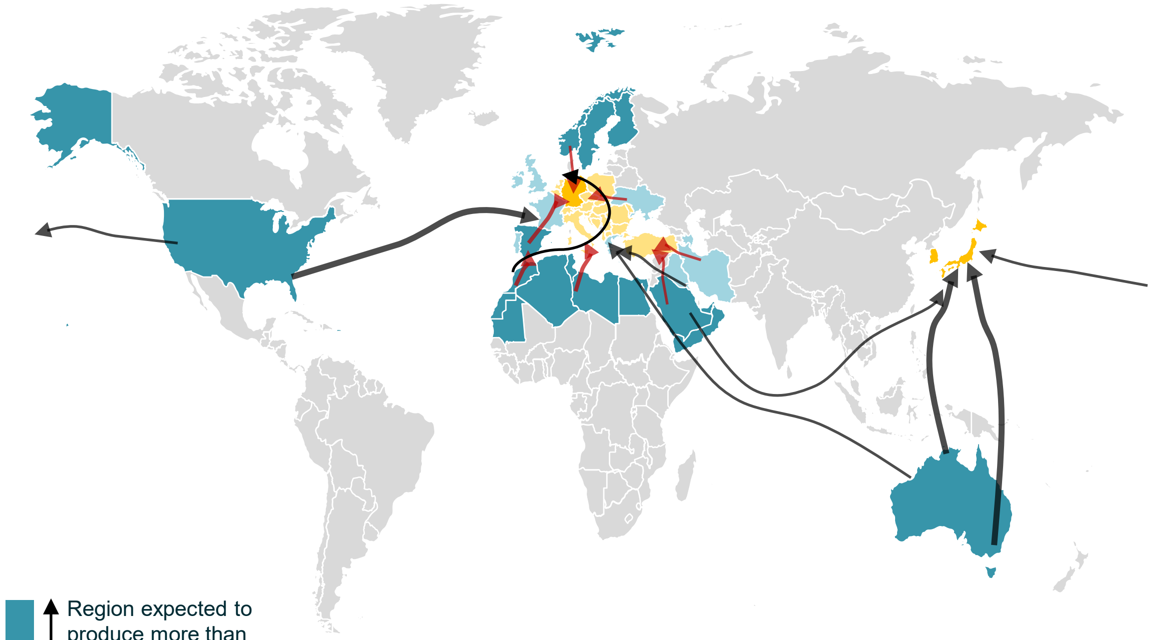
4 Exporting regions	New gases flow	2 Importing regions
US Gulf Coast:	Green H_2 as NH_3	
	Green H_2 Liquified	
North Africa	H_2 by pipeline	European Union
	Blue H_2 as NH_3	
	Blue H_2 Liquefied	
Middle East	LNG Bio-LNG E-methane	Japan
Australia		

Note: other flows are out of scope

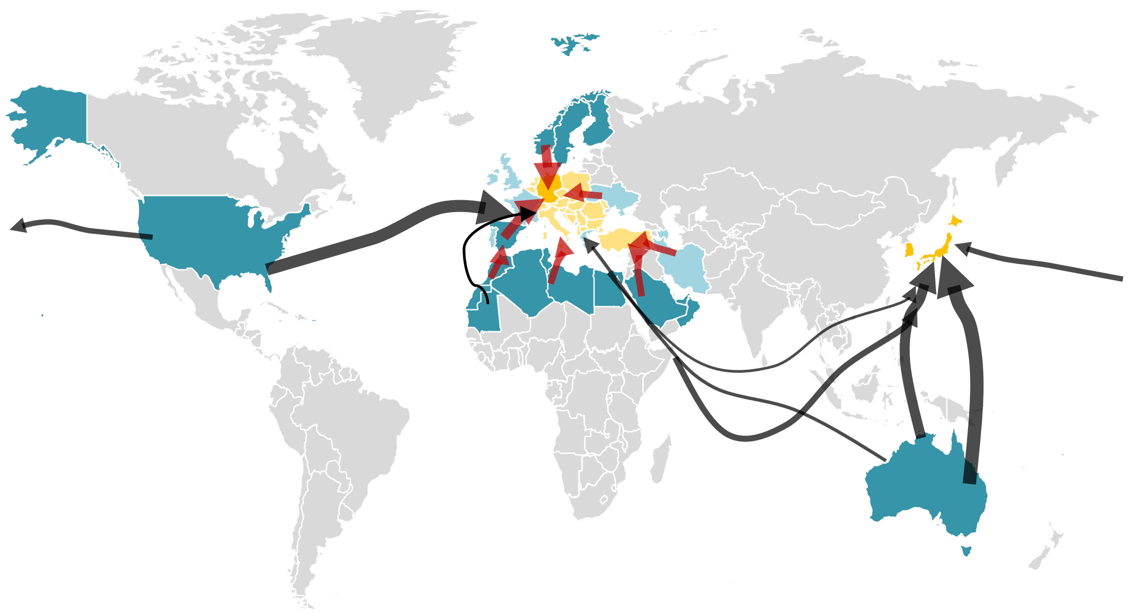
Expected trade : H2 and its derivatives

Europe and Japan both has set ambitious targets for hydrogen supply, rapidly developing trade routes with exporting countries. By 2050, extensive trade links will allow efficient delivery of required quantities of clean gases.

2030 vs 2050 H_2 and its derivatives flow between considered geographies



Total flow 2030: 7 Mt



Total flow 2050: 52 Mt

Region expected to produce more than consumed

Balanced or non-actors

Region expected to consume more than produced

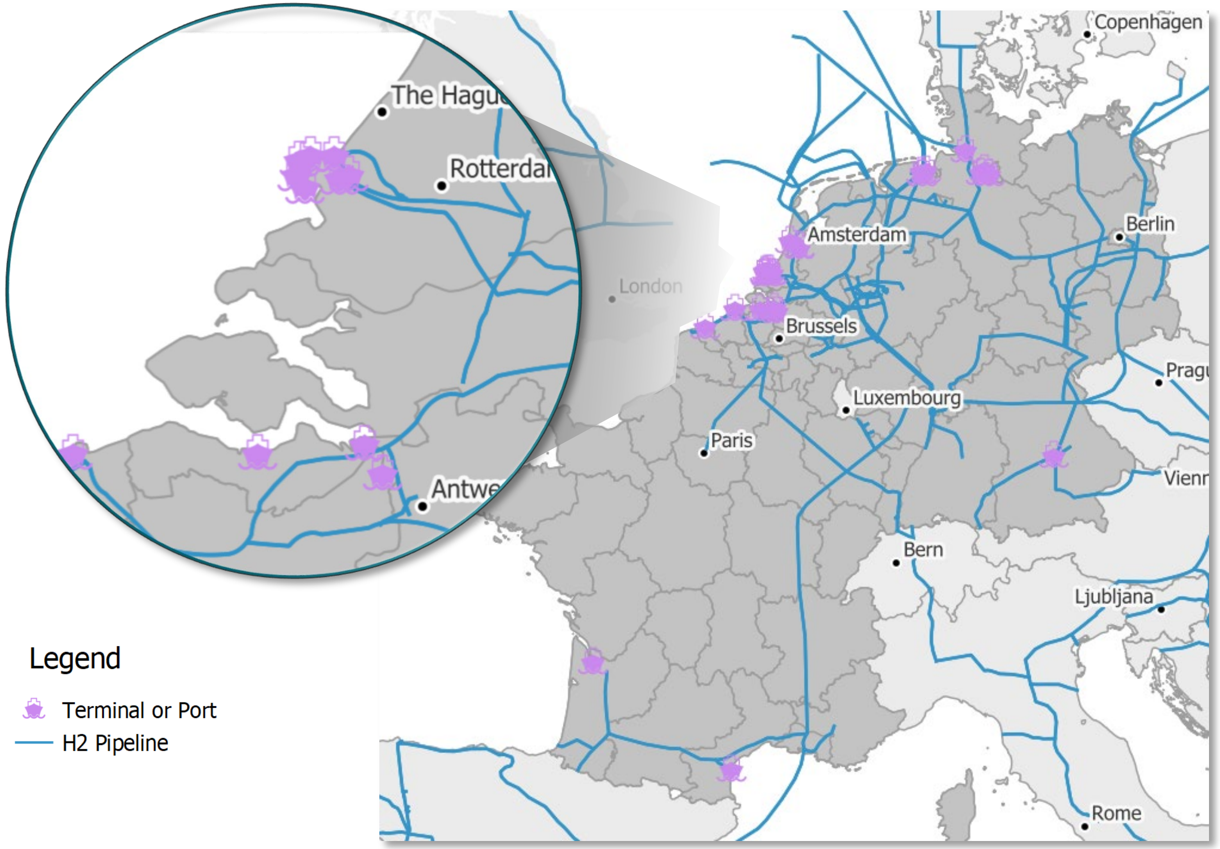
- >10 Mt
- 5-10 Mt
- 2-5 Mt
- 0-2 Mt
- Mostly Piped
- Mostly Shipped

Source : Guidehouse Analysis, only for countries in Scope

European import terminal development timeline

The import of H_2 by sea will depend largely on the import terminal capacities and commercialization of ammonia cracking technology, which is largely unclear but not anticipated before 2032. Antwerp, Rotterdam, and Northern Germany will be first movers.

H_2 import terminal locations and pipelines in study scope countries 2035



Source : Guidehouse Analysis

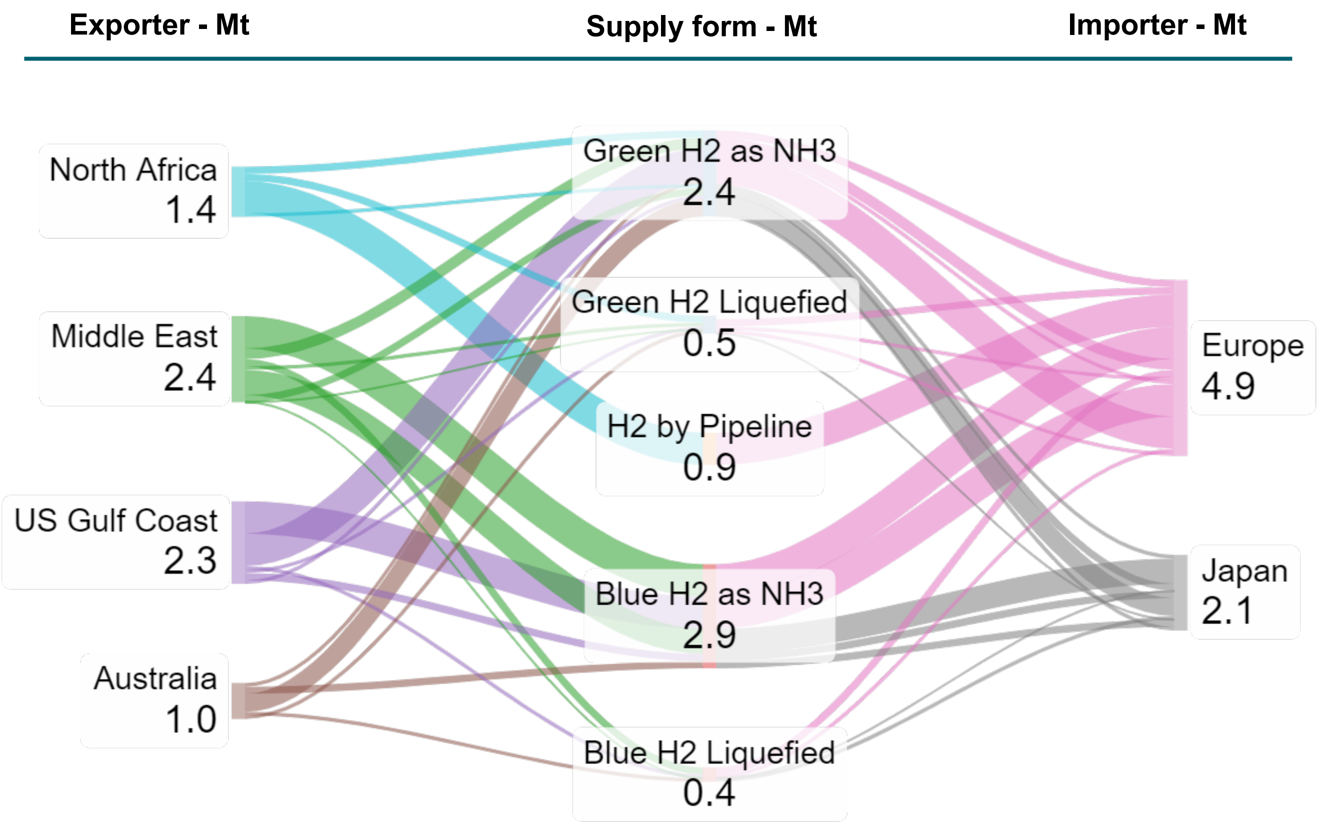
Port Name	Form of H_2	Capacity H_2	Start Year[1]	Phase
Wilhelmshaven (Uniper)	NH_3	9.8 TWh	2030	Feasibility
Wilhelmshaven (bp)	NH_3	Unknown	2028	Concept
Port of Hamburg (Air Products)	NH_3	Unknown	2026	Feasibility
Brunsbüttel (RWE)	NH_3	8.6 TWh	2026	FEED
Port of Amsterdam (Hydrogenious)	NH_3, LOHC	33.3 TWh	2030	Feasibility
ACE Terminal (Vopak)	NH_3	16.6 TWh	2027	Feasibility
Amplifhy ROT (vtti)	NH_3	41.6 TWh	2028	Feasibility
Project Helios[2] (Gunvor)	NH_3	2.7 TWh	2026	FEED
H2Sines.Rdam (Vopak, Engie, Shell)	LH_2	1.2 TWh	2028	Feasibility
Zeebrugge (fluxys)	NH_3	17.7 TWh	2029	Feasibility
Antwerp-Brugges (fluxys)	NH_3	5.9 TWh	2027	Feasibility
Amplifhy Antwerp (vtti)	NH_3	41.6 TWh	2028	Feasibility
Dunkerque LNG (Dunkerque LNG)	NH_3	17.7 TWh	2029	Concept

[1]First derivative imports based on project commissioning target, it is believed that cracking will not reach the announced H_2 capacities until 2032.
[2]Cracking offered by third party once technology scales, cracking efficiency loss of 15% assumed

Global H2 flow overview around 2030

Around 2030, early trade routes are being established, helping to meet emerging demand for hydrogen

2030 Hydrogen supply to chosen geographies (Hydrogen, Mt)



Source: Guidehouse Analysis, only showing the import and export potential between the listed countries, not including the rest of demand met by other exports. [1]Other hydrogen derivatives such as LOHC, methanol and MCH are not studied here, but could be part of the overall share of hydrogen assumed to be transported as ammonia. [2]projects such as the H2Med hydrogen pipeline from North Africa to Europe are planned for 2030, but could be pushed back towards 2035.

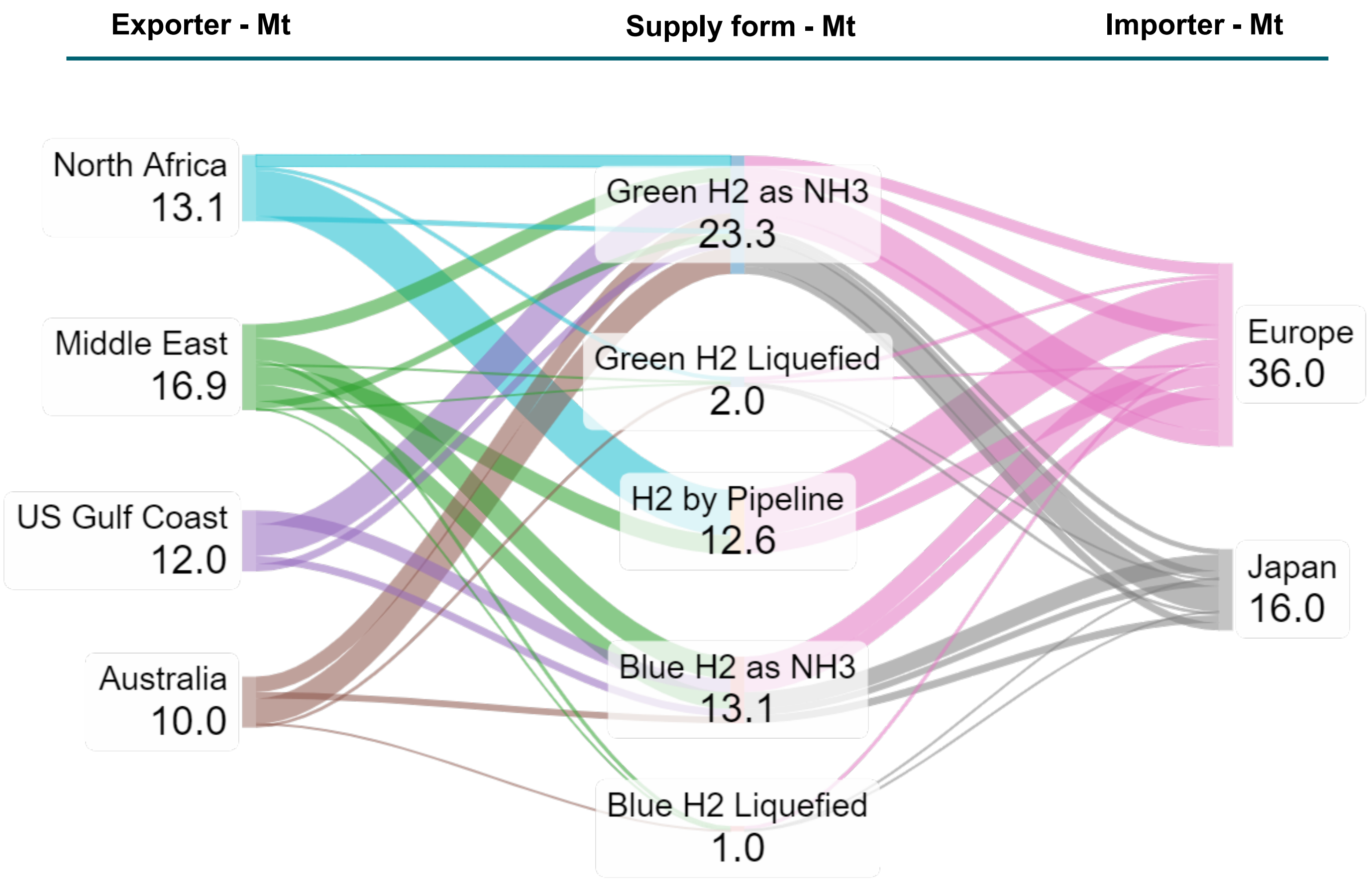
Key messages

- **Demand for clean hydrogen in Europe is ramping up in 2030**, based on early commercial scale hydrogen consumption mostly at steel plants, maritime and aviation sector, and existing refineries. Similarly to EU, **Japan's** h2 demand is driven by need in decarbonization of power sector, industry and transportation.
- A total of 10Mt of clean hydrogen demand is assumed in Europe with half assumed to be met by domestic demand including Norway, and **half imported by the exporting regions included in the study.**
- **Japan's Hydrogen strategy** is expecting demand of **3Mt** H2 by 2030, 40% of which could be met by imports from **Australia**
- Around 2030, **US Gulf Coast and Middle East are expected to begin** supplying mostly blue hydrogen (75% blue hydrogen) to Europe and Japan due to available and relatively cheap natural gas. **North Africa and Australia** are assumed to supply mostly green hydrogen, considering strong RES availability the announced production projects and strategies of these 2 countries.
- Over long distances, **hydrogen transportation** is mostly carried out as **ammonia reconverted into hydrogen**, as it is more efficient and cost-effective compared to the liquefied value chain.[1] This will depend on the commercialisation of ammonia cracking, which is expected to ramp up between 2030 and 2035.
- Hydrogen supply from North Africa towards Europe will be mostly performed via the **planned South H2 and H2Med pipeline leading to Germany via Italy and Spain respectively.**

Global H2 flow overview around 2050

By 2050, hydrogen trade capacities between corridors will increase significantly, reaching up to 50 Mt between MENA - Europe and Australia - Japan

2050 Hydrogen supply to chosen geographies (Hydrogen, Mt)



Source : Guidehouse Analysis

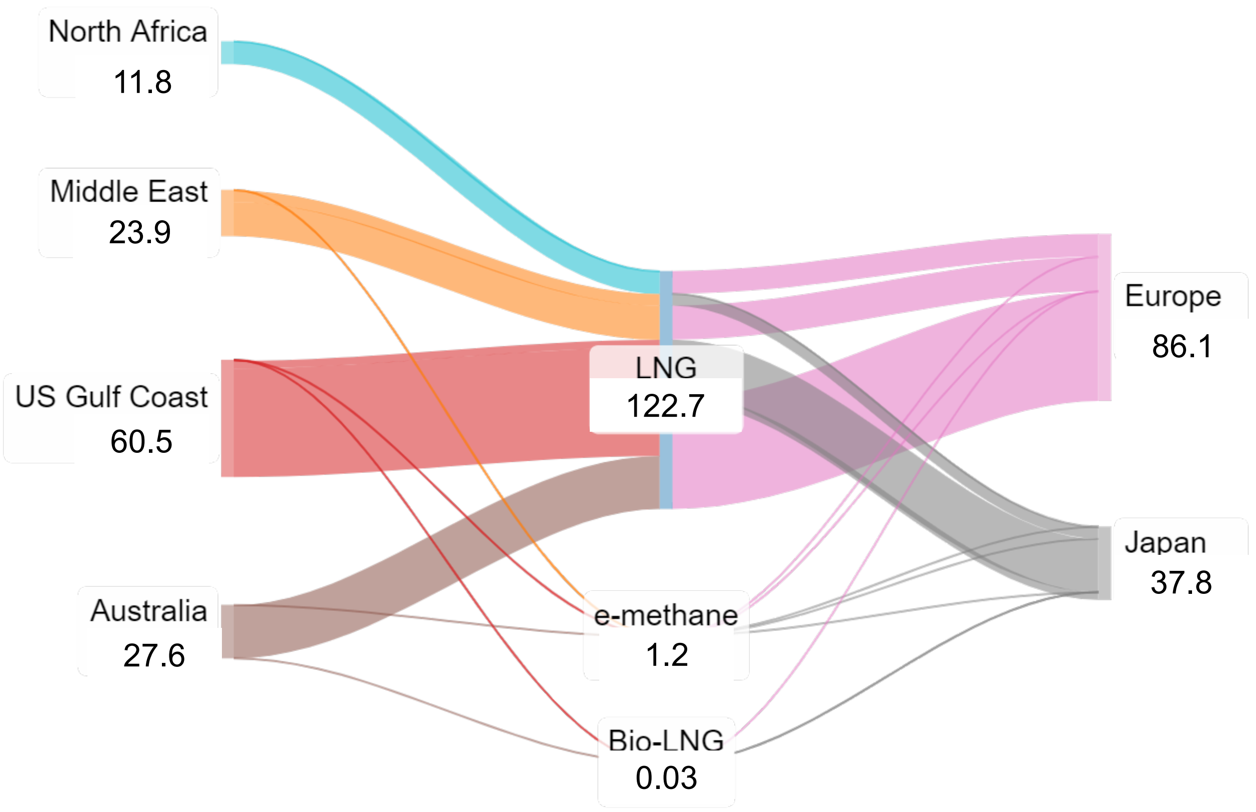
Key messages

- Europe's aggressive shift away from natural gas further increases the role for clean gasses such as hydrogen due to many traditionally gas fired processes becoming hydrogen powered – ie. Gas fired power, metals production, heat production, transport etc.
- **North Africa** and **Middle East** will be the two main suppliers of hydrogen, mostly green, to Europe by 2050 due to high solar resource potential and proximity leading to high-cost effectiveness.
- For **long distance** routes, priority will be given to the shipment of H2 in the **form of ammonia**, which will be dominant form of hydrogen transported due to **expected commercialisation of ammonia cracking technology.**
- **The Middle East will likely deliver most of its hydrogen via shipping as ammonia and reconversion**, as it will be the cheapest option for transport. Some could be delivered through a potential hydrogen pipeline, but economics at the distance of around 3,500km between the EUA and Greece for example begin to deteriorate for piped hydrogen due to high leakage.
- Supply to **Japan** will mainly come **from Australia, followed by the Middle East and US Gulf Coast due to their proximity.**

CH4 flow overview (LNG, Bio-LNG, e-methane), 2030

Around 2030, reliance on LNG will persist in 2 selected geographies, US Gulf Cost playing an important role in its delivery

2030 LNG, Bio-LNG and e-methane supply to chosen geographies (Mt)



Source : Guidehouse Analysis.

Key messages

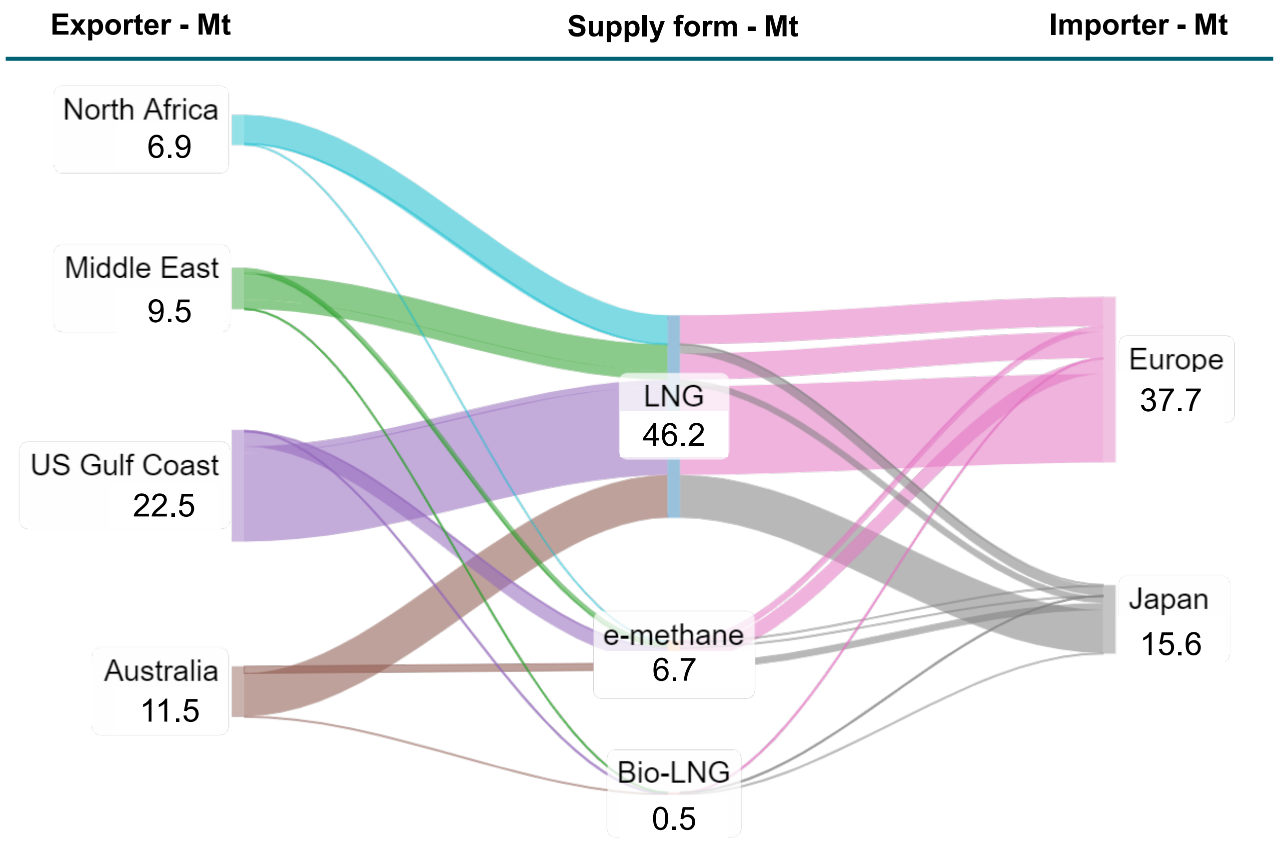
- Around 2030, the two importing geographies will continue their reliance on LNG, however with **lesser demand**, following announced climate transition plans.
- **US Gulf Coast** could play an important role as a supplier of clean gases for the EU, mostly as e-methane based on biogenic CO_2 availability and available subsidies for CO_2 capture in the IRA.
- Existing infrastructure for import of liquefied CH4 based gases in importing geographies facilitate the earliest imports of e-methane and bio-LNG.
- **Australia and US Gulf Coast could supply the earliest quantities of Bio-LNG** to EU and Japan, potentially via blending in existing LNG cargos as quantities of biomethane will be limited and likely consumed domestically to meet emissions reduction demands.
- **E-methane** will be traded in much greater quantities than Bio-LNG, as required feedstock for production is believed to be higher than biomethane.
- In 2030, **North Africa will not deliver** Bio-LNG nor e-methane, as no intentions have been announced and due to the lack of required biogenic CO2.

Estimates were made to calculate proportion of e-methane and Bio-LNG of the total LNG that can be delivered. It was assumed that for the corridor US Gulf Coast – Europe, Bio-LNG proportion represent 3% and for Japan – 3% as well. The overall proportion of clean gases from LNG is 0.5%.

CH4 flow overview (LNG, Bio LNG, E-methane), 2050

By 2050, reliance on LNG will decrease, however proportion of delivered clean gases will increase considerably

2050 LNG, Bio-LNG and e-methane supply to chosen geographies (Mt)



Source : Guidehouse Analysis

Key messages

- **In 2050**, demand for LNG will **continue reducing**, following the introduced policies and rapid electrification of sectors that are currently reliant on natural gas.
- **Proportion** of supplied methane based **clean gases** is estimated to represent up to 15% between chosen corridors.
- **North Africa** is expected to join Middle East, Australia and US Gulf Coast in delivering of clean gasses (**e-methane**) **towards Europe**.
- **US Gulf Coast** will continue leading in delivering e-methane and Bio-LNG considering **scale-up** of their production.
- **Australia** is following UGC in delivering of e-methane and Bio-LNG, mostly **towards Japan**, using the established infrastructure.

Table of contents

Guidehouse
outwit complexity

Value Chain Configuration Assumptions

A base case of assumptions were aligned on to produce a base set of results, which can be modified by the user to fit their understanding of technology efficiency, carbon intensity or cost.

FEEDSTOCK

- Renewables are co-located with production facility therefore no electricity losses to transmission are accounted for in the green hydrogen or e-methane production step, and CO_2 intensity is based on renewable power.
- All required feedstocks for molecule production are readily available and incur no energy losses to obtain, for example CO_2 is readily available for the production of e-methane.

PROCESS ELECTRICITY

- The proceeding processes that require electricity such as hydrogen compression, liquefaction, ammonia cracking and more draw from grid electricity in the exporting and importing country before and after transport. The carbon intensity of the respective grids is therefore used to calculate the total CO_2 emissions, which is forecasted to get cleaner over time in all geographies corresponding to the IRENA "Energy Transformation" scenario of fossil fuel reduction and renewables uptake.

- For bio-LNG and e-methane, we assume that pipeline compressors are powered with the clean fuel and as a result do not incur emissions at those steps, but final energy product is derated. Multiple value chain configurations can exist for e-methane, in which you power compressors with e-methane itself like is traditionally done with natural gas, or with outside electric power. Here we are prioritizing carbon intensity, so e-methane is used to power compressors resulting in 0 emissions at compression steps, but derating of the methane content moving through the value chain. You could instead prioritize final delivered product using electricity to power processes, but the emission intensity of your final product will be higher.

TECHNICAL ASSUMPTIONS

- Assuming average inlet pressure of H_2 liquefaction of 20 bar, so decompression energy requirement is covered in the H_2 storage step, and is considered to be negligibly different between decompression to transmission, distribution, and liquefaction pressure inlets (+/- 50 bar).

- At H_2 grid distribution level no energy requirement for compression is assumed, only leakage energy losses are accounted for at the modal change, assuming that the right pressure for distribution (~30 bar) will be obtained after ammonia cracking, H2 regassification, and H_2 pipeline transport.

- Variable losses include either boil off related losses from shipping or leakage over distance for pipeline transport.

- Time of storage and resulting boil off is not accounted for, considered to be a non-factor between gas value chains.

- We are still accounting for the warming via methane leakage effect of bio-CH_4 and e-methane because we are considering the final fuel product neutral at combustion in relation to the CO_2 that is required to make the fuel. Difference between GWP of CH_4 and CO_2 subtracted in the formula (30-1).