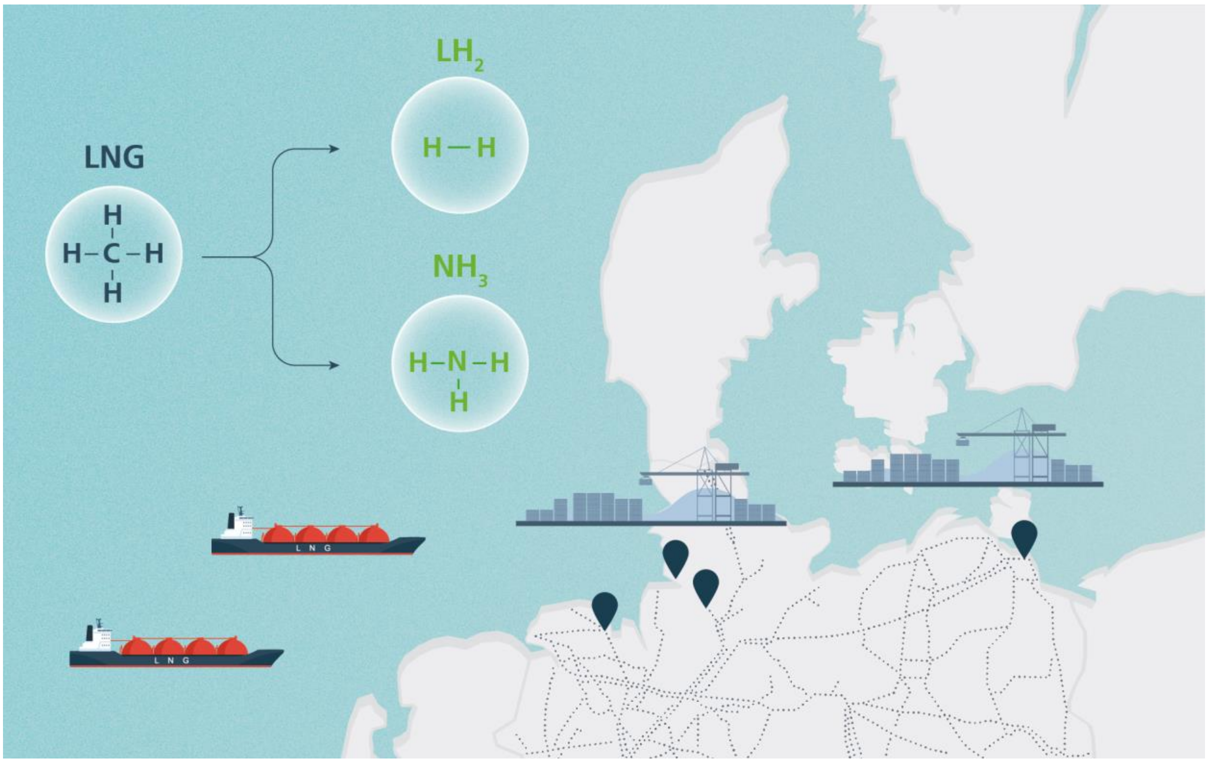

Conversion of LNG Terminals for Liquid Hydrogen or Ammonia

Analysis of Technical Feasibility under Economic Considerations

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Conversion of LNG Terminals for Liquid Hydrogen or Ammonia

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List of abbreviations

barg	Relative pressure in bar
bcm	Billion cubic meter
BOG	Boil-off gas
BOR	Boil-off rate
FSRU	Floating Storage and Regasification Unit
H_2	Gaseous hydrogen
LH_2	Liquid hydrogen
LIN	Liquid nitrogen
LNG	Liquefied natural gas
NH_3	Ammonia

1 Executive summary

Intending to reduce the German energy dependency on natural gas from Russia, the German government has signed contracts to set up several import terminals for liquefied natural gas (LNG). These include both chartered FSRUs (Floating Storage and Regasification Units) and fixed onshore terminals. LNG enables new importing routes as it can be transported via ship from countries that are not connected to Europe by pipeline. As LNG is not a climate-neutral energy carrier, the construction of new fossil fuel infrastructure, which has projected lifetimes reaching into the 2040ies, raises concerns for stranded assets and fossil fuel lock-ins. A prospective solution for using the terminals long-term is to extend their use to other potentially climate-neutral energy carriers, such as liquid hydrogen (LH_2) or liquid ammonia (NH_3). However, the extremely low temperatures of -162°C needed to liquefy natural gas impose complex technical requirements on the terminal components and materials. Likewise, the physical properties of LH_2 and NH_3 inflict their own technical challenges. The experience on technical requirements and costs for converting LNG terminals for NH_3 is still limited. For LH_2, the knowledge is even more scarce, as there is only one existing prototype liquid hydrogen terminal in Kobe, Japan, and the good is not globally traded.

This report sheds some light on the state of research on the technical feasibility of converting LNG terminals under economic considerations and identifies research gaps through a dedicated literature research complemented by a series of expert interviews with academia and industry.

The main conclusions of the analysis are the following:

Currently, it is uncertain if there is a future use case for LNG terminals with renewable energy carriers, which poses a risk for them to become stranded assets in the medium term.

- This uncertainty arises, among others, from the following factors: Future demand of the different energy carriers is still very unclear, lack of experience with the necessary technologies on a scaled, industrial level, and lack of clarity of technical knowledge whether certain components are suitable for LH_2 (risk due to material embrittlement and very low temperatures) or NH_3 (corrosive and toxic), especially concerning the choice of the steel used in LNG terminals.
- There will likely be additional investments required for LNG infrastructure (like import terminals) to be converted to climate-neutral energy carriers such as liquid hydrogen (LH_2) or ammonia (NH_3) in the future.

If a terminal conversion is planned, ammonia (NH_3) is currently seen as a likely candidate for a potential climate-neutral energy carrier that could be imported through converted LNG terminals.

- A trend to move towards NH_3 as an energy carrier in the future is currently visible through announced plans for potential conversions of LNG terminals (e.g. in Stade) as well as dedicated NH_3 terminals (e.g. in Rotterdam or Wilhelmshaven). However, this is a snapshot of current announced plans and might be subject to change.
- Compared to LH_2, NH_3 has more favourable physical properties in terms of boiling temperature and hence has lower thermal insulation requirements. However, it is toxic, which poses challenges for its handling and transportation. NH_3 road transport is heavily regulated, and there is no existing pipeline network in Germany.

- The LNG terminals storage tank makes up the largest share of the investment cost and has a long estimated lifetime. Other components, such as heat exchangers or pumps with moving parts, constitute a smaller share of the investment and are likely replaced before a conversion. If material requirements for NH_3 are considered in the design phase of the tank, it is therefore generally estimated that a significant share (approx. 70%) of the invested capex into the LNG terminal can be reused for NH_3. This concerns especially the type of steel used. Not all steels used in LNG tanks are suitable for NH_3, and many have yet to be tested for compatibility (e.g. with a high nickel content).
- Depending on which final product is needed, an NH_3 cracker might be necessary to convert it into hydrogen and nitrogen. NH_3-cracker exist today, but are not yet available on an industrial scale. Their cost and high energy consumption impact the economic feasibility of the terminal conversion.

Conversion from LNG to liquid hydrogen (LH_2) is technically challenging but feasible, however, the current lack of practical large-scale implementations does not allow drawing final conclusions.

- Using LH_2 in LNG terminals is considered to be very challenging, as its lower boiling point at a temperature of -253°C requires extensive adjustments of components' thermal insulation. However, if it is planned to regasify hydrogen shortly after the import or intend to use the boil-off gas for other use cases, keeping the boil-off rate as low as for LNG may not be necessary.
- The risk of hydrogen embrittlement in materials excludes the use of some common steels used in LNG tanks. It is strongly recommended to consider the material compatibility with LH_2 in the design phase of the LNG terminal. For example, by using high-alloy stainless steels suitable for very low temperatures (e.g. 304L or 316L). Otherwise, components like the storage tank, as the largest share of the investment, will not be compatible to LH_2.
- If LH_2-compatible steel is used in the construction of the storage tank, and a higher boil-off-rate is acceptable, around 50% of the LNG investment cost could be reused with LH_2.
- The use of thermodynamic valuable "coldness" of the LH_2 at the (import) terminal location is seen as a valuable input for possible neighbouring industry or chemical processes that can lead to significant CO_2 emission reduction. This is an especially promising potential for air separation or liquefaction plants needing cooling capacity at very low temperatures. This potential benefit has received less attention so far and should be taken into account in future considerations.

There is still a lack of experience with upscaling the majority of components needed for both NH_3 and LH_2 terminals.

- Although NH_3 has an established infrastructure due to its use in the fertilizer industry, the current scale of the existing terminals is sufficiently lower than the terminals planned for LNG. Therefore, experiences remain limited for future larger scale import terminals.
- As there was and is little to no demand for LH_2, no market exists. There is only one smaller scale import terminal in Kobe, Japan. There is no experience with larger scale components (e.g. heat exchangers, storage tanks) even for designated LH_2 infrastructure. Hence, there is also little knowledge on converting large-scale LNG import infrastructure for LH_2.

Future demand for LH_2 and NH_3 is uncertain. Reliable demand projections are necessary to guide infrastructure investments and gain more planning security.

- Although NH_3 is seen as a feasible option for a converted terminal, the volumes that will be shipped in the future are uncertain. If an NH_3 cracker is necessary because hydrogen is needed, it can impact the feasibility due to its cost and energy requirements. As the NH_3 cracker would be located at the import terminal, there is a risk that it is a location (e. g. Germany) with rather high electricity prices, resulting in high energy cost. There is also insufficient experience in upscaling NH_3 crackers to industrial scales.
- Hydrogen on the other hand is more versatile, as it can be converted into other energy carriers and will be a key feedstock input in downstream industrial processes. The major energy input for LH_2 is for its liquefaction at the exporting terminal. However, hydrogen will likely be produced in countries with a lot of renewable energies and low electricity prices that would also apply to the liquefaction energy.

The feasibility of converting LNG terminal infrastructure for alternative energy carriers depends highly on the individual characteristics of the terminal and its location and generalized conclusions applicable for all terminals cannot be drawn.

- "Secondary aspects" which are not directly linked to the terminal infrastructure itself must also be included in the considerations, e.g. Inner-German transportation after terminal, chemical plants or industrial parks in the neighbourhood of the terminal site.
  - Industrial parks or chemical plants parks nearby are a key demand centre and allow to exchange valuable waste energy flows, such as waste heat to power the terminal or use of cooling capacity from cryogenic energy carriers.
  - At the same time, the proximity of potentially hazardous sites like nuclear waste plants has to be considered with obligatory safety distances to the terminal.
- An important element is the availability of infrastructure elements to transport the energy carriers after the imports are available (e.g. a pipeline or a train connection).
  - There is currently no NH_3 pipeline network in Germany, and large-scale road transportation is not feasible due to the declaration of NH_3 as a hazardous good for transport.
  - LH_2 and H_2 are already transported via road and can be blended into the natural gas grid. Yet, this blending would cause the wasting of the scarce hydrogen. A dedicated hydrogen pipeline system (so-called hydrogen backbone) does not exist today, but plans exist.
- Some plans for onshore terminals are already branded to be eligible for alternative energy carriers in the future. However, this usually entails that several components have to be converted or exchanged and the conversion cannot be reversed easily. Bivalent terminals that can handle different energy carriers at the same time without adaptations are not feasible. Some of the terminals therefore plan with synthetic (SNG) or Bio-LNG, as this can be mixed with fossil LNG more flexibly without substantial terminal conversions.
  - However, particularly SNG is entirely hypothetical today, as carbon neutral production would require large amounts of costly direct air capture or biogenic carbon to compensate for unavoidable losses in the carbon cycle of production, transport, and consumption of the SNG.

- A conversion is not feasible for FSRUs, as these are usually chartered ships that will be returned to their owner after the renting period (in Germany, this period is currently planned to be approx. 10-15 years, with a possible reduction to 5-10 years).

Concluding remarks

- Switching between energy carriers in one terminal is not feasible without adaptations. Converting some of the terminal components for use with NH_3 and LH_2 is only seen as feasible if a concept for the conversion has been made in the construction phase of the terminal and has been taken into account in the material selection of the terminal.
- The future demand for either LH_2 or NH_3 cannot be quantified with certainty today, which poses an economic risk to the projects and raises doubts about whether any new LNG projects can reliably claim to have a future use case.
- If new import terminals are built, they should be located within a network of infrastructure that supports the imported energy carrier, including demand centres such as industry parks, sources of low-carbon energy to power the terminal and transport options for further distribution.
- Only when LNG terminals are made technically fit for conversion in their construction phase and design concepts can point to credible plans for LH_2 or NH_3 supply and end-uses, could they be considered future-proof.

2 Introduction and problem definition

The Russian attack on the Ukraine on February 24, 2022 greatly increased the European concern about energy security, due to the ongoing energy dependency of EU Member States on Russian natural gas and oil. To relieve the energy dependency, alternative energy imports are evaluated, among which are the potential imports of liquefied natural gas (LNG) from countries such as USA, Canada, or Qatar.

LNG allows to transport larger quantities also by ship, as the compressed fluid requires less volume space. Countries that are not connected to the EU by pipeline, therefore, also qualify as potential exporters. The handling of LNG requires dedicated infrastructure, consisting among other components of liquefaction plants, specialised ships, and terminals to unload, store, regasify and distribute the energy carrier. To liquefy natural gas, temperatures of -162°C are needed, which is energy-intensive and imposes complex technical requirements on used materials. LNG terminals are usually located in harbours and can already be found in a number of locations in Europe. They can either be fixed onshore terminals or so-called Floating Storage and Regasification Units (FSRU), which are ships equipped with all necessary components to store and regasify LNG and deliver it as a gaseous fuel to the distribution system onshore. Germany does not have any LNG terminals at the moment. Due to the ongoing energy crisis, the construction of several potential terminals is in discussion with different levels of progression. A detailed description of these terminal plans is provided in chapter 3. Still, due to the uncertain geopolitical circumstances, the conditions may be subject to change in the future.

However, LNG is not a climate-neutral energy carrier. Energy security measures are potentially not compatible with future climate neutrality targets. With the Paris Agreement of 2015, nations worldwide committed to reduce their greenhouse gas emissions to limit the global temperature rise to well below 2°C. In order to achieve emission reductions, fossil energy carriers such as natural gas and oil have to be phased out and replaced by energy carriers that are low in emissions. Freeing up large investment volumes to build up infrastructure for an energy carrier that is potentially only used in the short to medium term, therefore, raised concerns about stranded assets or potential fossil fuel lock-ins, if they incentivise the continued use of fossil energy carriers at the risk of not meeting climate mitigation goals.

A prospective solution to use the terminals long-term is to extend their use to other potentially climate-neutral energy carriers, such as liquid hydrogen (LH_2) or ammonia (NH_3). This prospect is held out for the currently planned LNG terminals for Germany. These alternative energy carriers have differing requirements in terms of temperature and pressure for liquefaction, suitability of materials and additional components in the terminals. A later repurposing of the LNG terminal could, therefore, be complex and expensive or even technically or economically unfeasible.

Here, a conflict of objectives arises: A fast built-up of terminals is needed if LNG should play a role in improving German and European energy security. On the other hand, considering the suitability of the terminal for a climate neutral energy system requires extensive planning and projections of future use of non-fossil energy carriers. NH_3 has been a globally traded good for decades, and there is, therefore, an extensive knowledge base on its handling, transport and storage, and a number of terminals exist. However, the experience on technical requirements and cost for converting LNG terminals for NH_3 is still limited. For LH_2, the knowledge is even more scarce, as there is only one existing liquid hydrogen prototype terminal in Japan, and the good is not globally traded. An analysis of the technical feasibility of converting LNG terminals for alternative energy carriers is, therefore, necessary to provide insights on necessary political measures in setting up a secure, affordable, clean and sustainable energy infrastructure.

3 Background: LNG terminal plans in Germany

The German government has chartered several FSRU and is planning onshore terminals in the north of Germany. The FSRU in Wilhelmshaven is planned to be the first terminal to go into operation in December 2022 (see Table 1). The FSRU in Brunsbüttel does not have an operation date yet, but it is currently planned for end of 2022 or beginning of 2023. The third FSRU is planned in Stade, the fourth one in Lubmin. The latter two terminals are planned to be ready for operation in November 2023. Next to the ships from the German government, another privately owned FSRU is planned by Deutsche Regas in Lubmin with a capacity of 3.5 bcm/year, starting deliveries end of 2022. A total of 2.94 billion Euro is made available by the German government [8, 15]. FSRUs have projected charter times of 5-10 years (until approx. 2032/2033, can be extended up to 15 years), while the onshore terminals are currently expected to be used until 2043 [9, 38].

According to these capacity projections, the pipelines in Wilhelmshaven, Brunsbüttel and Lubmin would be too small, if the capacities in the terminals were fully used [15].

For the moment, it is planned to import 3 bcm (32.5 TWh) LNG between January and March 2023 with the FSRUs in Wilhelmshaven and Brunsbüttel. This is a small fraction of the overall natural gas demand in Germany (1000 TWh in 2021) [15]. Germany imported 46 bcm of natural gas from Russia in 2021 [8].

In Wilhelmshaven, next to the LNG terminals, it is also planned to establish an import terminal for green ammonia, equipped with an ammonia cracker. This terminal would be connected to the planned hydrogen pipeline system. It is projected to import 0.3 Mt (10% of German hydrogen demand). It is planned for the second half of this decade [51].

In Stade, plans to establish an energy hub that is flexible to be used for multiple energy carriers have been initiated for the first time in 2016, according to Urban Stojan, founding partner and senior consultant at Hanseatic Energy Hub. In this location, a FSRU (end of 2023) and a fixed onshore terminal (end of 2026) are planned. The onshore terminal will be located in a hub consisting of a harbour and inland port, a railway and pipeline connection, an industrial park and other necessary infrastructure to handle different energy carriers and link them with demand centres. In a first step, LNG, synthetic LNG and bio LNG imports are planned, hydrogen-based energy carriers are envisaged for the second expansion stage [24]. In addition, the largest electrolytic hydrogen production site is located on-site (chlorine-alkali electrolysis), as stated by Urban Stojan (Hanseatic Energy Hub).

RWE plans to construct a terminal in Brunsbüttel, specifically for the import of ammonia. RWE is also involved in the construction of the LNG terminal next to it. According to a press statement by RWE, ammonia is considered the most competitive hydrogen derivative with the highest technical maturity. The project shall also serve as a role model for the conversion of the LNG infrastructure to green hydrogen or hydrogen derivatives. It is further planned to install an ammonia cracker on the site, whose product is to be transported to industrial customers via hydrogen pipelines. Investments are expected in the mid three-digit million Euro range [44].

The global storage capacity of LNG import terminals constituted 76.5 million m^3 at the end of 2021, of which 11million m^3 (14,4%) where located in Europe [23].

Table 1: Overview of construction plans for terminals in Germany (Status September 2022)

Location	Con-tractor	Operator	Terminal type	Start date	Terminal capacity (bcm)	Pipeline capacity	Cost
Wilhelms-haven I	German govern-ment	Uniper	FSRU	12/2022	5	5	Monthly cost: 4.8m $ for 10 years
Wilhelms-haven II	Private	NWO	FSRU	2023	N.d.	N.d.	N.d.
Wilhelms-haven III	Private	E.ON, TES	FSRU	2023	N.d.	N.d.	N.d.
Wilhelms-haven IV	German govern-ment		Onshore		5	N.d.	N.d.
Brunsbüttel	German govern-ment	Gasunie	FSRU	End 2022/2023	7.5	3.5-5	Monthly cost: 4.2m $ for 10 years
Brunsbüttel	Private	Gasunie	Onshore	2026	0.3 Mt NH_3	N.d.	N.d.
Stade	German govern-ment	Hanseatic Energy Hub	FSRU	End 2023	5	5	Monthly cost: 4.6m $ for 15 years
Stade	N.d.	Hanseatic Energy Hub	Onshore	End of 2026	13	N.d.	N.d.
Lubmin (German govern-ment)	German govern-ment	RWE, Stena-Power	FSRU	End 2023	5	N.d.	Monthly cost: 4.6m $ for 15 years
Lubmin (Re-gas)	Private	Deutsche ReGas	FSRU	End 2022	3.5	5	N.d.

Sources: Own compilation, based on [9, 15, 17]. N.d. = not disclosed.

4 Research questions and methodology

The objective of the study is to analyse the technical feasibility of converting LNG terminals for LH_2 and NH_3. To this end, a techno-economic analysis of LH_2 and NH_3 terminals will be carried out to create a knowledge base around which components are required and which materials need to be used. A first estimation of associated investment cost is provided.

The study aims to answer the following research question:

- Can LNG terminals (onshore and FSRU) be converted for use with LH_2 or NH_3 in the future?

To answer these questions, two sub-questions are formulated:

- Which technical transformations are necessary to convert the LNG terminals?
- Can the expected economic impact for converting the LNG terminals (conversion vs. new construction) be quantified at this stage?

To create a knowledge base on the different kinds of terminals, the study performed an extensive literature review as well as a series of expert interviews. A range of stakeholders from industry and academia was contacted. After the contacting period, semi-structured interviews were conducted (see Table 2). Some interviews took place with several interviewees jointly. In total, the expert insights of 16 interviewees are included in the report. Some of the interviewees wish to remain anonymous.

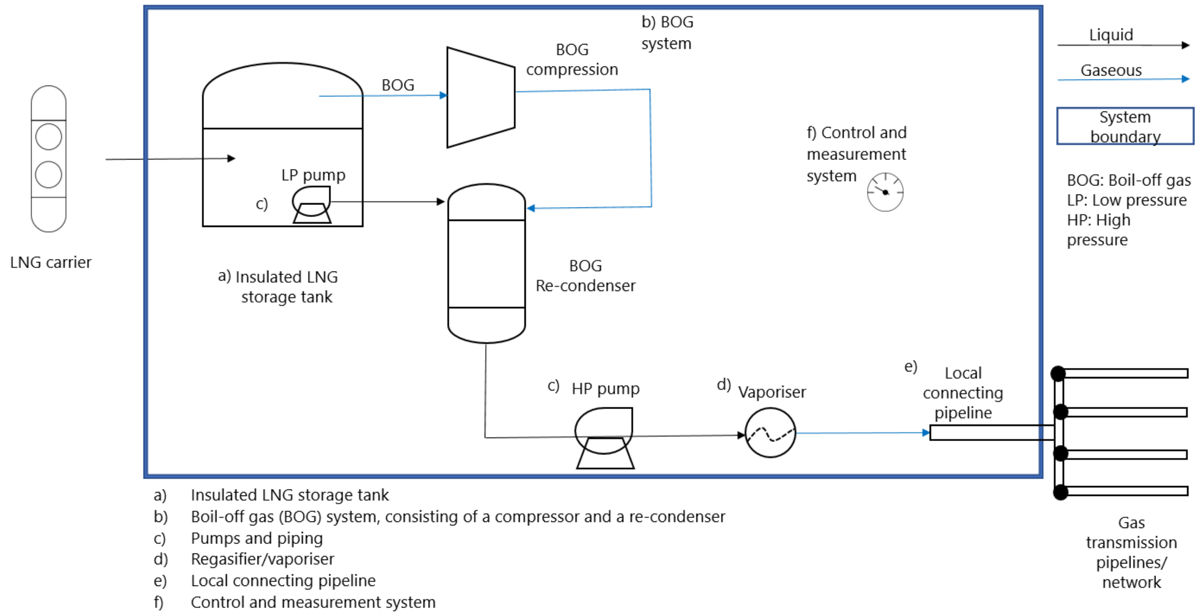
Table 2: List of interviewees for this study

Academic interviews	Industry interviews
Dr. Daniela Lindner, Head of Department Applied Hydrogen Technologies at the DRL Institute for Space Propulsion in Lampoldshausen	Jörg Schmitz, Senior Project Director, Dow and Urban Stojan, founding partner and senior consultant, Hanseatic Energy Hub GmbH
The remaining interviewees wish to remain anonymous and are referred to as academic interview 1, 2 and 3 [AI 1-3]	Dr.-Ing. Friedhelm Herzog, Senior Manager Application Technology Industry, Messer SE & Co. KGaA
	Gasunie Deutschland Transport Services GmbH
	Uniper SE
	Industrial company in the field of technical gases and plant engineering
	The remaining interviewees wish to remain anonymous and are referred to as industry interviewee 1 and 2 [II 1] and [II 2]

As discussed earlier, terminals can be either FSRU or fixed onshore terminals. The focus of the study is on onshore terminals, but inferences for FSRU are also drawn. The reason for this is that the infrastructure built onshore will have longer lifetimes and is, therefore, likely still usable in the decades where climate neutrality targets will demand the reduction of fossil fuel imports. For a consistent comparison and evaluation of the terminals, the system boundaries will be equal for all energy carriers under study. The system boundaries of this study have been set as shown in Figure 1.

The terminal consists of an insulated storage tank, a boil-off gas system including a compressor and re-condenser, high and low pressure pumps and piping, a vaporiser, a local pipeline that connects the terminal to the gas transmission grid as well as a control and measurement system. The technical components a)-f) as shown in Figure 1 will be discussed individually in the results section in chapter 6.

Figure 1: System boundary of terminals under study. Source: own compilation, based on [7]



5 Energy carriers in LNG terminals

5.1 Liquefied natural gas (LNG)

When natural gas is converted into its liquid state, it has a 600 times lower volume than in its gaseous state under atmospheric pressure. The higher energy density in liquid form allows to establish trading routes via ship. This opens the European market to other exporters such as the USA or Qatar, as it is not restricted to pipeline access. The boiling temperature of natural gas at atmospheric pressure is at a temperature of -162°C. This requires the establishment of exporting and importing facilities that maintain the cryogenic temperatures to prevent unwanted vaporisation [18].

LNG is non-toxic, not chemically reactive and odourless [21]. Its flammability range is between 5-15% volume concentration in air. Its minimum ignition energy is 0.28 mJ [41]. As LNG consists predominately of methane, the prevention of leakage is of essence, due to the high global warming impact of methane. In addition to the upstream methane emissions, natural gas produces CO_2 when combusted and is therefore not a climate-neutral energy carrier.

5.2 Liquid hydrogen (LH_2)

Hydrogen can be transported in gaseous or liquid form. Gaseous transport requires high pressurisation due to the very low density of the hydrogen gas. For transport modes with limited space availability, liquefaction is necessary. The liquefaction process is, however, energy-intensive, as the fuel has to be cooled to near absolute zero temperatures (-253°C). The energy penalty is estimated to be 30-36% of the fuel energy content. In addition, around 0.05-0.25% of the fuel boils off per day [29], which causes additional losses or increased need of reliquefaction energy. Subsequent regasification is not energy-intensive, and no further purification is needed. The technology is considered commercial, but there are no large-scale demonstration projects or existing shipping infrastructure, as no global liquid hydrogen market exists [29].

Although hydrogen has a higher gravimetric energy density than natural gas (120 MJ/kg compared to approx. 47 MJ/kg for natural gas), its low liquid density (71 kg/m^3 compared to 450 kg/m^3 for LNG) leads to a 37-42% lower volumetric energy density than LNG.

Using hydrogen instead of natural gas also necessitates additional safety precautions. The risk of an explosion or an ignition is higher for gaseous hydrogen due to its wider flammability range (4-94% by volume) and lower ignition energy (0.02 mJ). A fire caused by hydrogen would spread with almost 8 times the speed compared to natural gas. The auto-ignition temperatures for hydrogen and natural gas are on a comparable level. Hydrogen has a high reactivity and is therefore causing material degradation (hydrogen embrittlement) [39].

5.3 Ammonia (NH_3)

As a potential alternative to LNG, NH_3 is currently in discussion. NH_3 is a carbon-free fuel and can, therefore, be combusted without producing CO_2. NH_3 is currently mostly used in fertilizer production. It is thus already produced in large quantities, and a global shipping infrastructure exists. There are already 88 import ports for NH_3 worldwide. These import terminals have storage tanks and are often close to industrial plants for further processing of NH_3. [29].

NH_3 is associated with low transport losses, and its liquefaction temperature is higher than for LNG (-33°C compared to -162°C for LNG). It can also be transported in liquid form at ambient temperature by pressurizing it to 8 bar [29].

NH_3 is seen as an alternative to fossil maritime fuels, where it could be used directly in internal combustion engines, or in fuel cells or turbines. However, the operation of NH_3 in ship motors has yet to be demonstrated [29].

If hydrogen is needed, NH_3 has to be reconverted through ammonia crackers. This is a very energy-intensive process due to the high temperature requirements of 500-550°C using a catalyst or even 950-1050°C without an optimised catalyst. Between 15-33% of the energy content of the fuel are needed to provide the heat. The high temperatures make it difficult to electrify the process or to use waste heat. In addition, further purification and pressurisation of hydrogen is needed for most hydrogen applications [29]. Large scale crackers are not yet commercially available.

NH_3 has a lower volumetric energy density than LNG (11.5 GJ/m^3 compared to 23 GJ/m^3 for LNG), which entails larger storage capacity needs to deliver the same amount of energy [50]. It is, however, higher than the volumetric energy density of liquid hydrogen (8.5 GJ/m^3).

NH_3 is a toxic substance, it is corrosive and human production and use of NH_3, especially as a fertilizer, has already caused a disruption of the natural nitrogen cycle with harmful effects for flora and fauna [6]. In what way an additional use of NH_3 as an energy carrier would reinforce this effect depends on safety protocols and cautious handling. A regulatory code for further appliances of NH_3 has yet to be developed. In terms of minimum ignition energy and flammability range, NH_3 is less hazardous than hydrogen (see Table 3 in the next section).

5.4 Summary of the physical properties of LNG, LH_2 and NH_3

Table 3: Comparison of physical properties of LNG, liquid hydrogen and ammonia

Property (at 1 atm)	Unit	LNG	LH_2	NH_3
Boiling point	°C	-162	-253	-33
Liquid density at boiling point	kg/m^3	440-500	71	653-674
Higher heating value at boiling point	MJ/kg	54	142	23
Lower heating value at boiling point	MJ/kg	50	120	19
Volumetric energy density	GJ/m^3	23-24	8.5-10	11.5-17*
Heat of vaporization	kJ/kg	502-508	451	1377
Dynamic viscosity (at 20°C, gas)	mPa*s	1.1	0.88	0.99
Flammability range (gas)	%	5 to 15	4 to 75	15-28
Minimum ignition energy (gas)	mJ	0.28	0.02	380-680
Auto-ignition temperature (gas)	°C	599	560	651-1197*
Maximum laminar flame speed in air (gas)	m/s	0.374	2.933	0.07

*Stated values vary in literature.

Sources: own compilation, based on [4, 7, 16, 41].

At this point, it is challenging to estimate how the demand volumes for NH_3 or LH_2 differ from the planned LNG capacities. It is not straightforward to assume that LNG imports will be replaced by either NH_3 or LH_2 shipments of the same volume. The demand for the fuels can be quite different, as a consequence of the different application areas. Natural gas is imported into Germany for a variety of uses: building heat, industrial heat or as an industry feedstock - for example to produce

NH_3. If NH_3 was imported directly, it would likely replace some of the home production. NH_3 will, however, not replace building or industrial heat applications, but may be used in ship engines. LH_2 can, likewise, be used in the NH_3 production - omitting the step of natural gas steam reforming. LH_2 can, however, also be used in other chemical processes, as a transport fuel or in heat supply, although the latter will likely only be a viable case for high temperature industrial heat. The variety of use cases and the uncertain demand projections in the future make it challenging to infer prognoses on required capacities in the terminals, compared to the planned capacities for LNG.

6 Results - Feasibility of conversion

6.1 FSRU

Regarding the technical feasibility of the conversion, there is a substantial difference between FSRU and onshore terminals. Onshore terminals require sufficient land and sea space. Their construction time can last up to 4 years. On the other hand, FSRUs are often repurposed LNG carriers that can be leased on a short-term. Repurposing an existing carrier takes approx. 18-24 months, new FSRU may take three years to build. However, the realisation times vary between projects. They have lower upfront capital investment cost and can be relocated if necessary [22].

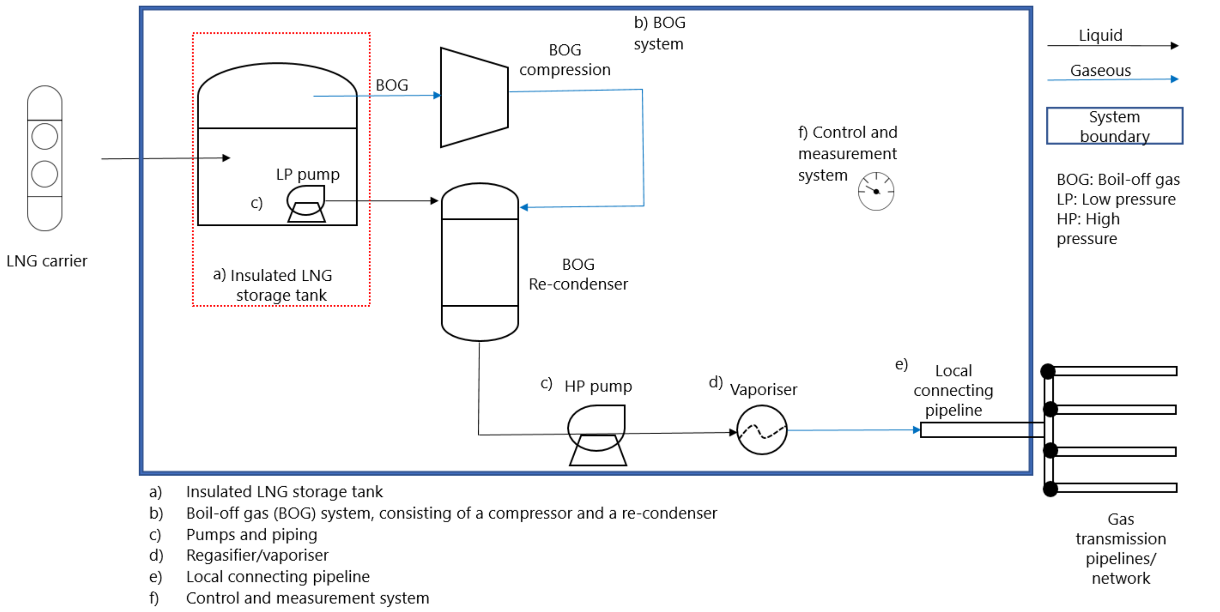
The FSRUs will be chartered for a period of time and subsequently returned to the owner. The conversion of the terminals for alternative energy carriers, therefore, only concerns the onshore terminals [9]. These will have lifetimes reaching into the 2040ies, when climate-neutrality is targeted.

In an academic interview [AI 2], it is stated that the FSRUs are a feasible interim solution for the current energy crisis, but the onshore terminals with an investment sum in the order of 2 billion Euro raise different questions about the expected investments and capacities of these terminals. Demand estimations for the future are needed.

6.2 Storage tank

6.2.1 LNG terminal

Figure 2: Location of storage tank in the LNG terminal



Once a ship has reached the harbour, large unloading structures will start to deliver LNG into storage tanks located at the terminal (Figure 2). Within one day, LNG has to be relocated from the ship to the storage tank [7]. Import terminals often have more than one storage tank, typically two to four [20]. The import terminal planned in Brunsbüttel, Germany is planned to include two storage tanks, with a 165,000 m^3 capacity each. In an academia interview [AI 2], is explained that the storage tanks in LNG terminals are not seasonal tanks, but buffer storage that can only contain the liquid for a limited time.

Two types of storage tanks are used in LNG terminals: spherical (bullet) and flat-bottom tanks. In spherical tanks, LNG is stored at 2-3 barg. This type of tank is usually used for smaller volumes and can be built over or partly underground. Underground terminals are costlier and take four to five years to build, compared to three years for over ground tanks. But they require less space and can be set up closer to cities [23, 54]. Flat-bottom tanks, on the other hand, store LNG at atmospheric pressure (below 0.5 barg) [20]. Larger volumes are usually stored in these tanks (over 200,000 m^3 capacity).

The tanks can be further differentiated into single containment, double wall (or double containment) or full containment tanks [19].

- In a single containment tank, the inner tank is typically made out of 9% nickel or stainless steel. The thermal insulation material (e.g. perlite and a glass fibre blanket) is kept in place by an outer tank made out of carbon steel. Only the inner tank material is able to keep the cryogenic conditions. For safety reasons, a containment dyke surrounds the tank and would be able to keep in the tank's liquid in the case of failure.
- In a double containment tank, an additional outer wall replaces the containment dyke. This is typically made out of post-stressed concrete and, therefore, the cost of the tank is increased. However, the space requirements are lower compared to the single containment tank.
- A full containment tank has the same features as the double containment tank, but has an additional containment by sealing the annular gap between the outer and inner tank. The second containment also is LNG tight, typically made out of pre-stressed concrete [20].

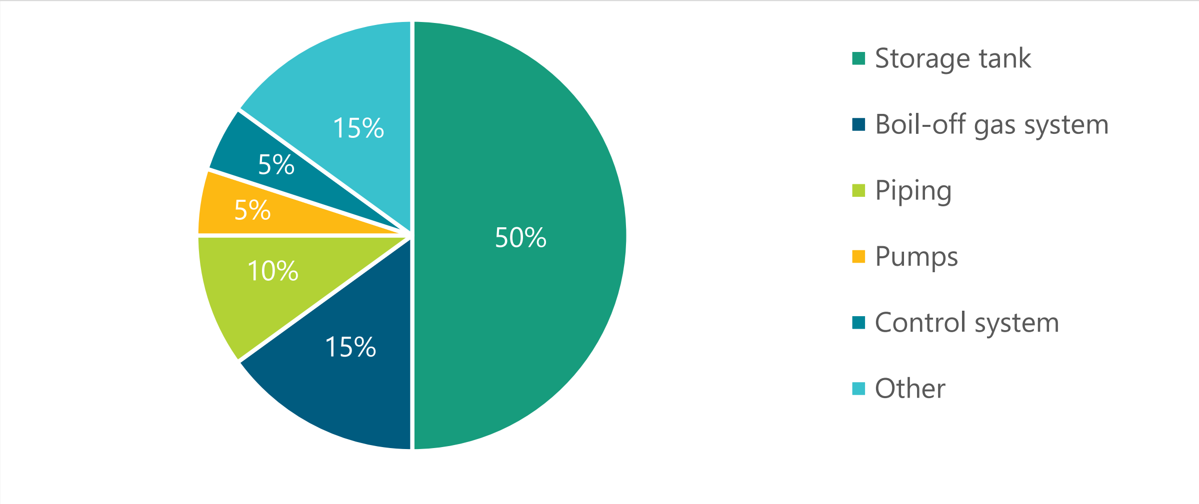
The tanks are thermally insulated to maintain the storage temperature of -162°C at all times and reduce the boil-off. The thermal insulation is usually a filling (e.g. perlite, which is a ceramic filling or glass blocks) between the inner and outer walls, as stated by Dr. Daniela Lindner, Head of Department Applied Hydrogen Technologies at the DRL Institute for Space Propulsion in Lampoldshausen. Most large LNG tanks constructed in the last 20 years were full containment tanks [20].

The main requirement for the materials used is to withstand the cryogenic temperatures required for LNG. The materials used for the tank include 9% nickel or stainless steel for the inner tank as well as the dyke, while aluminium and carbon steel are used for the additional containments [7].

Due to the not completely avoidable heat input, a fraction of the liquid fuel evaporates constantly. This boil-off is either flared out or recondensed again. For recondensation, the gas collects at the top of the storage tank and is then directed through a compressor and liquefier. The boil-off rate depends on storage pressure, thermal insulation, LNG composition and the amount of LNG left in the tank. In [7], it is stated that the boil-off has to be limited to 0.05%/day, as otherwise the losses are too high. [37] gives a BOR of 0.012 wt. %/day for a 260,000 m^3 full containment flat-bottom tank, while [1] projects 0.03-0.08 vol. %/day for normal large LNG tanks.

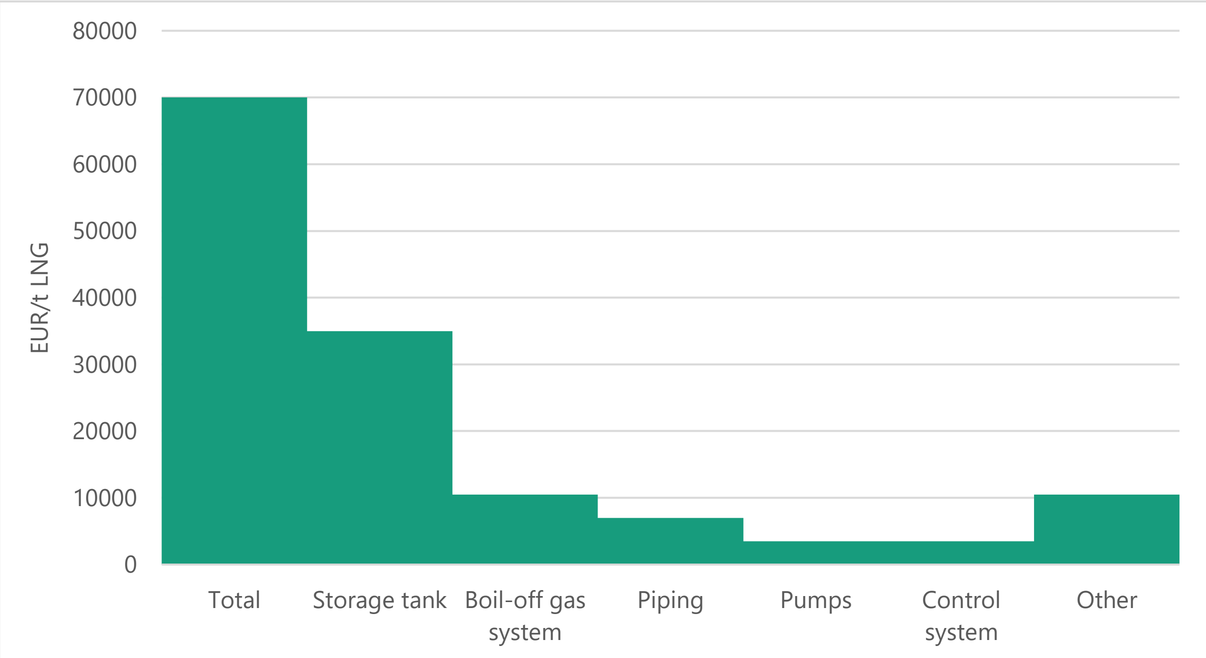
In [7], it is estimated that the tank will make up 45-50% of the total LNG import capex (Figure 3). Based on the cost share of the terminal components and the total cost of receiving terminals reported in literature, an estimation of the other terminal components can be made. This will be further discussed in the respective subsections of the terminal components.

Figure 3: **Cost share of LNG terminal components (Source: own compilation, based on [7])**



In [40], representative LNG storage tank cost are projected to lie in the range of 31-41 EUR/kg[1] for tanks exceeding 100 t capacity. Combining the mean value (35 EUR/kg) with the relative cost shares in Figure 3, an absolute cost distribution can be estimated, as shown in Figure 4.

Figure 4: **LNG terminal components cost overview, based on storage tank cost estimate by [40] and the relative cost shares of terminal components in [7]**



Also in [20], it is stated that the tanks are a capital-intensive component of the terminal, with a construction time of 32-40 months. FSRU are considered to be cheaper in capital cost, but may entail higher operating cost.

[1] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13 OCT 2022).

6.2.2 Conversion for liquid hydrogen

Only a small number of liquid hydrogen tanks exist today, and their capacity is substantially lower than for LNG. E.g., NASA has a tank with a capacity of 4,700 m^3, compared to the planned capacity for LNG in Brunsbüttel of 165,000 m^3/tank. Existing tanks are usually of smaller capacity (e.g. approx. 600 m^3), according to Dr. Lindner (DLR). They have not been scaled up yet, as there was no need for larger hydrogen tanks. Therefore, experiences with storing hydrogen in large volumes are limited. According to Dr.-Ing. Friedhelm Herzog from Messer SE & Co. KGaA (abbreviated as "Messer" from here on), a German industrial gas producer, current common tank capacities for LH_2, which are still suitable for truck transportation, are in the order of 4,500 kg LH_2 (approx. 60-70 m^3). In a terminal, of course, the storage tanks would have to be many times larger. Thermal insulation can be done with a vacuum or with liquid nitrogen (LIN) shielding, with an expected boil-off rate of 1%/d.

The ease of converting an existing LNG tank for LH_2 is viewed differently in literature and in the expert interviews. A key challenge to overcome is the diverging cooling requirements for LH_2. Regarding thermal insulation materials, some adjustments may be necessary. The risk for boil-off is much higher in the case of liquid hydrogen, due to its very low boiling temperature of -253°C. The reduction of this boil-off is a challenge [48]. To maintain the extremely low temperatures in the tank, specialised designs are needed. Existing hydrogen tanks usually have a spherical design [30] with double walls, thermally insulated with a vacuum and, potentially, an additional insulation with perlite or glass fibre [29]. According to Dr. Lindner (DLR), some liquid hydrogen tanks have perlite insulation or glass bubbles with even better insulation properties. The boil-off for LH_2 ranges between 0-0.3%/d [12, 29]. NASA was able to bring the boil-off to 0% with an additional integrated refrigeration and storage system [29]. Using non-multilayer insulation means that the boil-off rate is usually higher (1%/d), as estimated by Dr. Lindner (DLR).

The only existing LH_2 terminal in Kobe, Japan, has a spherical hydrogen tank [35]. Spherical tank designs are chosen because their design reduces the daily boil-off due to a lower heat influx [36]. It is, however, more expensive to build than flat bottom tanks. As most LNG terminals now have a flat-bottom tank, the boil-off may be higher when used with LH_2, not just because of insulation, but also because of tank design (unfavourable surface to volume ratio).

Dr. Lindner (DLR) considers the conversion to be technically and economically feasible, despite the insulation challenges.

The boil-off rate is projected to decrease with larger tank capacities (from 0.3 to 0.1%/d by expanding the tank from 300 m^3 to 2,300 m^3) due to the improving surface to volume relation [29].

It is foreseen by Dr. Lindner that with larger tanks, a perlite insulation is sufficient or acceptable, depending on the allowed BOG rate.

In an academic interview, [AI 2] it is further described that the use case of the storage tank has to be defined in the design phase: will the tank only be used for buffer storage or also as a seasonal storage? The longer the storage time, the more important becomes sufficient thermal insulation. If the removal rate of LH_2 from the tank is higher than the storage volume, the thermal insulation is less important.

If a lower boil-off rate is targeted, the LNG tank can be converted for LH_2 by adding additional (membrane) insulation panels on the inside walls with a recondenser, according to [29] and [9], Alternatively, additional insulation in the form of a second vacuum-insulated tank can be added [9]. However, no known conversions of this kind have been performed yet. Academic interviewee [AI 1], therefore, views a design for LH_2 from the beginning as a more feasible option.

In an academic interview [AI 2], it is stated that completely vacuum-free tanks are not feasible for use with LH_2. The different condensation temperatures of air components are much higher than of hydrogen, therefore, there is a risk that air condenses on the cold outside wall. Liquid oxygen can pose a high safety risk.

Next to the insulation requirements, another challenge is the employed steel in the tank walls. [9] finds that this conversion option is feasible if compatible 304L or 316L high-alloy stainless steel is used in the construction of the LNG tanks, which is confirmed by an interviewee from an industrial company in the field of technical gases and a further academic interviewee [AI 3]. The former further states that medium-alloyed steels used in LNG tanks are cheaper than high-alloyed steel. A pre-investment to ensure later hydrogen compatibility, therefore, likely increases the cost of the tank. Often, LNG tanks are built with chromium nickel steels. These are usually not tested by the manufacturer for temperatures below -200°C, according to Dr. Lindner (DLR).

Another option proposed by [29] and [9] is to only reuse the concrete hull of the tank and build in a hydrogen-compatible tank on the inside, which is considered to be costlier. Nonetheless, there are cryogenic steel tanks in use, the material challenge is therefore potentially solvable.

When heat influx increases the temperature of the gas in the tank, the pressure is elevated. For LH_2, a small temperature difference can already cause a steep increase in pressure, as LH_2 has a smaller evaporation enthalpy than LNG (see Table 3).

The economic impact of the conversion depends on whether LH_2-compatible stainless steel has been used in the LNG tank and which boil-off rate is considered to be acceptable. Economic comparisons between converted and new LH_2-tanks are difficult to draw, as there is also uncertainty about LH_2 tank cost. According to the US Department of Energy, a new, dedicated LH_2 storage tank will make up 95% of the total H_2-terminal cost [29]. IRENA compares LH_2 tank cost, which is stated to be in a range of 14-46 EUR/kg H_2. This estimate is in the range of stated LNG tank cost (30-40 EUR/kg) [29, 40]. Higher cost estimates can be caused by small tanks or spherical designs [29]. On the other hand, the US Department of Energy targets a CAPEX of below 150% of LNG tank cost for a 100,000 m^3 tank. In [40] it is estimated that the price of an LH_2 tanks will be 45-50% higher compared to LNG tanks (see Table 4).

In the interview with Messer, it is, furthermore, emphasized that only about 40% of the energy content will be stored in the LNG tank, if hydrogen is stored in it, due to the different physical properties. In academic interview [AI 3], it is further explained that, from a logistics perspective, the volumetric energy density is crucial, which is a factor of 6 smaller than LNG (71 kg/m^3 for LH2 and 450 kg/m^3 for LNG).

In any case, accepting a higher boil-off or additional thermal insulation in a repurposed LNG tank is likely not as expensive as building a new dedicated LH_2 tank. As liquid hydrogen compatible stainless steels are already used in some LNG tanks today, the economic impact of this early design consideration is seen as feasible.

Table 4: Cost estimates of hydrogen storage tanks found in literature

	IRENA [29]	DNV GL [12]	US Department of Energy [29]	NCE [40]
Cost per unit of stored LH_2	14-46 EUR/kg H_2 [a)]	24-56 EUR/kg (typical)[b)]	Below 150% of LNG tank cost	45-50% higher than LNG tanks

[a)] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13 OCT 2022).

[b)] Converted with the lower heating value of hydrogen of 33.33 kWh/kg.

6.2.3 Conversion for ammonia

Although NH_3 is already traded globally, its handling volumes are much smaller than in the case of LNG, with accordingly sized infrastructure. The largest NH_3 tank is located in China and has a capacity of 30,000-80,000 m^3, which is substantially smaller than the typical LNG tank sizes of 200,000 to 250,000 m^3, as described by Uniper SE. In another industry interview [II 2], it is stated that several tanks will be located in one terminal. In Rotterdam, a new import terminal handling NH_3 volumes of approx. 1,780.000 m^3 (1.2 Mt) by 2023 is planned [47].

The plans for the terminal in Stade are described in more detail in the interview with Urban Stojan (Hanseatic Energy Hub). The necessary adjustments for an ammonia infrastructure begin at the docking station of the carrier ship. Additional unloading arms for ammonia are planned and can be built in parallel. The location of the unloading structures has to be matched with the ships' docking stations. As these can be different for LNG and NH_3 carriers, the port needs to be designed to attend to both types of ships flexibly, according to Mr. Stojan.

The materials used in LNG tanks can potentially be used for ammonia, but there is a risk of stress-corrosion cracking. NH_3 corrodes ferrous nickel alloys and copper and zinc alloys (e.g. aluminium brass). In [50], the commonly used 9%-nickel steel for LNG tanks is considered to be unsuitable for NH_3 due to crystalline corrosion and cracks in the system. It is recommended to use special stainless steels (like 316L, 304L). Stress corrosion cracking is also found in carbon or low-alloyed steel [11]. In [7], the question is left more open, stating that nickel steel (9%), has not yet been tested for NH_3 compatibility.

Next to steel, commonly used materials for gaskets, sealing, valves and fittings are also unsuitable for NH_3, according to [50], especially when they are in direct contact with NH_3. It is recommended to use PTFE and graphite sealing and gaskets.

Next to material compatibility, it has to be considered that NH_3 has a lower volumetric density than LNG (11.5 GJ/m^3 compared to 23 GJ/m^3 for LNG). When using LNG tanks, the storage capacity of the tanks will be reduced to two thirds of their original energy capacity [7]. Due to the higher liquid density of NH_3 compared to LNG, it is heavier and the tank needs either stronger foundations or has to be used with a lower capacity [17].

Other terminal components, such as fuel pipes, would also need to be larger to supply an equivalent amount of energy [50]. Liquid density and design liquid level are necessary design parameters to calculate the static and dynamic pressures acting on the walls of the tank.

As ammonia has a higher boiling temperature and heat of vaporisation, it will have a lower boil-off rate than LNG. Thermal insulation depends on the allowed BOG rate. In the case of LNG, the insulation is typically designed to maintain the boil-off rate to less than 0.05%/day [7]. For NH_3, Jörg Schmitz, Senior Project Director at Dow in Stade, concludes that the LNG insulation will likely be overdesigned.

According to Jörg Schmitz (Dow), the tanks are the main investment of the whole terminal. In the terminal in Stade, these are intended to be designed in a modular way. It is planned to reuse existing LNG tanks with adjustments, as well as to build new NH_3 tanks, as the terminal is planned with the necessary additional spacing. The conversion is considered to be feasible, but, nonetheless, a complex technical overhaul. The focus is, therefore, first on synthetic and bio LNG, as these can be blended in the tank incrementally. The tank will already be designed with later conversions in mind. In the material selection, only a minimum amount of brass and copper is used. The thermal insulation in the existing LNG tank is considered to be sufficient. According to Jörg Schmitz (Dow), a critical element is a certification system for the terminal conversion. The certification includes, among other things, preventive measures for the operation of the tank: how it will be inspected and repaired, additional corrosion protection, etc. Metrology components, e.g. for measuring oxygen levels have to be adjusted as well. He, therefore, advocates design guidelines defined on a scientific basis, as the statements of tank manufacturers vary.

There is already some practical experience with building NH_3-ready LNG tanks. The company Torgy states to have come up with a LNG tank design that is suitable for NH_3. The tank has additional reinforcements due to the higher density of NH_3, as well as special welding requirements to avoid carbon spots. It is designed for a larger fuel flow [50].

The cost of the conversion is difficult to estimate. An analysis was carried out in [7]. The storage tank cost makes up 45-50% of the LNG terminal capex. Modification cost impact includes using a full containment tank at 63% capacity for ammonia and is estimated to be 3%, therefore making up 1-1.5% of the total LNG capex impact. Building a full containment tank "ammonia-ready" from the beginning would incur a pre-investment cost impact of 5%, leading to a total cost impact of 2-2.5% of overall LNG capex (Table 5). A conversion is therefore found to be the more economic approach in this analysis. The cost of a new NH_3 tank is lower than for LNG per kg of gas, but it has to be considered that NH_3 has a lower energy content than LNG.

Table 5: Cost estimates of ammonia storage tanks found in literature

	IRENA [29] New tank	DNV GL [12] New tank	Black and Veatch [7] modification	Black and Veatch [7] Pre-investment
Storage tank	Ranging from approx. 946 EUR/t NH_3[a)] for <10k t NH_3 to 720 EUR/t NH_3 for 60k t NH_3 storage capacity	598-1752 EUR/t NH3	1-1.5% of total LNG tank capex	2-2.5% of total LNG tank capex

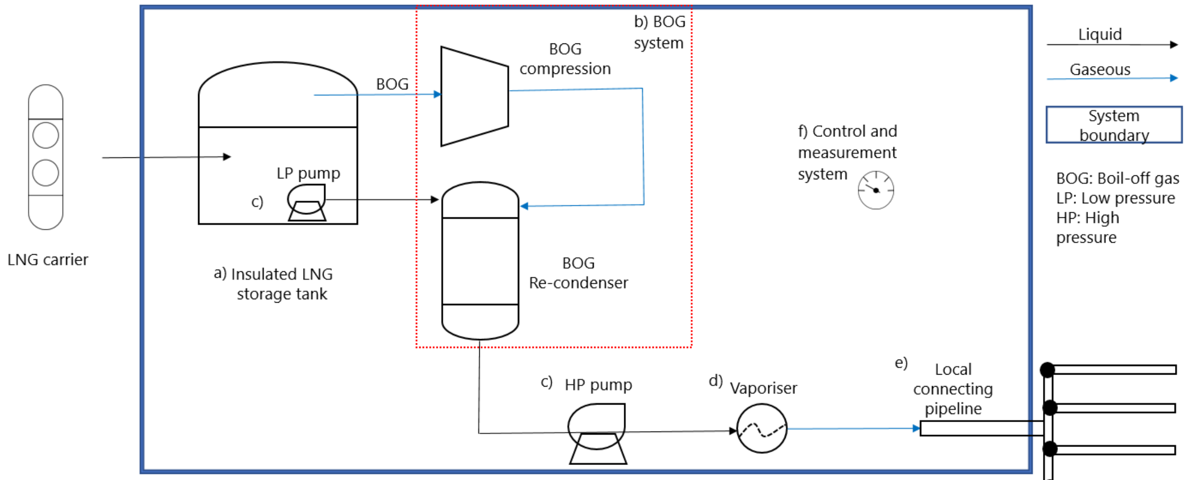
[a)] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13 OCT 2022).

[b)] Converted with the lower heating value of ammonia of 5.2 kWh/kg.

6.3 Boil-off gas (BOG) system

6.3.1 LNG terminal

Figure 5: Location of BOG system in the LNG terminal



a) Insulated LNG storage tank
b) Boil-off gas (BOG) system, consisting of a compressor and a re-condenser
c) Pumps and piping
d) Regasifier/vaporiser
e) Local connecting pipeline
f) Control and measurement system

The continued risk of liquid LNG vaporising into natural gas due to heat transfer into the tank or pressure drops requires a so-called re-liquefaction system (Figure 5). It consists of a compressor and recondenser. If the boil-off gas is not removed from the tank, the pressure will increase in the tank [19]. This is only allowed for pressurized tanks.

The boil-off gas is directed into the compressor, at near-LNG temperature at the suction. With the compression, the gas heats up. It is then brought to ambient temperature. The cooling effect causes the gas to liquefy [7].

In an academic interview [AI 2], it is explained that the recondenser also plays an important role as a phase separator (liquid/gaseous). The gas bubbles are separated from the liquid, to ensure that subsequent pumps are only working with liquid. The pump can be damaged by gas bubbles.

Reliquefaction can also be done with a cryogenic nitrogen heat exchanger, where the reliquefied LNG is returned to the tank. Another option is to use the BOG directly in a turbine or to direct it into the pipeline system. If the boil-off occurs during unloading, it can also be used to maintain pressure and temperature in the LNG tanks [19, 22, 37].

Cost estimates provided in [29] project BOG system cost of 52-103 EUR/kW[2] of installed capacity.

6.3.2 Conversion for liquid hydrogen

As mentioned before, the BOG system consists of a compressor and a recondenser. Whether compressors designed for LNG will be usable for LH_2 is viewed differently in literature and the expert interviews. On the one hand, it is seen as non-feasible by Gasunie Deutschland Transport Services GmbH (abbreviated as "Gasunie" from here on) and DLR, as the characteristics of the compressors are too different for natural gas and hydrogen. Likewise, academic interviewee [AI 1] states that,

[2] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13.10.2022).

due to the much lower boiling point of hydrogen compared to oxygen and nitrogen, the cooling concept for LNG does not work for liquid hydrogen. New compressors will likely be needed. This view is also shared by a further academic interviewee [AI 2].

On the other hand, IRENA estimates, based on [3], that compressors working with nitrogen can at least be used for the initial cooling to -190°C, and then an additional expansion and cooling system will be added for the temperatures to -253°C [29].

The pressure increase to reach the required pipeline pressure is from 1 to 80 bar (or even up to 100 bar). According to Gasunie and academic interviewee [AI 1], this will likely require several compression steps (e.g. 8-9 instead of 1-2 for natural gas), making the process technically more challenging and costlier. In [12], it is, however, mentioned that compressors working with the required cryogenic temperatures are not yet available for large capacities. This includes the refrigerant mixes in compressors, rotor designs for higher compressor speeds and other design properties requiring further research [29]. One option is to switch from piston compressors to centrifugal compressors, but these still face technological barriers such as high tip velocities.

The risk of hydrogen embrittlement requires the use of compatible materials in the heat exchangers, such as stainless steel (316L). Due to the low temperature requirements for LH_2, helium is often used as a refrigerant [49].

According to Dr. Lindner (DLR), in case of the reliquefier, the first question to evaluate is whether reliquefaction is needed at all or if hydrogen is further transported in gaseous state.

Not reliquefying hydrogen would save investment cost, as the design of the BOG system could be simplified to a compressor. In addition, the energy input necessary for reliquefaction could be saved. This energy input is stated differently in literature. According to IRENA, the reliquefaction energy input is small (0.1-0.15 kWh/kg H_2/d). Contrary, Gasunie states that BOG compression will be very capital-intensive for hydrogen, if large pressure differences have to be realised. In the interview with Messer, it is seen as a valuable alternative to not reliquefy hydrogen, but rather use the high-purity boil-off gas (purity of 8.0) directly, e.g. to run a fuel cell.

According to an academic interview [AI 2], if there is a steady-state demand for hydrogen, the BOG should always be used directly and not reliquefied. These interviewees also do not see it as feasible to operate a small-scale BOG recondenser for LH_2 in a terminal. They recommend finding use cases for the BOG (e.g. producing electricity in a fuel cell or using cooling energy, see section 6.8.1).

It is, therefore, difficult to say at this stage whether reliquefaction is advisable or not. In the only existing LH_2 terminal in Kobe, Japan, the boil-off gas is sent out together with the gaseous hydrogen coming from the vaporiser. The gaseous hydrogen is then stored under pressure. With this approach, the BOG system only consists of a BOG holder and compressor and no reliquefaction unit [33].

According to [7], the boil-off gas system makes up approx. 15% of the LNG terminal capex that can - if at all - only partly be reused in a hydrogen terminal. The cost of a new BOG system ist projected by [29] to be between 67-170 EUR/kW, compared to 52-103 EUR/kW for LNG[3].

However, moving parts in the terminal, such as the compressors, are projected to need replacement after a certain period of time (approx. 10 years) anyway, according to an interviewed industrial company in the field of technical gases.

[3] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13.10.2022).

6.3.3 Conversion for ammonia

According to Jörg Schmitz, Senior Project Director at Dow in Germany, the BOG system has to be adjusted to some extent, but a complete exchange of the component is not necessary. The main components and pipes are already designed for re-use with other gases than LNG. The adaptation of the BOG system for NH_3 is also seen as feasible by [13].

Adjustment of sealing are necessary due to the higher boiling temperature of NH_3. NH_3 has a lower boil-off rate than LNG [2]. Therefore, its reliquefaction requirements are much lower (60% of LNG capacity). It makes sense to plan the LNG terminal's BOG system in a modular way, so that the capacity sizes match with NH_3 as well [7]. Boil-off gas rates for large-scale tanks are estimated to be 0.04%/day for ammonia, consuming 0.0378 kWh/kg NH_3 of additional energy.

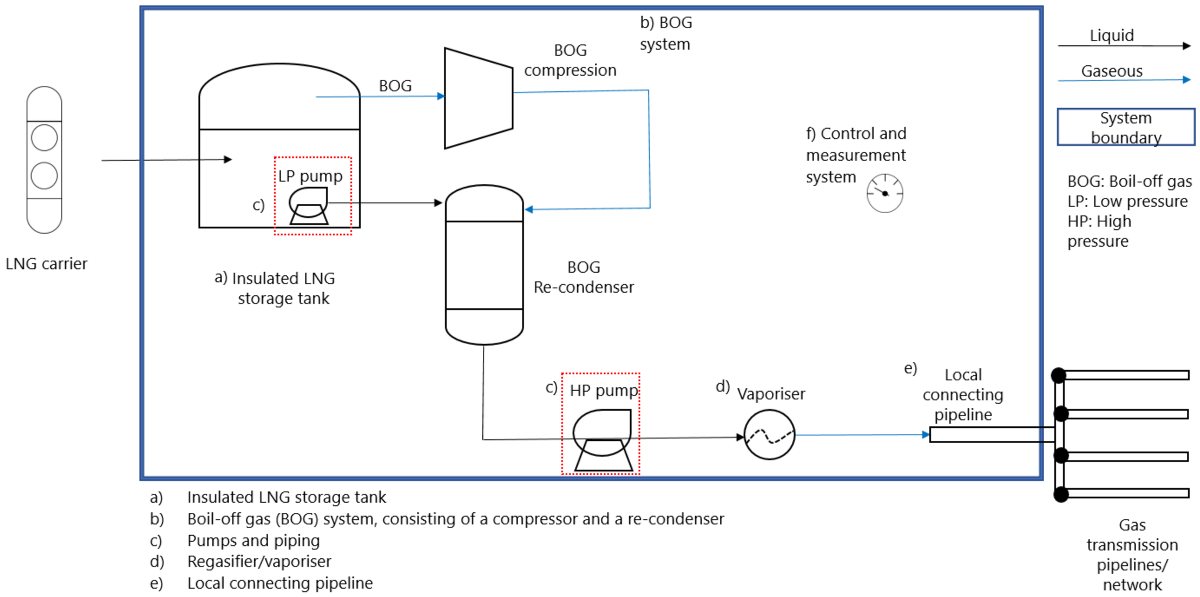
Jörg Schmitz estimates that the required conversions have a feasible economic impact compared to the overall system cost. Also in [52], found in [29], the cost of the BOG system is considered to have a small impact.

For a cost estimate, [7] assumes that two compressors (50%) are in use in the LNG terminal, making up 10-15% of overall LNG terminal cost. They estimate that a new compressor package is required, which entails modification cost and total capex impact of 5-8%. If the BOG system is built "ammonia-ready", the study assumed that three 33% compressors instead of two 50% compressors are used. This would lead to a pre-investment cost impact of 30-40%, making up overall 3-6% of LNG capex impact. In the fertilizer industry, screw compressors used for the reliquefaction of ammonia are already in use [43].

6.4 Pumping stations and piping

6.4.1 LNG terminal

Figure 6: Location of pumps in the LNG terminal



a) Insulated LNG storage tank
b) Boil-off gas (BOG) system, consisting of a compressor and a re-condenser
c) Pumps and piping
d) Regasifier/vaporiser
e) Local connecting pipeline
f) Control and measurement system

Two main pumps are used in the LNG terminal (Figure 6Figure 5). The first pump (low pressure pump) is submerged in the storage tank and pumps out LNG into the subsequent components of the terminal. The second one (high pressure pump) pumps off the liquid from the recondenser. Several other smaller pumps are located throughout the terminal.

6.4.2 Conversion for liquid hydrogen

LNG tanks require a pump inside the tank to pump the liquid out of the tank, as LNG is stored at atmospheric pressure. Whereas liquid hydrogen tanks used today usually have a positive pressure level and, therefore, potentially do not need pumps [Academic interview, AI 1].

In an academic interview [AI 2], it is estimated that the LNG pumps will all have to be replaced for hydrogen.

The properties of hydrogen are very challenging for pumps. Hydrogen has a very low viscosity, density and volumetric vaporisation enthalpy compared to methane (see Table 3). These different material properties make the reuse of the LNG pumps for liquid hydrogen very challenging, according to an academic interviewee [AI 3]. The interviewee further estimates that a different type of pumps will be used for LH_2. While for LNG typically fast-running centrifugal pumps are used, piston pumps might be more suitable for liquid hydrogen.

In addition, the risk of hydrogen embrittlement requires the use of, e.g., stainless steel (e.g. 316L). As hydrogen has a very low density, the pump flow needs to be increased to bring the volume to a comparable flow as e.g. LNG. The high-pressure pump has to be designed to be able to overcome the pressure increase necessary for the hydrogen pipeline. Hydrogen needs to be pumped to this pressure level before it reaches the regasification unit, as it would be too energy-intensive to do this with a compressor. Gasunie explains that it, therefore, depends on the required pressure level in the subsequent hydrogen pipeline.

Converting existing LNG piping is considered to not be feasible. In a recent study from Greenpeace, it is further outlined that all piping that transport liquid hydrogen requires vacuum jackets to maintain the temperature, as otherwise liquid oxygen forms on the pipe. These type of insulations are not done in LNG terminals [9]. This increases the piping costs to 5-10 times compared to LNG piping [29]. [9] projects that the complete piping system has to be exchanged and additional cooling may be needed. Currently, there are no valves and piping available for larger flows of liquid hydrogen. The problem could be circumvented with higher pressure drops and or parallel valves [29]. In an academic interview [AI 2] it is furthermore stated that the technical challenges are higher for flexible pipelines (e.g. for the unloading arms) than for static lines.

Overall, cost of piping make up 10% of LNG system cost that cannot be reused for hydrogen. The pumps are also considered to make up only a small percentage of LNG capex that would not be further used [7, 29]. In addition, pumps as components with moving parts would likely be replaced before the conversion in any case, as confirmed by an industrial company in the field of technical gases (Table 6).

Table 6: Cost estimates of LH_2 piping and pump system found in literature

	IRENA [29]	Black and Veatch [7]
Piping	14% of terminal cost other than storage tank, 10% of terminal capex	10% of terminal cost including storage tank
Pumps	4% of terminal cost other than storage tank	5% of terminal cost including storage tank

6.4.3 Conversion for ammonia

NH_3 has a higher design temperature and sealing clearance than LNG. In addition, NH_3 has a higher density than LNG. Therefore, both pumps (also the submerged pump in the tank) cannot be reused and have to be replaced by pumps with enforced pumping support [9]. Level gauges and density gauges need to be replaced or modified to the requirements of NH_3. Security equipment, such as pressure relief valves, alarm settings for leak detection and temperature gauges need to be replaced. Piping need to have double barriers [7, 50].

The pumps make up 3-5% of LNG terminal capex. In [7], it is estimated that the pumps will need to be fully replaced, leading to a modification cost impact of 1-3% of total LNG capex. This would also be the case in an "ammonia-ready" pre-investment set-up, as there is no pump suitable for both energy carriers.

The piping makes up 5-10% of LNG terminal capex. Modification cost impact is estimated to incur an LNG capex impact of 2-4%. If the piping is prepared to be "ammonia-ready" in the pre-investment, the impact is estimated to be 0.5-1% of LNG capex and, hence, cheaper than subsequent modifications (Table 7).

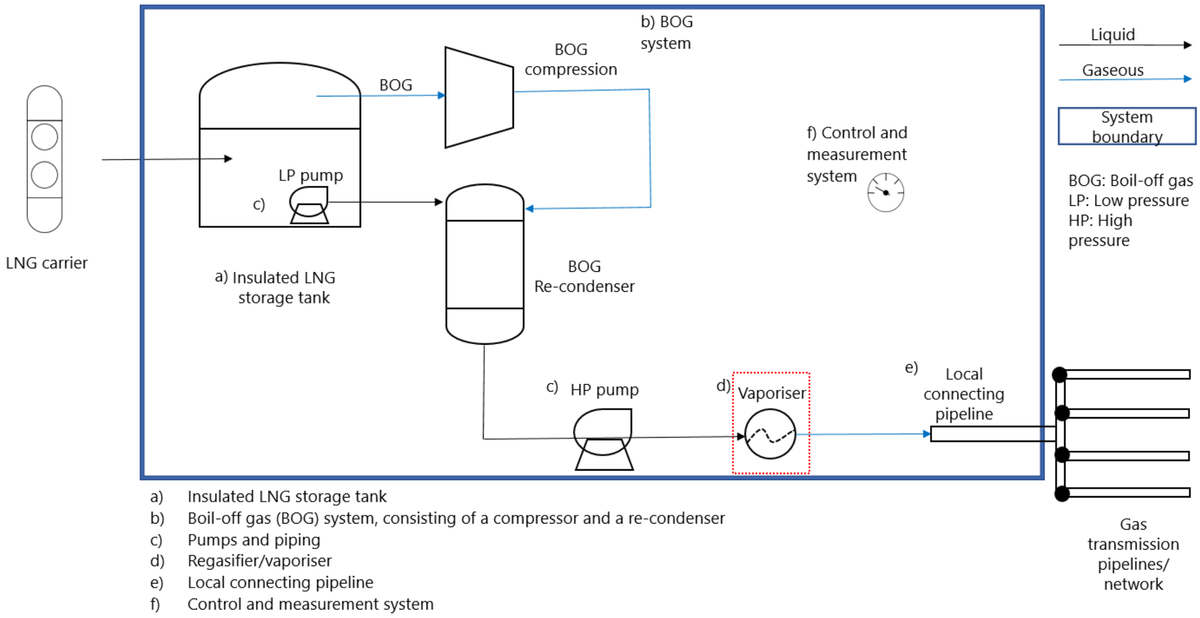
Table 7: Cost estimates of NH_3 piping and pump system found in literature

	Black and Veatch [7] modification cost	Black and Veatch [7] pre-investment cost
Pumps	1-3% of LNG terminal capex (new pump capex)	No pre-investment possible
Piping	2-4% of LNG terminal capex	0.5-1% of LNG terminal capex

6.5 Vaporiser

6.5.1 LNG terminal

Figure 7: Location of vaporizer in the LNG terminal



Before further distribution, LNG is usually regasified with a vaporiser, as it is then transported in gaseous state through a connected pipeline system (Figure 7). Several vaporiser designs exist. The most common type for LNG terminals is an open-rack vaporiser which can use sea water for heat provision [7]. Sea water is directed through tubes in the heat exchanger, which are in contact with the LNG that gets heated as a result of the temperature difference. The sea water cools down as a consequence, and is sent back to the sea. Due to the low temperature heat exchanges taking place, the tubes need to be coated with aluminium zinc alloy. The tubes are typically made of aluminium alloy. The use of sea water makes this technology comparably cheap and their simple design makes them reliable. They also have a flexible throughput capacity, which can be elementary if they are used for the vaporisation of other fuels. An example of throughput is stated to be 300 tons per hour [14].

Another type of vaporiser is an ambient air Vaporiser, working with an open loop system. Here, air is used as a heating fluid. The suitable ambient air temperature is 15° C. This type can be used where seawater is not available [14, 19].

An intermediate fluid vaporiser uses seawater in an open loop and an intermediate fluid, such as propane. In the first chamber, the intermediate fluid gets vaporized by the seawater und condensates on the LNG tubes, which vaporizes the LNG inside the tubes. The vaporized LNG enters the seawater heat-exchange chamber to be warmed up to its delivery temperature for the gaseous state. The seawater tubes are made of titanium alloy to withstand seawater corrosion. Excess cold from the heat exchange process can be used as a cold energy source. This technology also avoids the development of froth, as the first heat exchange is between LNG and the intermediate fluid. Due to the use of seawater as the main heat source, the running costs are low [14, 19].

In a submerged combustion vaporiser, LNG is heated through a heat exchanger that is embedded in a water tank. The water is heated by combustion gas from burned natural gas. This uses about 1 to 1.5% of the regasification capacity. The intermediate heating medium prevents the building of ice on the tubes [19]. Other benefits of this technology are the lower space requirement due to combustion gas utilization and the lower construction costs, since there is no requirement for water intake and discharge [14, 19].

Jörg Schmitz (Dow) states that the terminal in Stade will be incorporated into the industry park, where there is availability of low-grade waste heat that can be used for operating the regasifier/vaporiser.

The global capacity of existing regasification terminals is 994m tonnes per year (2021), of which 184 (18.5%) is located in Europe.

Regasification cost for LNG terminals is estimated to lie between 52-103 EUR/kWh[4] ([10] found in [29]).

6.5.2 Conversion for liquid hydrogen

A potential conversion of the LNG vaporizer for LH_2 depends on several aspects. From a vaporizer technology perspective, the typical LNG open-rack sea water vaporizer could also be used for hydrogen [9]. According to Dr. Lindner (DLR), air vaporizers would also be feasible. However, they require sufficient heat exchange surface area with ambient air. The use of electric heaters/vaporisers could also be an option here in the future. Electrical vaporisers are easier to control and regulate to the required volume to regasify.

It is problematic that vaporisers for LH_2 are not yet commercially available in industrial scales. Liquid hydrogen regasification technology is considered to be commercially proven in small scale application (TRL 9). For larger capacities over 1000 t H_2/d, the technology is at TRL 7 [29].

In terms of material compatibility, academic interviewee [AI 3] sees aluminium alloys as suitable.

Due to the diverging physical properties of the energy carriers, the sizing of the vaporizers differs. Similar to the recommendations for the BOG system, modular LNG vaporizer designs allow to be more flexible when dealing with alternative energy carriers, as the heat output can be better controlled [46]. According to [46], regasifying hydrogen requires less energy than for LNG (0.35 MJ/Nm^3 compared to 0.6 MJ/Nm^3 for LNG). IRENA estimates the energy consumption to lie between 0.03-1.665 kWh/kg H_2, which also includes the pumps. Waste heat from the regasifier can potentially be reused [9, 29].

IRENA states that regasification can already achieve the required pressure increase for pipeline transport, with no need for additional compressors and pumps [29].

There are already some concepts to re-use the condensation cooling, which should also be done for LH_2, as the cooling capacity potential is even larger than for LNG, emphasized by academic interviewee [AI 1]. According to an industrial company in the field of technical gases, potential applications for the available cooling capacity is to liquefy gases with higher boiling temperatures than hydrogen or to convert it to electricity using the Sterling principle.

Cost of LH_2 vaporizers is expected to decline with higher capacities. In IRENA, a study overview is provided in which the cost estimates for regasification range substantially from approx. 10 to 470 USD/kW H_2, depending on the capacity and included components [29] (Table 8).

[4] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13.10.2022).

Table 8: Cost estimates of hydrogen vaporizers found in literature

	IRENA [29]	DNV GL [12]
Vaporiser cost	10-484 EUR/kW H_2[5]	114-432 EUR/kW H_2

6.5.3 Conversion for ammonia

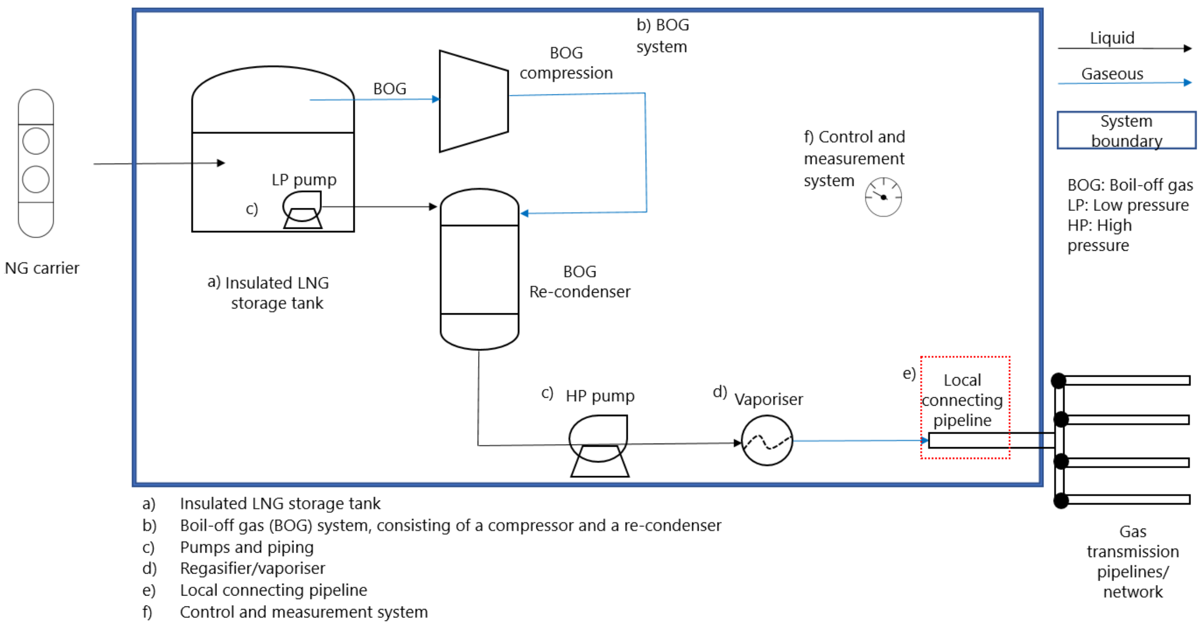
Whether a vaporizer is needed for a terminal handling NH_3 imports depends on the further use of NH_3. According to Jörg Schmitz (Dow), if NH_3 is directly transported to, e.g., industrial sites, it will most likely be transported in liquid form. To stay in liquid state, NH_3 will either have to be cooled or pressurised. In this case, there is no need for regasifying NH_3, but a further compressor is needed.

The situation is different in case of the use of a NH_3 cracker to convert ammonia to hydrogen. In this case, a vaporiser is needed to convert ammonia into its gaseous state. A potential reuse of the LNG vaporizer for NH_3 is seen as feasible by Jörg Schmitz (Dow), but its usefulness needs to be viewed in the general context of the terminal and cracker. The adaptability of the LNG vaporizer to work with NH_3 is also seen as feasible by [13].

6.6 Pipeline connection

6.6.1 LNG terminal

Figure 8: Location of local connecting pipeline in the LNG terminal



The terminal is connected to the natural gas grid with a connecting pipeline (Figure 8).

Before the LNG is guided into the connected pipeline system, its pressure is brought up to the pipeline pressure, typically with an electrical piston-compressor. The pipeline pressure can deviate based on whether low (<100 mbar), middle (100 mbar- 1 bar) or high pressure pipelines (>1 bar up to 100 bar) are in use. In a floating terminal, the gas needs to be pressurized to higher levels to

[5] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13 OCT 2022).

overcome the distance to the shoreline (up to 100 bar) [7]. In general, pressure levels of 70-80 bar or even up to 100 bar can be found in the German natural gas pipelines, described by Gasunie and DLR.

What materials are used for the pipelines depends on their operating pressure. Polyethylene variations are used for pipelines up to 4 bar, and steel pipelines are used for pressures over 16 bar [25].

6.6.2 Conversion for liquid hydrogen

Reusing existing natural gas pipelines for hydrogen requires checking the compatibility of the steel for hydrogen. Dr. Lindner (DLR) states that if it is not compatible, suitable inlayer materials can be used.

Problematic are fittings and valves, as these are usually designed for certain operating conditions, which differ between natural gas and hydrogen. Gasunie and DLR explain that the leakage rate for hydrogen has to be limited, which entails the recalibration of control valves for hydrogen mass flows. For hydrogen, helium is used to test for potential leakages. The fittings and valves are required to be "technically sealed", in which case there is no need to establish an explosion protection zone. It has also been shown that the leakage does not get significantly higher with the smaller molecule size of hydrogen compared to methane, found by Gasunie.

Gasunie further states that a key element for hydrogen-ready pipelines, is the DVGW rulebook, which will determine all technical requirements for the gas network operators. It will be adjusted for the main aspects of hydrogen-readiness. One aspect of this rulebook concerns the requirement for a fracture-mechanical inspection of the steel in hydrogen pipelines, which is not necessary for natural gas pipelines. This is necessary, as hydrogen has a 20-30 times higher crack growth. Furthermore, it needs to be considered that the lifetime of the pipelines may be shortened to 5-10 years through fluctuating demand changes (e.g. daily pressure increase up to 70 bar), emphasized by Gasunie.

The connecting pipeline in Brunsbüttel is built by Gasunie Deutschland GmbH & Co.KG and is planned to be 100% hydrogen compatible. Another critical element is the need for very clean pipelines to avoid hydrogen contamination, which can, for example, be achieved by cleaning them with dry ice, as stressed by Dr. Lindner (DLR).

Further distribution of hydrogen and its derivatives is not the focus of this study, so in this section, the topic is only addressed briefly.

Gasunie describes the status quo of hydrogen pipelines as follows: New hydrogen pipelines are already under construction. These pipelines could also be used for natural gas. To avoid hydrogen embrittlement, only high-alloy chromium nickel steel is suitable, which will make them slightly more expensive than natural gas pipelines. The pressure level in hydrogen pipelines is projected to be up to 100 bar. The new construction is considered to be much easier, as it the sealing materials will be known.

Dr. Lindner (DLR) further states that, to limit hydrogen leakage, connecting parts are welded together and checked regularly via X-ray radiation, which adds significant cost.

Similar pressure levels as in natural gas pipelines are envisaged hydrogen. Older natural gas pipelines have a pressure level of 70 bar (nominal pressure), newer ones have a level of 84 bar and high performance pipelines one of 100 bar, as stated by Gasunie. However, hydrogen has a lower volumetric energy density than natural gas (3,5 kWh/m^3 compared to 11,4 kWh/m^3 for natural gas).

In order to deliver the same capacities, the flow velocity has to be increased, as mentioned by industry interviewee [II 2]: an important design consideration is whether the pipeline will be comparably efficient (i.e. does it deliver the same amount of energy per unit of time). As gas pipelines are usually designed for the connected demands, it has to be verified if the capacity of the pipeline is sufficient.

LH_2/ H_2 is already transported via road and can be blended into the natural gas grid. Yet, this blending would cause wasting the scarce hydrogen [5].

In academic interview [AI 2], it is explained that LH_2 transport via rail and road is common practise and regulated. LH_2 allows to combine import terminals point-to-point with demand centres and can, thereby, balance the lack of hydrogen backbone into the 2040ies. It is, however, also declared as dangerous goods transport, according to an interviewee from an industrial company in the field of technical gases.

6.6.3 Conversion for ammonia

For the further distribution of the fuel, it needs to be determined if it is transported as NH_3 or transformed into hydrogen with an NH_3 cracker. As NH_3 production is a key demand for hydrogen, it could potentially make sense not to convert NH_3 back into hydrogen. However, the transport of NH_3 has substantial regulatory requirements, due to its toxicity for human health and the environment. An interviewee from an industrial company in the field of technical gases explains that road-borne transport with a lorry is not allowed, except when declared as a dangerous goods transport, where the transportation load is restricted (capacity approx. 13-57k litres [29])[6]. NH_3 is usually transported via railway with a pressure level of 12 bar in liquid form, declared as a dangerous goods transport, as described by the interviewee. According to IRENA; the capacity of these tank cars on railways is approx. 130,600 litres [29].

At the moment, no large-scale NH_3 pipeline network exists in Germany to which the local pipeline would connect to. In the future, such a pipeline system could be built, if rising NH_3 demand requires it. The current status of NH_3 pipeline networks has been analysed in [45]. Globally, these pipelines exist for the fertilizer industry, e.g., a 4,828 km long network is located in the USA, transporting 2 million tons of NH_3 per year. The European network is currently only 12 km long, with most pipelines located at harbours connected to industrial production sites (Rotterdam, Antwerp). With <35 cm, the pipeline diameter is substantially smaller than for oil and gas (up to 122 cm [29]).

In the case of Stade, the terminal is part of a large industry park, containing infrastructure such as a railway connection and an inland port. Ammonia could therefore be further transported via rail, ship or truck. The space for ammonia crackers has already been regarded in the plans for the terminals in Stade, as explained by Jörg Schmitz (Dow).

If hydrogen is needed, it has to be "cracked" out of NH_3, which is a highly capex-intensive component, according to an industrial company in the field of technical gases. This is described in detail in section 5.3. At the moment, these crackers do not exist in industrial-scale sizes, stated in an academic interview [AI 2]. However, the potential scale-up of the cracker technology in a cost-efficient manner is seen as feasible by Uniper SE. Current cost estimates range between 206-721 EUR/kW H_2.[7] In this study by IRENA [29], the potential cost reductions for crackers as a function of the plant capacity is given. The use of an NH_3 cracker, however, also requires a vaporiser, as NH_3 enters the cracker in gaseous state. Uniper SE sees a possible scenario where NH_3 is first imported and used directly, and with growing hydrogen demand, the terminal will also crack hydrogen out of NH_3.

[6] E.g. a 36 tons weight restriction exists due to highway weight restrictions [29].

[7] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13.10.2022).

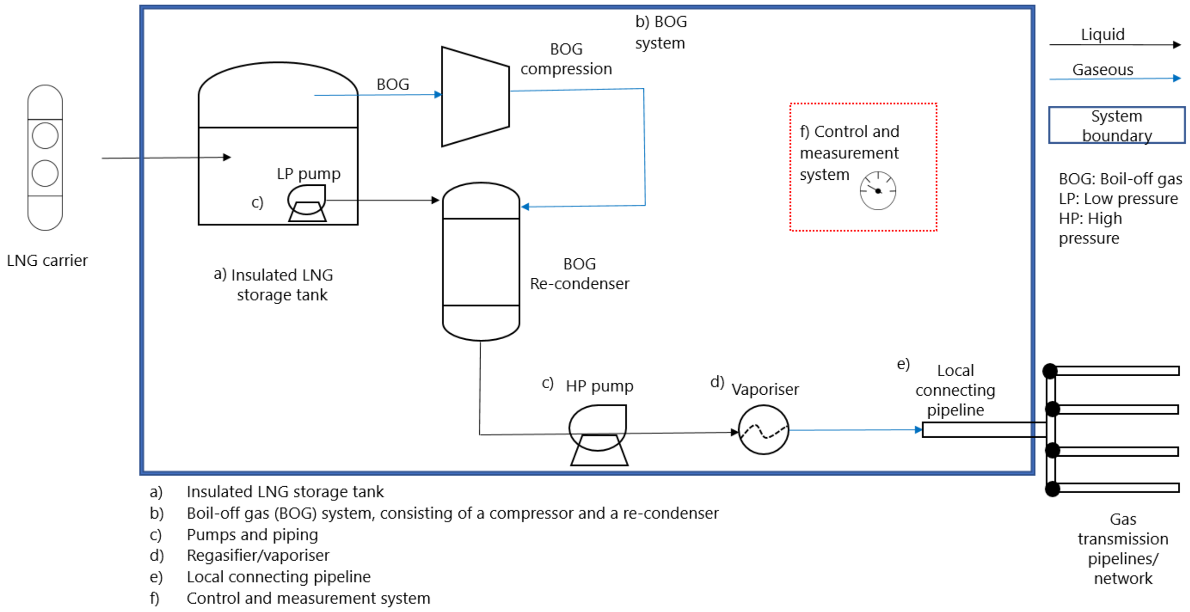
A potential scale-up of ammonia crackers to be incorporated into the terminals, therefore, depends on industrial demands.

In an academic interview [AI 2], it is emphasized that the need for ammonia cracking brings inertia into the whole process, which impacts the feasibility of certain downstream processes such as peak shaving.

6.7 Control systems and regulation

6.7.1 LNG terminal

Figure 9: The control and measurement system is located throughout the LNG terminal



The technical components of the control system (Figure 9) encompass apparatuses such as pressure safety and control valves, fire and gas detection systems, measuring devices for flow and temperature as well as metering devices.

From a regulatory point of view, a series of regulations exist for the handling of LNG. An overview is given in Table 9.

Table 9: Overview of regulatory guidelines for LNG

Guideline/code	Full name
IGC Code [27]	International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk
IGF Code [28]	International Code of Safety for Ship Using Gases or Other Low-flashpoint Fuels
ISO 20519:2021 [31]	Ships and marine technology — specification for bunkering of liquefied natural gas fuelled vessels
ISO 18683:2021 [32]	Guidelines for safety and risk assessment of LNG fuel bunkering operations

6.7.2 Conversion for liquid hydrogen

As fire and gas detection systems are designed for a specific gas, it can be inferred that all safety equipment has to be replaced for a system that is calibrated for hydrogen. The LNG fire and gas detection systems are designed for hydrocarbons, and are therefore not applicable for other fuels [7]. Hydrogen has stricter explosion prevention guidelines, due to its low ignition energy [53] (0.02 mJ compared to 0.28 mJ for methane) and a large flammability range of 4-74% by volume [41]. In comparison, methane has a flammability range of 5-15% by volume.

The European Industrial Gases Association (EIGA) document 06/19 defines the regulation for layout, location, safety distances, and other elements for LNG terminals. It can serve as an orientation for other energy carriers, but a risk analysis always needs to be done on a case by case basis, due to the varying characteristics of the terminals [40].

6.7.3 Conversion for ammonia

Most of the components of the control system designed for LNG have not yet been tested for suitability with ammonia. A conversion of the control and pressure safety valves is required, as the higher density of ammonia causes a higher pressure drop compared to LNG. As for hydrogen, ammonia-specific gas detectors need to be used. Due to the toxicity of NH_3, there are higher ventilation requirements [7]. The leak detection has to be adjusted due to the toxicity of ammonia. In addition, the higher density of NH_3 causes more mechanical stress on pipes and other components, requiring further reinforcements [9].

Modification costs include cost for control valves, fire and gas sensors, inline devices and other components [26]. According to [7] the cost of the instrument and control system makes up 3-5% of the total system cost. The modification cost impact is 70% of the initial LNG cost for this component, leading to an overall share on the LNG capex of 2-3.5%. If the terminal is planned "ammonia-ready", the pre-investment cost impact is 50%, leading to an overall LNG capex impact of 1-2%.

Due to the global trade of ammonia, regulations exist for the handling and transport of the fluid. However, there is no set of rules for the use of ammonia in converted LNG terminals, which is seen as a vital step before a successful reuse of the terminals, as emphasized by Jörg Schmitz (Dow). This concerns especially the choice of materials suitable for both LNG and NH_3.

6.8 Summary

Table 10 below summarizes how the components can be converted for use with liquid hydrogen or ammonia, based on the findings detailed in the previous sections. Determining the cost of the conversion is very challenging and depends on the individual terminal. Therefore, only some general inferences can be made at this point, depending also on some estimates from the interviewees.

In an academic interview [AI 2], the current use of language is considered to be misleading. The expression "H_2-readiness" currently does not differentiate between gaseous and liquid hydrogen. Furthermore, the downstream use case has to be clearly defined. It makes a difference whether ammonia is needed directly or whether hydrogen is needed and ammonia is only considered as an import route. According to these interviewees, it does not make sense to consider the hydrogen and ammonia pathways jointly, as both energy carriers have different use cases, and the demand depends on downstream applications.

Table 10: Technical and economic feasibility of converting LNG terminal components for liquid hydrogen and ammonia

	Liquid hydrogen		**Ammonia**	
Terminal component	Technical	Economic	Technical	Economic
Storage tank	Only if compatible high-alloy stainless steel has been used. Higher boil-off needs to be accepted or additional thermal insulation needed.	If reuse is feasible, approx. 50% of LNG capex can be recovered.	Only if compatible stainless steel has been used. Thermal insulation is overdesigned for NH_3. Modification is considered to be cheaper than "NH_3-ready" tank.	If reuse is feasible, approx. 50% of LNG capex can be recovered. Modification cost: 1-1.5%, but at lower capacity. Pre-investment cost 2-2.5% of LNG capex
Boil-off system	Uncertainty about feasibility reuse. If at all, only part of the cooling can be achieved with the LNG BOG capacity. Reliquefaction may not be reasonable.	If reuse is not feasible, approx. 15% of LNG capex cannot be recovered.	Adjustments are necessary, modular compressor design recommended due to lower pressure requirements for NH_3	Impact of conversion is estimated to be 5-8% (modification) or 3-6% (pre-investment) of LNG capex.
Pumps	Need to be exchanged.	5% of LNG terminal capex cannot be recovered	Need to be exchanged.	Replacement cost of 3-5% of LNG terminal capex
Piping	Not feasible due to higher thermal insulation requirements than for LNG.	10% of LNG terminal capex cannot be recovered.	Conversion is seen as feasible, but it is considered to be more economic to design the component NH_3-ready.	Modification cost of 2-4% or pre-investment cost of 0.5-1% of LNG terminal capex

	Liquid hydrogen		**Ammonia**	
Regasification/Vaporiser	Modular design of vaporiser simplifies the reuse; materials need to be compatible with LH_2/H_2.	No info	Not necessary if NH_3 is transported further in liquid state. If it is needed in gaseous state, reuse is feasible with modifications.	No info
Pipeline connection	Likely feasible with some adjustments.	No info	No NH_3 pipeline network in Germany, road transport is currently limited due to toxicity, railway connection in some terminals. Some terminals located near industry.	For larger scale uses of NH_3, the distribution network has to be extended.
Control system	Fittings and valves have to be fitted for H_2 from the beginning or exchanged.	Make up < 5% of LNG capex	Valves and sealing are not compatible for NH_3 and need to replaced.	Make up < 5% of LNG capex
Additional components	Not applicable	Not applicable	NH_3 cracker needed if H_2 is the final product.	Cost range 206-721 EUR/kW H_2.[8], cost reduction with higher plant capacity

6.8.1 Inferences for liquid hydrogen

The analysis showed that most of the LNG terminal components need to be replaced, and the reuse is only possible for the components that have been constructed with hydrogen compatible materials (e.g. stainless steel 316L). If H_2-compatible materials have been used in the LNG tank, and a higher boil-off is accepted, it can be inferred that approx. 50% of LNG capex can be reused. The amount of recovered LNG capex can be increased if heat exchanger components (condensers and vaporizers) are constructed with hydrogen compatible materials and in a modular way. Reliquefaction may not even be needed, if the hydrogen is further distributed directly in gaseous form. Considering hydrogen compatibility in the material selection will incur higher upfront cost, due to the higher cost of high-alloyed stainless steels.

The stances on the feasibility of the conversion differ. Chart industries claims that the cost are 50-60% lower when reusing LNG infrastructure in general [42]. If this is the case, reusing import terminal components would likely also bring economic benefits. On the other hand, [46] recommends constructing the terminals for LH_2 from the beginning, as the conversion is technically feasible, but not economical. Coherently, Fluxys, a Belgian gas grid operator, sees no business model for the conversion to LH_2, due to the economic constraints [9].

Inferences for the feasibility of conversion LNG terminals for LH_2 depend not only on the components in the terminal, but also on the role of LH_2 as an energy carrier itself. Its use in future energy system is highly debated, and stakeholders often come to different conclusions. While [34] states

[8] The values have been converted with the current exchange rate of 1 USD = 1.03 EUR (13.10.2022).

that LH_2 is a decade away from large-scale implementation, industry interviewee [II 2] declares that it does not make sense as an energy carrier from a thermodynamics perspective. Manufacturers will only invest in technology upscale if sufficient demand exists.

The uncertainty stems also from the lack of experience with scaled up LH_2 infrastructure. At the moment, the projections for technical scale-up and associated cost are based on theoretical estimations and lack practical experience.

In the interview with Messer, it is added that in the future, hydrogen will likely be produced and liquefied at locations with cheap electricity. The main energy inputs in the energy carrier, therefore, take place where energy is not expensive. In contrast, liquid organic hydrogen carriers or ammonia require a substantial amount of energy input at the import terminal, where energy is likely more expensive. Hence, it is recommended to use the comparably cheaper imported energy in a holistic way, which includes using the available cooling capacity. According to the interviewee, hydrogen has a more beneficial boil-off temperature for using the coldness compared to LNG. The LNG boil-off temperature is too low for a simple recooling for common industrial applications, as it would be too valuable. However, the boil-off temperature is too high to use it for cryogenic applications, e.g. for air separation or liquefaction. Air separation or air liquefaction are energy-intensive processes. Messer estimates that up to 90% of energy input for air liquefaction could be saved if electric refrigeration machines are replaced by the available cooling capacity from evaporated liquid hydrogen.

In academic interview [AI 2], advantages are seen in importing LH_2 directly when looking at its use cases: when LH_2 is imported, no further chemical conversions are needed between tank and pipeline. Regasification and injection into hydrogen pipelines, therefore, can be highly dynamic. The cooling energy from LH_2 can be harvested with a secondary cooling circuit that needs no further energy input. LH_2 can be further used for industry due to its high purity (N7.0 and higher), e.g. in the chemical or semiconductor industry. Other use cases of LH_2 include e.g. the parallel transport of chemical and electrical energy in cryogenic grid with supra-conducting cables or for peak shaving in the hydrogen grid, as explained by the researcher.

Safety regulations for using LH_2 as a fuel are also yet to be developed, and are likely also depending on the individual location.

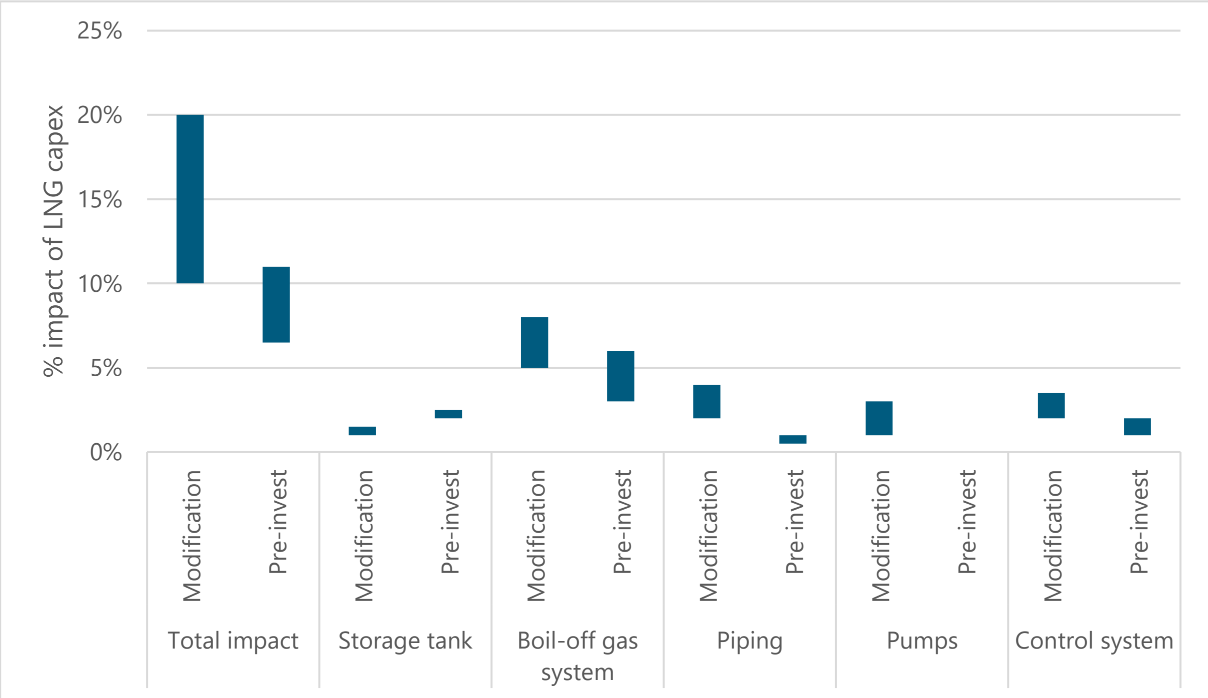
6.8.2 Inferences for ammonia

The conversion of existing LNG terminals for ammonia use is generally seen as technically feasible. The storage tank is the most capital-intensive component of the terminal, and it can be reused with some modifications. The thermal insulation of a tank designed for LNG is sufficient or even over-designed for ammonia, since temperatures are higher. As with hydrogen, material compatibility has to be regarded in the design phase of the terminal, as otherwise components may not be fit for conversion to ammonia. Based on the findings, it is recommended to use stainless steel in the construction of the storage tank, which will add cost. While some components need to be replaced (pumps, piping), their economic impact on overall terminal cost is viewed as small. For heat exchangers, modular designs in LNG terminals allow to be more flexible for other energy carriers with different boiling temperatures.

The capex impact of the conversion, measured as a percentage of overall LNG terminal capex, is estimated to be 6.5-11.5%, if considered in the construction of the terminal and 11-20% if the terminal is subsequently modified [7]. The contribution of the terminal components to the conversion cost is shown in Figure 10.

It is estimated by Urban Stojan (Hanseatic Energy Hub), that approx. 70% of LNG capex can be reused for NH_3 in the terminal in Stade. The figures cannot be compared directly without knowing the expected cost of the terminal components that cannot be reused. It has to be emphasized that the capex impacts do not include the cost of the ammonia cracker.

Figure 10: Comparison of economic impact of modifying an existing terminal vs. pre-investing to make a terminal "ammonia-ready". Source: own compilation, based on [7]



It can be seen that the capex impact is lower when conversion considerations are included in the construction phase of the terminal, compared to subsequent modifications.

In [15], it is stated that the German government answered the question on "hydrogen-readiness" with the statement that the terminals in Stade and Brunsbüttel are planned with a later switch to ammonia in mind. This includes the use of pumps, steel and boil-off systems that facilitate the conversion for ammonia. The terminal in Stade, Jörg Schmitz (Dow) sees the highest realisation probability for ammonia.

Similar to the LH_2-case, the use cases for NH_3 imports have to be analysed. It must be determined how much NH_3 will be used directly, i.e. without needing NH_3 cracking, and how much NH_3 has to be converted back to hydrogen. The demand for NH_3 is difficult to forecast. Current LNG terminals have a much larger capacity than current NH_3 terminals. According to [9], only 30 TWh of German natural gas consumption is currently used for the production of NH_3. Potential new applications as a maritime fuel can lead to higher direct usage, but the subsequent distribution infrastructure is not ready for high NH_3 volumes. If demand projections require ammonia to be converted back to hydrogen, the economic feasibility depends also on the NH_3 cracker, which is capital and energy intensive and could turn over economic benefits of the conversion. In addition, NH_3 crackers are not yet demonstrated on an industrial scale.

High uncertainty also comes from the toxicity of NH_3, which will lead to high safety protocols that have to be implemented in the terminals and will, potentially, interfere with LNG terminal set-up (e.g. in regards to safety distances). As with LH_2, many regulations are not yet available.

7 Conclusions

The study evaluated the feasibility of converting LNG import terminals for use with alternative energy carriers (NH_3 and LH_2) to prevent them from becoming stranded assets in future climate-neutral energy systems.

The following conclusions have been drawn based on the extensive analysis in this study:

- FSRUs for the short to medium term are necessary for energy security. The conversion plans only apply to onshore fixed terminals with projected lifetimes into the 2040ies.
- There is a risk that LNG infrastructure ends up as stranded assets. Switching between energy carriers in one terminal is not feasible without substantial adaptations. Bivalent terminals that can handle different energy carriers at the same time without these adaptations are not feasible. Converting some of the terminal components for use with NH_3 and LH_2 is only seen as feasible if a concept for the conversion has been made in the construction phase of the terminal and has been taken into account in the material selection of the terminal.
- The LNG terminals storage tank makes up the largest share of the investment cost and has long estimated lifetimes. If material compatibility with LH_2 and NH_3 is considered in the design phase of the tank, it is therefore generally estimated that a significant share of the invested capex into the LNG terminal can be reused.
- Next to specific material requirements, both LH_2 and NH_3 come with additional individual challenges:
  - LH_2 has an even lower boiling temperature than LNG. A higher boil-off rate, e.g. from the tank needs to be accepted, or additional thermal insulation is necessary. This also concerns other terminal components such as piping. Unlike with NH_3, there is no global market for LH_2, and there is a lack of practical experience with industrial scale LH_2 infrastructure, which leads to a high level of uncertainty.
  - NH_3 is toxic and, therefore, heavily restricted in its handling protocols (e.g. for subsequent distribution). NH_3 is not as versatile as LH_2. If the demand for NH_3 is limited, a required NH_3 cracker would add significant economic impacts to the conversion of the terminal, and they are not yet available at industrial scale.
- The feasibility of the conversion of the LNG terminal does not only depend on technical feasibility, but also on a holistic system perspective:
  - Future demand for NH_3 and LH_2 needs to be projected with more certainty. Use cases for the energy carriers need to be defined and implemented to increase investor security.
  - The proximity of industry and distribution infrastructure can lead to benefits from process integration, e.g. to use cooling capacity from the cryogenic fluids or waste heat from industrial plants.
  - The availability of distribution infrastructure elements to transport the energy carriers after the imports is vital (e.g. a pipeline or a train connection).
    The feasibility of converting LNG terminal infrastructure for alternative energy carriers, therefore, depends highly on the individual characteristics of the terminal and its location, and generalized conclusions applicable to all terminals cannot be drawn.
- Only if a later conversion to climate-neutral energy carriers is considered in the design phase, and credible plans for supply and end-uses of the energy carriers are made, can the risk of fossil fuel lock-ins be reduced.

8 Outlook

This study revealed that there is still a great extent of uncertainty regarding the continued use of LNG infrastructure with alternative energy carriers. To limit the uncertainty, the following research aspects should be addressed in the future:

- Currently, the future demand for the commodities (green) hydrogen and ammonia is still uncertain. More precise estimations will be beneficial to judge the economic feasibility of the conversion of the terminals:
  - LNG as commodity will remain limited and expensive. How long will we remain dependent on fossil natural gas and to what extent?
  - Will the demand for hydrogen only grow significantly after 2030 to 2040? Will the demand for ammonia grow strongly beyond the need for fertilizer production? What are potential use cases for the climate-neutral energy carriers?
  - Are the terminal plans in Germany overdimensioned to cover future demands? Will the capacity of the FSRUs be sufficient and the onshore terminals not necessary?
- Locations for onshore terminals should be selected based on availability of industrial sites for process integration and distribution infrastructure.
- Although the study sheds some light on the technical feasibility of the terminal conversion, there is still significant uncertainty in this field:
  - Industrial upscaling of LH_2 components as well as the NH_3 cracker has to be demonstrated. Regulatory aspects for safety - specifically if old LNG infrastructure is repurposed - is needed to provide guidelines to industry for both LH_2 and NH_3.
  - The compatibility of materials needs to be researched further in cryogenic temperature conditions.
  - The downstream use cases have to be clearly defined. The energy carriers have to be viewed in a holistic way, so that the entire stored energy (including also cooling capacity) can be used and nothing is wasted.

9 List of figures

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