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Technical Article

Techno-Economic Feasibility Study of Hydrogen Transportation in Greenland Using Pipeline and Maritime Routes

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ABSTRACT: *Greenland's abundant renewable energy resources position it as a potential producer of green hydrogen, a promising energy carrier for global decarbonization efforts. This research aims to evaluate the economic feasibility of hydrogen transportation in Greenland, focusing on compressed gas via pipelines and liquefied hydrogen via maritime routes. The study employs a comprehensive methodology that includes economic analysis of production, liquefaction, and transportation costs. This approach integrates a wide range of methods available in the literature and considers various components of the hydrogen supply chain, going beyond the typical focus on transportation strategies alone. Results indicate that pipelines are more cost-effective for shorter distances (<1,500 km) and higher demand, whereas shipping is better suited for longer distances and larger volumes. A case study of transporting hydrogen from Paamuit to Nuuk revealed that for a production capacity of 40 t/d, the cost of pipeline transport was 1.3 USD/kg, whereas for shipping it was 2.7 USD/kg. These findings contribute significantly to the development of a hydrogen economy and highlight Greenland's potential as a competitive player in the global green hydrogen market. The research provides valuable insights for decision-makers in planning efficient and economical hydrogen transportation strategies.*

1. Introduction

1.1 Green Hydrogen in Greenland

Greenland is the largest island in the world and is located between the Arctic and North Atlantic Oceans. It has the second-largest ice sheet, with only approximately 20% of the total land area of 2.17 million km^2 being ice-free (Cronhjort et al., 2015).The rising global temperatures caused by climate change are producing faster impacts in the Arctic region compared with the global average (Rantanen et al., 2022). These environmental impacts have accelerated ice melting, with Greenland's ice sheet being a primary contributor to the global sea-level rise between 2003 and 2016 (Sasgen et al., 2020).

Electricity generation in Greenland is currently dominated by hydropower. However, most communities rely on imported fossil fuels to meet their energy and electricity requirements (Arruda, 2018). The Greenland government has confirmed its commitment to energy independence by increasing the contribution of renewable energy to its energy mix (da Silva Soares, 2016). Galivoma et al. highlighted Greenland's substantial onshore and offshore wind potential. They estimated that harnessing wind energy from just 20% of the ice-free land could theoretically generate approximately 333 GW of onshore capacity. Wind energy is classified as the renewable energy source with the highest potential in Greenland (Galimova et al., 2024). However, the intermittent and unpredictable nature of renewable energy generation poses challenges to the stability and consistent availability of power to satisfy energy and electricity demands (Mlilo et al., 2021). As a result, backup and storage systems such as batteries, pumped-storage hydroelectricity, and green hydrogen must be integrated for energy storage during peak times (IEA, n.d.). Areas with an abundance of renewable energy resources and access to water sources, such as Greenland, are optimal for green hydrogen production (Maka and Mehmood, 2024).

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Green hydrogen has great potential as an energy carrier and presents a promising solution for reducing carbon emissions and transitioning to a sustainable future (Zhou et al., 2024). Currently, hydrogen has several industrial applications including ammonia and methanol production and the emerging field of steel production (IEA, 2019). Therefore, the role of hydrogen in revolutionizing the energy and transport sectors is of paramount importance (Camacho et al., 2022).

At present, the European Union consumes approximately 9.7 million tonnes (MT) of hydrogen (Bairrão et al., 2023). According to the International Energy Agency (IEA) and European Commission (2020), green hydrogen currently costs up to 6 USD/kg. This level is considered expensive and is due to the high costs of electrolysis and renewable energy. However, the cost is anticipated to decrease by up to 50% by 2030 as manufacturing technologies advance and hydrogen production and distribution scale up (Brändle et al., 2021; Hydrogen Council, 2020).

Limited data are currently available on the cost of hydrogen production in the Arctic region. A feasibility study by Chade et al. (2015) evaluated the application of wind turbines combined with a hydrogen energy storage system to support existing diesel infrastructure on Grimsey Island, Iceland. They concluded that a wind–hydrogen system offered a lower electricity cost than a diesel-only system. Although the cost of hydrogen production was not examined, a similar study focusing on green hydrogen for decarbonizing diesel-reliant electricity in Greenland evaluated the hydrogen generation costs across multiple locations. That study also analyzed the feasibility of employing a wind energy system with a green hydrogen backup to decarbonize Greenland's remote communities (Matthew et al, 2024). The resulting levelized cost of hydrogen (LCoH) ranged from 2 to 3 USD/kg, indicating the potential for producing green hydrogen at competitive costs.

1.2 Hydrogen Transmission

The hydrogen supply chain, which includes production, transmission, and distribution, is currently the subject of intensive research. Hydrogen is primarily transported using high-pressure gas in trailers, cryogenic liquid in tankers, and gas in dedicated pipeline networks (Zacarias and Nakano, 2023). It has a high gravimetric energy density, which makes it a suitable energy carrier; however, it also has low volumetric density and high reactivity, which pose some challenges to its storage and transportation (IEA, 2019). The cost of hydrogen delivery is influenced by factors such as the quantity of hydrogen to be transported (Yang and Ogden, 2007), transport distance, and form of hydrogen (e.g., ammonia).

1.2.1 Pipelines

Hydrogen pipelines offer a potential solution for high-volume, long-distance transport, and they have a lifespan of 30–80 years (IEA, 2019). This method ensures a reliable and low-loss hydrogen supply. However, the design of hydrogen pipelines requires careful consideration of material compatibility, leak prevention, and safety because of the reactive and flammable nature of hydrogen. Hydrogen embrittlement, the phenomenon in which hydrogen weakens metals, presents a significant challenge in pipeline construction (Raj et al., 2024). The dependency on a fixed route and the need to predict hydrogen production and consumption levels over a pipeline's lifespan present further complexities (Dinh et al., 2024).

Hong et al. (2021) compared various hydrogen transport methods, including those for methylcyclohexane, liquid hydrogen, compressed hydrogen, and liquid ammonia, based on their energy efficiency, carbon emissions, and costs. That study concluded that the optimal transport method depended on the specific export location and intended use. In this case, the pipeline transportation of compressed hydrogen from neighboring countries was the most cost-effective option. Similarly, a study by Solomon et al. (2024) investigated the cost-effectiveness of compressed hydrogen gas transport via gas trailers and pipelines. The study found that the optimal transport method was primarily influenced by the hydrogen demand and distance. Pipelines are advantageous in high-demand, short-distance scenarios, whereas gas trailers are more cost-effective for lower demands and shorter distances. The United States and Europe have an established network of approximately 4,600 km of dedicated hydrogen pipelines (IRENA, 2022). In contrast, the Arctic lacks hydrogen pipeline infrastructure, despite the presence of the Trans-Alaska oil pipeline (Lanan et al., 2001). Extreme Arctic conditions, including permafrost and remote nature, present challenges for pipeline construction; therefore, further design considerations and mitigation strategies for hydrogen pipelines are required (DeGeer and Nessim, 2009).

1.2.2 Liquid hydrogen tankers

Liquid-hydrogen transportation via tankers was the second method explored in this study. The existing and future development of port facilities further enhance the potential for shipping green hydrogen (Arctic Portal, n.d.). The low volumetric density of hydrogen renders it inefficient for large-scale transportation under ambient conditions (Niermann et al., 2021) but if liquefaction is employed, it can reduce the volume of hydrogen for storage and transportation. However, liquefaction is an energy-intensive process requiring cooling to −253 °C (Al-Breiki & Bicer, 2020), resulting in approximately one-third energy loss.

Liquid hydrogen has high specific energy consumption (SEC), low exergy efficiency, high total expenses, and boil-off gas (BOG) losses, which hinder its widespread use as an energy carrier (Ghorbani et al., 2023). However, various types of liquefaction cycles can be used depending on the specific requirements of the liquefaction process, its scale, efficiency, and type of liquefied gas (Lee et al., 2022). Although many studies have focused on hydrogen liquefaction cycles and methods to reduce SEC, studies tailored to Arctic conditions are not available, even though cold climate conditions may offer significant advantages by reducing the energy consumption for liquefaction and minimizing BOG losses.

At present, shipbuilding for liquid hydrogen transportation is a nascent field with no shipping trade. Only one liquid hydrogen tanker, the SUISO Frontier (Kawasaki Heavy Industries, 2019) has been constructed in Japan as a proof-of-concept, which has a volume of 1,250 m^3. Niermann et al. comprehensively compared the cost of transporting hydrogen from Algeria to Germany via pipelines, high-voltage direct current (HVDC) electricity transmission, and shipping (both as liquid hydrogen and hydrogen carriers). The results showed that hydrogen carriers, specifically liquid organic hydrogen carriers (LOHCs), are more economical for distances exceeding 3,000 km and pipeline transport is generally preferred for distances less than 3,000 km (Niermann et al., 2021). Kamiya et al. supply chain analysis estimated the cost of transporting liquid hydrogen from Australia to Japan by ship to be 0.67 USD/kg (Kamiya et al., 2015). Ishimoto et al. reviewed the energy efficiency, carbon footprint, and cost of shipping liquid hydrogen (LH2) and ammonia from Northern Norway to Rotterdam and Japan (Ishimoto et al., 2020). They found similar supply chain costs for shipping LH2 and ammonia to Japan, although LH2 offered lower costs and had a smaller environmental impact than ammonia on the Rotterdam route. One of the few studies related to Arctic shipping was conducted by Dai et al. (2021), who compared the feasibility of transporting liquid natural gas (LNG) via the Northern Sea Route (NSR) with the traditional Suez Canal Route (SCR) (Dai et al., 2021). A critical gap is the absence of open-source models capable of estimating the cost of shipping for unique routes, while simultaneously considering the entire hydrogen supply chain.

Existing research has analyzed hydrogen transportation costs using pipelines and shipping; however, a unified methodology that encompasses the entire green hydrogen supply chain for green hydrogen production and transportation is limited. Therefore, this study aims to address the significant gap in green hydrogen supply chain analysis by developing a comprehensive methodology that combines procedures from a wide range of sources and integrates production, liquefaction, and transportation costs for both pipelines and shipping into a single framework. Although existing studies have focused on specific aspects of hydrogen transportation, a standardized approach for determining costs across diverse locations is lacking. By applying this unified methodology to Greenland as a case study, we conducted a techno-economic analysis to compare the viability and cost-effectiveness of hydrogen transportation methods under the Arctic region's unique geographical and environmental conditions. This approach seeks to provide a more holistic understanding of green hydrogen supply chains and offers valuable insights for decision making in the emerging hydrogen economy.

2. Methodology

2.1 Production

Green hydrogen is produced through an electrolysis process powered by renewable energy sources, such as solar and wind (Hassan et al., 2024). The cost of green hydrogen was obtained using HOMER software. HOMER is a versatile microgrid design tool that can be used to design and optimize energy systems. Its financial and sensitivity analysis tools provide the most optimized configuration based on the lowest cost factors, such as capital expenditure, operating expenses, and net present cost (NPC) (UL Solutions, n.d.). A standard system with a wind turbine, an electrolyzer, and a hydrogen tank was simulated for green hydrogen production, as presented in Fig. 1 and Table 1. A hydrogen load of 40 t/d was used to standardize the values, ensuring consistent and comparable results when calculating the liquefaction costs and other associated parameters. The location was selected based on a previous feasibility study (Matthew et al, 2024), which showed that Paamuit is one of the best locations for green hydrogen production. This methodology was scaled-up to analyze the cost and quantity of hydrogen generated.

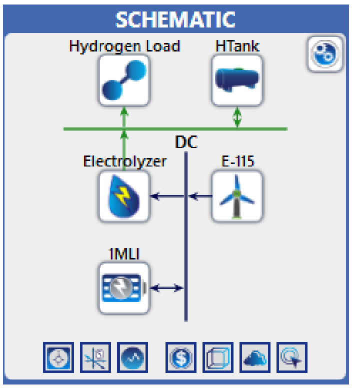

Fig. 1 HOMER schematic layout design for green hydrogen production using a wind turbine and electrolyzer

Table 1 HOMER input data specified for green hydrogen production

System Components	Input data
Location	Paamuit
Hydrogen load	40,000 kg/d
Electrolyzer capacity	HOMER optimized
Wind turbine	3 MW Enercon

2.2 Transportation

The levelized cost of transportation (LCoT) was evaluated according to Eq. (1) for the two transportation methods. Capital expenditure (CAPEX) and operating cost (OPEX) are capital and operating expenditures, respectively, given at present value in USD. Delivered H2 is the yearly hydrogen produced and delivered in kilograms, drate is the discount rate, and L is the plant's lifetime in years. The boundary conditions in this study for liquid hydrogen transmission using a liquefied hydrogen tanker include the liquefaction of hydrogen, intermediate storage at the loading and receiving terminals, and shipping, with the economic assumptions specified in Table 2.

A GIS-based scenario study by Baufumé et al. (2013) developed a detailed model for planning and optimizing a hydrogen pipeline network across Germany; therefore, the model was employed to

Table 2 Economic assessment assumptions (IEA, 2019; Dinh et al., 2024; Johnston et al., 2022)

Parameters	Pipeline	LH_2 shipping
Discount rate	8%	5%
Lifetime	30 years	20 years
Exchange rates	1 USD = 1.09 EUR	N/A

conduct a preliminary pipeline cost feasibility assessment.

An open-source model created by (Johnston et al., 2022) provided a comprehensive analysis of the shipping transportation costs of hydrogen and its carriers. These included LH2, ammonia, methanol, LNG, and LOHC (TOL/MCH). Upstream costs, including hydrogen production, intermediate transportation to the conversion site, liquefaction or conversion to a hydrogen carrier, dehydrogenation (incorporating hydrogen purification losses), and distribution costs, were not considered in the study. They only considered intermediate storage in the form of tank storage, which was assumed to be located at both the exporting and receiving ports, eliminating the distribution costs between the ship and storage. The model's global applicability and open-source nature allow the inclusion of a wide range of assumptions regarding any shipping route. This flexibility enabled the investigation of hydrogen transportation costs in the Arctic using the open-source model developed in that study. These include storage at the loading terminal, maritime transport, and storage at the receiving terminal. The costs associated with both scenarios are detailed in the following sections.

$$\mathrm{LCoT} = \frac{\mathrm{CAPEX} + \Sigma_{l=0}^{L}\left(\frac{\mathrm{OPEX}}{(1+\mathrm{drate})^{l}}\right)}{\Sigma_{l=0}^{L}\left(\frac{\mathrm{Deivered}_{H2}}{(1+\mathrm{drate})^{l}}\right)} \tag{1}$$

2.2.1 Pipeline

A simplified capital cost model was used for the pipeline system that considered the major aspects of pipeline construction, piping, materials, and compressors. The reference model proposed two pipeline CAPEX variants in Eqs. (2) and (3) for distribution and transmission, respectively (Baufumé et al., 2013). CAPEX was expressed as a second-order polynomial function of the diameter.

The recompression cost reflects the difference between Eqs. (2) and (3). Eq. (3) includes the recompression cost, which was factored into the calculations used in this study. An offshore pipeline was assumed according to the Northstar Arctic pipeline design (Lanan et al., 2001) which has a pipe diameter of 200 mm, operating pressure of 10.2 MPa, and operating safety factor of 1.6. The cost of an offshore pipeline can be estimated based on the onshore pipeline cost multiplied by two, according to IRENA (2022).

$$\mathrm{CAPEXpipe}(D) = 2\times(3{,}400{,}000.Dpipe^{2} + 598{,}600.Dpipe + 329{,}000) \tag{2}$$

$$\mathrm{CAPEXpipe}(D) = 2\times(4{,}000{,}000.Dpipe^{2} + 598{,}600.Dpipe + 329{,}000) \tag{3}$$

The capital expenditure for the pipeline (CAPEXpipe) in Eqs. (2) and (3) is given in €/km but is converted to USD/km (1 USD = 1.09 EUR), and *Dpipe* is the pipeline diameter in meters (m). The diameter of a pipeline is a major driver of the cost of pipeline transportation systems. A sensitivity analysis of different pipeline diameters (D) was performed, and the minimum diameter used is 100 mm. The OPEX, which refers to the cost associated with energy, maintenance, repairs and labor, is inherently uncertain and requires careful consideration for accurate estimation. It typically accounts for approximately 2%–10% of the total costs (Molnar, 2022). The OPEX for the pipeline (OPEXpipe) was estimated to be 2% of the CAPEXpipe used in this study based on the recommendations of Dinh et al. (2024).

The hydrogen pipeline was assumed to operate at 10 MPa. Because hydrogen is typically produced at low pressures ranging from 2 to 3 MPa, an initial compression is necessary prior to transportation. Subsequent compression along the pipeline is required when the pressure drops to approximately 50% of its initial value (Solomon et al., 2024). According to the literature (Solomon et al., 2024), the Dracy–Weisbach equation was used to calculate the pressure drop within the pipeline in order to determine the necessary number of compressor stations required and their exact distance along the entire pipeline length. Solomon et al. (2024) calculated that the average distance the gas requires for recompression is 250–300 km.

2.2.2 Liquid hydrogen tanker

The LCoT via shipping was calculated by adjusting the CAPEX and OPEX for liquefaction, shipping, and storage to the present value. The OPEX, which includes labor costs, port charges, maintenance, and miscellaneous expenses, is estimated based on the CAPEX. This is primarily due to the uncertainties arising from the lack of infrastructure and operational data in remote Arctic regions.

BOG is inevitably generated during the storage and transportation of liquefied hydrogen due to heat ingress. In this study, the BOG rate was kept low to the required quantity for propulsion owing to the high-performance insulation technology used, as in the case presented by Ishimoto et al. (2020).

(1) Liquefaction

The cost of the liquefaction plant was estimated based on a hydrogen delivery scenario analysis model (Connelly et al. 2019). The mathematical model provided an estimate of the capital costs associated with hydrogen liquefaction. The capital costs were calculated using Eq. (4), where N is the number of liquefiers required with a given capacity (200 t/d) for each liquefier, C is the liquefier capacity in t/d, and I is the chemical plant cost index (I = 1.16 for the cost estimated in USD). This model represents the capital cost relative to the liquefaction capacity. It does not consider the energy cost of liquefaction, site operating costs, or environmental considerations. A liquefier capacity of 10 t/d was assumed.

$$\text{liquifier cost} = 5{,}600{,}000 \times N \times I \times C^{0.8} \tag{4}$$

(2) Storage

Operational expenses were estimated as a simple percentage (4% of *CAPEX*) to simplify the cost owing to wide uncertainties. Calculation of the storage capital costs determined by Eq. (5) relies on the reference values and a capacity scaling of 1.2, which requires further analysis for precision. From Eq. (5), $C0$ is the reference cost, Sx is the nominal storage capacity (which is twice the ship capacity), $S0$ is the reference storage capacity, and sc is the scale coefficient. These assumptions are presented in Table 3.

$$\text{Storage capital cost} = C0(Sx/S0)^{sc} \tag{5}$$

(3) Shipping

Maritime transportation of LH2 considers the CAPEX for the shipping tanker and OPEX, encompassing labor costs, port charges, maintenance costs, miscellaneous costs, insurance, fuel costs, and BOG costs. These were all factored in and aligned with the methodology used in the open model (Johnston et al., 2022). In this study, the ship's CAPEX was specified according to the literature value of 1,355 USD/volume capacity (Al-Breiki and Bicer, 2020). However, owing to the use of hydrogen fuel for the ship engine, the model accounts for a 10% increase in the capital cost.

The daily fuel consumption in tonnes was initially calculated to determine the fuel cost when utilizing boil-off hydrogen for propulsion purposes. Using Eqs. (6) and (7), the fuel cost was calculated, where *MP* is the market price and *LHV* is the lower heating value for LH2. Given a ship's engine capacity of 30.5 MW and an assumed efficiency of 50%, the estimated fuel consumption was calculated to be 44 t/d. (Heuser et al., 2019; Raab et al., 2021).

$$\text{Fuel cost}(\$/\text{yr}) = \text{Required fuel}(\text{t}) \times LHV(\text{GJ}) \times \text{LH2}\,MP(\$/\text{GJ}) \tag{6}$$

$$\text{Required fuel}(t) = \text{fuel consumption}(\text{t/d}) \times \text{Annual sailing days} \tag{7}$$

The storage BOG cost and shipping BOG cost were calculated using Eqs. (8) and (9), respectively. Given the inherent uncertainties and extreme operating conditions in Greenland, a 20% OPEX estimate was adopted relative to the CAPEX as a preliminary approximation. This is due to the region's unique geographical and environmental challenges, which may cause increased maintenance and operating conditions. These uncertainties and fluctuations require more precise OPEX calculations using region-specific data and in-depth analysis. Tables 3 and 4 present details of the shipping parameters used in this study.

$$\text{Storage BOG cost} = \text{Storage BOG\%} \times \frac{\text{storage capacity(kg)}}{2} \times 365 \times LHV(\text{GJ}) \times \text{LH2}\ MP\left(\frac{\$}{\text{GJ}}\right) \tag{8}$$

$$\text{Shipping BOG cost} = \text{Annual sailing days} \times \text{shipping BOG\%} \times \text{ship capcity(kg)} \times LHV\ (\text{GJ}) \times \text{LH2}\ MP\left(\frac{\$}{\text{GJ}}\right) \tag{9}$$

The annual delivered hydrogen quantity depends on the ship's annual trips, number of sailing days between the two terminals, and its capacity. This relates the distance between the production and demand to the quantity delivered, as shown in Eqs. (10)–(12). The ship was assumed to operate for 350 d at 9.23 m/s.

$$\text{Annual delivered hydrogen(kg)} = \text{Annual Trips} \times \text{ship capacity (kg)} \tag{10}$$

$$\text{Annual Trips} = \frac{\text{days in operation}}{\text{total sailing time}} \tag{11}$$

The total sailing time (d) considers the travel distance between the export and import terminals (back and forth) and the number of days spent loading and unloading at both terminals.

$$\text{Total sailing time (d)} = \left(\frac{\text{distance}}{\text{speed}*24}\right) \times 2 + \text{Terminal days} \times 2 \tag{12}$$

The annual CAPEX for the tanker and storage was calculated by multiplying the capital recovery factor (CRF), given by Eq. (13). The interest rate i, is 5% and the lifetime N is 20 years, as listed in Table 2.

Table 3 Liquid hydrogen shipping and storage assumptions[1)]

Parameters	Units	Values
Ship capital cost	\$ Million USD	237.6
Ship capacity	m^3	160,000
Storage tank capacity cost	\$ Million USD	106.03
Reference capacity	m^3	100,000
Ship lower heating value	MJ/kg	120
Fuel consumption	Tonnes/day (t/d)	44
Transportation BOG	%day	0.2
Storage BOG	%day	0.1
Lower heating value	MJ/kg	120
LH2 Market price	\$/GJ	12

[1)] Reference values obtained from Al-Breiki and Bicer (2020), Ishimoto et al. (2020), Johnston et al. (2022), and Kamiya et al. (2015)

Table 4 Liquid hydrogen shipping parameters[1)]

Parameters	unit	value
Hydrogen density	kg/m^3	71
Load/unloading	d	1.5
Operating days	d	350
Ship speed	m/s	9.26

[1)] Reference values obtained from Al-Breiki and Bicer (2020), Ishimoto et al. (2020), Johnston et al. (2022), and Kamiya et al. (2015)

$$\mathrm{CRF} = \frac{(i* \ (1+i)^N}{((1+i)^N - 1)} \tag{13}$$

$$\mathrm{CAPEX} = \mathrm{CRF} \times \mathrm{ship\,capital\,cost} + \mathrm{CRF} \times \mathrm{storage\,capital\,cost} \tag{14}$$

The LCoT can be determined by summing the individual contributions of all CAPEX and OPEX components. The LCoT comprises capital costs for the ship and storage and operating costs for the ship, storage, fuel, and BOG from both shipping and storage.

3. Results and Discussion

The methodology presented above was analyzed for green hydrogen production from a predicted wind turbine farm installed in Paamuit, Greenland.

3.1 Production: Case Study Nuuk - Paamuit

The cost of producing green hydrogen in Paamuit using wind energy and an electrolyzer was investigated using HOMER for a 40,000 kg/d hydrogen load. A sensitivity analysis was conducted on the hydrogen tank capacity, and the electrolyzer capacity was optimized using HOMER. Table 5 presents the optimized results. This includes the LCoH, CAPEX, OPEX, electrolyzer capacity, and annual hydrogen production (kg/y) for the specified system configuration. The Hydrogen Council (IRENA, 2022) reported a green hydrogen LCoH range of 2.5 USD/kg to 6 USD/kg. The simulation results aligned with this range, yielding an LCoH of 2.78 USD/kg, verifying the outcomes of the HOMER simulation.

3.2 Transportation: Case Study Nuuk - Paamuit

3.2.1 Pipeline

A cost analysis of hydrogen transportation via pipeline was conducted using Eqs. (2) and (3) to calculate the LCoT. For a medium-scale demand of 10 t/d using a pipeline with a diameter of 100 mm over 200 km, the LCoT was 4.1 USD/kg. When scaled to 1000 t/d, the LCoT decreased significantly to 0.04 USD/kg. A sensitivity analysis comparing pipeline diameters of 100, 200, and 300 mm for both 10 and 1,000 t/d capacities across three different distances is illustrated in Figs. 2 and 3.

A comparison of the two cases demonstrates that the transportation costs increase with both distance and pipe diameter. This is attributable to the direct proportionality of the material, labor, and compression costs to the pipe diameter and length. The recompression costs contributed to a 62% increase in the LCoT over 500 km. The flow rate is another significant cost driver for pipeline transportation. The results show that a higher cost is obtained for low flow rates and long distances, whereas lower costs are associated with shorter distances and high flow rates (see Fig. 3). The transmission of higher

Table 5 HOMER optimization results

Location	LCoH	Net present cost (NPC)	OPEX	CAPEX	Turbines	Capacity	Total production
Paamiut	2.8 USD/kg	\$527M	\$15.4M	\$328M	102	3 MW	14,642,420 kg

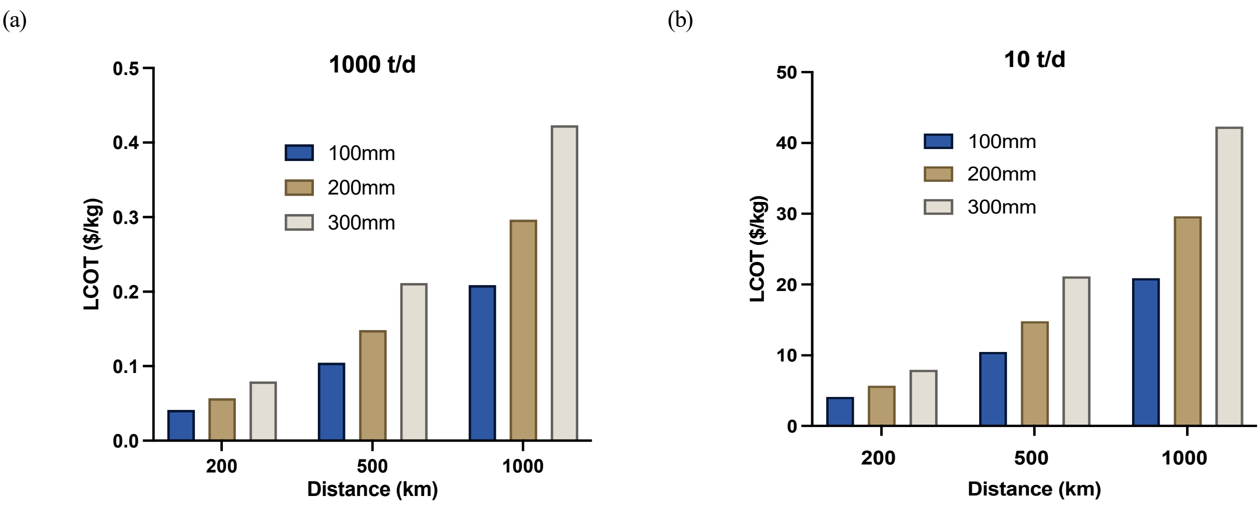

Fig. 2 Levelized cost of transportation (LCoT) for pipe distribution using three pipe diameters: (a) transporting 10 t/d and (b) transporting 1,000 t/d

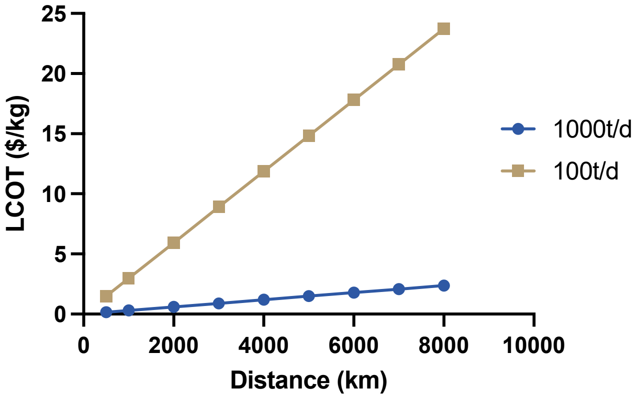

Fig. 3 LCoT for a pipeline transporting 1,000 t/d and 100 t/d across different distances

capacities necessitates larger pipe diameters, which reduce the pressure drop and consequently lower the required recompression power. This leads to significant economies of scale in pipeline transportation. Costs below 1 USD/kgH_2 have also been suggested for large-scale, long-distance hydrogen pipelines (IRENA, 2022). This is consistent with Fig. 3, where this value increases for distances longer than 4,000 km.

3.2.2 Liquid hydrogen shipping

The case of transporting liquefied hydrogen to Nuuk via shipping estimated a cost of 0.12 USD/kg using a tanker capacity of 160,000 m³. The time required for a round trip from the loading terminal in Paamuit to the receiving terminal in Nuuk, including loading and unloading, was calculated as 3.6 d. Assuming 350 operational days annually, the ship can make approximately 96.5 trips per year. The calculated quantity of hydrogen delivered was 3,000 t/d, equivalent to 1,098,372,413 kg/y. This value represents the storage and shipping costs, but excludes the cost of liquefaction. The amount of hydrogen delivered is influenced by the shipping distance owing to the BOG consumed for propulsion, which is factored into the cost model used.

The cost of LH2 shipping is significantly affected by high storage costs, low capacity, and a high BOG rate. This results in a reduced quantity delivered upon arrival at the destination, consequently increasing the LCoT. Furthermore, high ship and storage capital costs are due to the thermophysical properties of hydrogen, which require extremely low storage temperatures and substantial insulation.

The capital cost for a 160,000 m³ capacity ship is calculated as $216,784,000. A 10% increase in this capital cost was applied to account for the uncertainty associated with using the BOG for propulsion. Compared to LNG and methanol tankers, this cost is 10% and 44% lower, respectively. This was obtained from a study by Al-Breiki and Bicer (2020) who analyzed the cost of transporting LH2, ammonia, LNG, methanol, and LOHC (with dimethyl ether (DME) as the LOHC) between Qatar and Japan.

A comparison of our results with the data from Johnston et al. (2022 revealed a discrepancy of 0.03 USD/kg in the shipping transport cost of LH2, with our results being 2.16 USD/kg lower. This variation is attributed to differing operational costs given the scarcity of data on Arctic port infrastructure and operations.

Our model yielded a transportation cost of 1.3 USD/kg as shown in Fig. 4, more than double their reported cost of 0.45 USD/kg (Al-Breiki and Bicer, 2020). This significant discrepancy is likely due to overlooking the ship's return journey and the use of BOG for propulsion. Additionally, methodologies for determining maritime routes and sailing times, which were not considered here, should be a focus area in the future.

Fig. 5 illustrates the impact of varying ship capacity on hydrogen transportation costs. The results indicate an inverse relationship between ship capacity and transportation costs, as ship capacity decreases and transportation costs increase. A 10% reduction in transportation cost was observed when ship capacity rose from 100,000 to 250,000 m³. Although larger ship volumes lead to an increased surface area and higher BOG rates, the overall effect yields a decrease in the levelized transportation cost. This is due to economies of scale; as the nominal storage capacity (double the ship capacity) increases, and annual BOG and associated costs also increase, the overall cost of hydrogen transport diminishes.

3.3 Comparison of Pipeline and Shipping

Fig. 6 compares the transportation costs of LH2 via shipping and compressed hydrogen gas via pipelines. For green hydrogen transported between 200 and 10,000 km, the LCoT for pipelines rises from 0.15 to 2.97 USD/kg. Assuming a constant annual hydrogen delivery of 1000 t/d, pipeline transportation is more cost-effective for distances less than 1500 km, whereas shipping costs remain relatively stable across distances, as shown in Fig. 7. These findings were less optimistic than those of Niermann et al., who indicated that pipelines are generally advantageous for distances of less than 3,000 km.

A comparison of the results of this study with the values in the IEA report revealed a 1.03 USD discrepancy in the conversion and transportation costs for liquefied hydrogen over 1,500 km, with higher values reported in this study. The IEA indicates pipeline transportation and storage costs ranging from 0.2 to 2 USD/kg for distances of up to

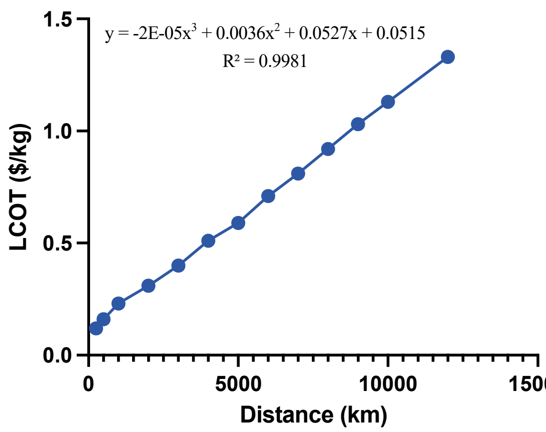

Fig. 4 Cost of transport via shipping across different distances using liquid hydrogen

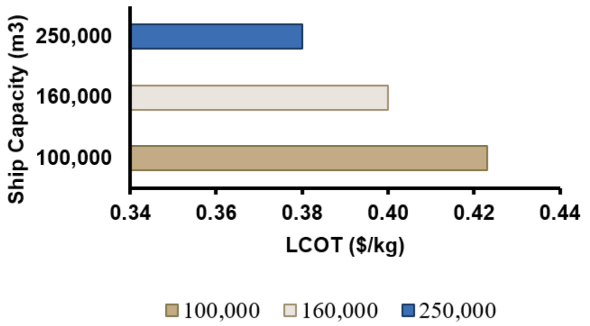

Fig. 5 Sensitivity analysis for shipping hydrogen using different capacities

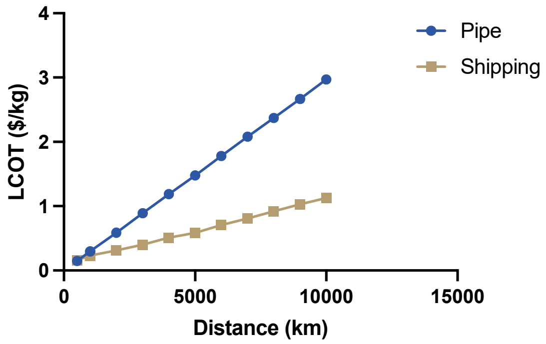

Fig. 6 Transmission distance as a function of LCoT for pipeline and shipping

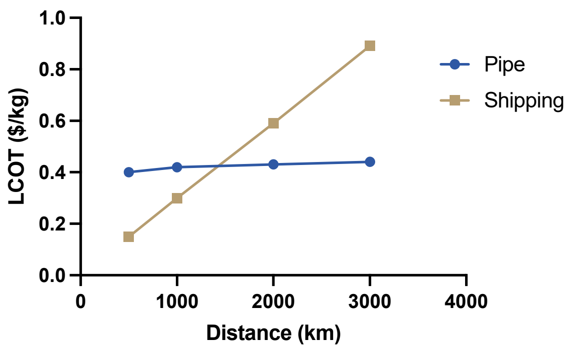

Fig. 7 Transmission distance as a function of LCoT for pipeline and shipping for a fixed capacity of 1,000 t/d.

300 km. A direct comparison is difficult owing to the limited data transparency in the IEA report, particularly regarding pipeline capacity, terminal operations, and storage capacities, which significantly influence costs. Although detailed assumptions and results are essential for a comprehensive comparison, the available data suggest a general alignment of the cost ranges between the two studies.

Fig. 8 presents a comparative economic evaluation of hydrogen production, liquefaction, and transportation costs via shipping and pipeline. Although the pipeline transportation costs exhibit a stronger correlation with distance, the cost of LH2 shipping is less sensitive to distance variations. Liquefaction accounted for 34% of the total cost. The high cost of liquefaction is attributed to the expensive equipment

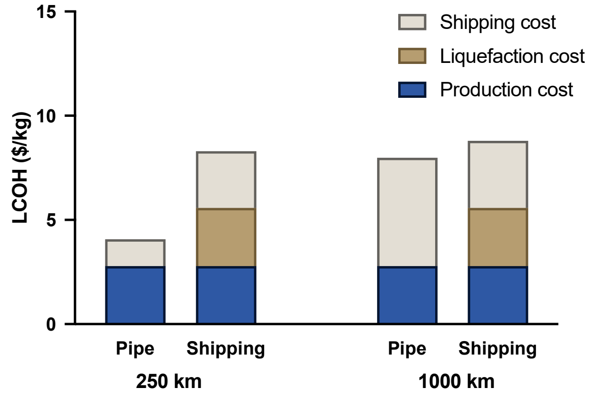

Fig. 8 LCoH for pipe and shipping for a 40 t/d capacity.

and infrastructure required, including the compressors, heat exchangers, and cryogenic materials. The HDSAM model only accounts for the capital cost of the liquefaction plant.

The cold climate in Greenland offers the potential advantage of reduced energy consumption compared to warmer regions. This could significantly decrease the cost of liquefaction. However, further research is required to fully assess this issue. The LCoH with pipeline transportation ranges from 4 to 7 USD for the estimated flow rate, whereas LH2 stands at $8/kg. This value is similar to that in Ishimoto et al. (2020); according to that study, the cost of hydrogen delivered to Rotterdam was lower for LH2 at 5.0 EUR/kg-H2, whereas its transport to Japan was higher at 7 EUR/kg-H2. As mentioned previously, this study only considered electrolysis, which may be a source of disparity compared with other studies.

4. Conclusions

This study examined the cost of transporting hydrogen under Greenland's geographic and environmental conditions via compressed gas pipelines and LH2 tankers. To analyze the complete hydrogen supply chain, the cost of green hydrogen produced from offshore wind was investigated. The methodology used in this study is the first to analyze the entire supply chain cost of hydrogen via pipeline and shipping under Arctic conditions. The results obtained from applying the methodology to hydrogen distribution between Paamuit and Nuuk suggest that pipelines are more economically feasible than LH2 tankers. This assessment was based on the finding that pipelines are optimal for distances of less than 1,500 km, whereas shipping becomes more viable for longer distances and larger hydrogen quantities. The study also revealed that higher hydrogen delivery capacities led to a lower LCoT. Economies of scale were evident, as the LCoT for both pipelines and shipping decreased by approximately 90% when hydrogen production increased from 100 to 1,000 t/d. This model was validated based on values obtained from the literature, and the obtained results demonstrated the economic feasibility of producing and transporting hydrogen from Greenland. Although technological and infrastructural development in the Arctic remains in its early stages, this study highlights the potential of these regions as significant contributors to the global hydrogen economy.

Conflict of Interest

No potential conflict of interest relevant to this article was reported.

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