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Techno-Economic Assessment of Transition Pathways for Hard-to-Abate Sectors

Alternative Propulsion Technologies for Maritime and Off-Road Machinery Industries

Åbo Akademi University



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University / Institution	Qualification / Academic Achievement
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Academic interests include energy systems, industrial management, life-cycle assessment, techno-economic analysis, and energy transition economics.



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Industrial Management
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Åbo, Finland, November 2026

Anthony Katumwesigye

Abstract

This article-based doctoral dissertation examines how decarbonisation pathways in selected hard-to-abate sectors should be assessed when lifecycle boundaries, upstream energy conditions, infrastructure constraints, utilisation patterns, and policy frameworks are made explicit. The study integrates four appended papers within a synthesising kappa and is empirically grounded in short-sea shipping, off-road mobile machinery, and decentralised fuel systems in agriculture. Positioned at the intersection of life-cycle assessment (LCA), techno-economic assessment (TEA), and transition-oriented research, the dissertation addresses a key gap in the literature: while prior studies show that pathway performance depends on boundary assumptions and upstream conditions, they often treat infrastructure utilisation, operational constraints, and policy frameworks as external parameters rather than integral components of feasibility, resulting in a disconnect between analytical comparisons and real-world deployment.

Methodologically, the dissertation applies LCA and TEA in a boundary-explicit and sector-consistent manner, preserving functional-unit integrity across heterogeneous settings. The results show that pathway rankings are highly sensitive to assessment conditions: in short-sea shipping, lifecycle boundaries, methane slip, electricity sourcing, and policy rules materially affect relative performance; in off-road machinery, service-based comparison and infrastructure utilisation shape both environmental and economic outcomes, favouring electrification in high-utilisation contexts; and in decentralised hydrogen systems, electricity price and capacity factor dominate cost and feasibility, constraining viability under low-utilisation conditions.

The central contribution is the development and application of an *adoption-gates framework*, which conceptualises pathway feasibility as conditional on the alignment of upstream energy integrity, infrastructure availability and utilisation, policy and accounting boundaries, and operational compatibility. By linking lifecycle and techno-economic modelling assumptions to real-world deployment conditions, the framework explains why pathways that appear favourable within narrow analytical boundaries may not translate into implementable solutions, thereby advancing pathway evaluation from identifying optimal technologies to analysing conditional feasibility domains in hard-to-abate sectors.

Abstrakt / Sammanfattning

Denna artikelsammanläggningsavhandling undersöker hur omställningsvägar för avkarbonisering i utvalda svårreducerade sektorer bör bedömas när livscykelgränser, uppströms energiförhållanden, infrastrukturella begränsningar, utnyttjandegrad samt policy- och regelverk görs explicita. Studien integrerar fyra bifogade artiklar inom en sammanhållande kappa och är empiriskt förankrad i närsjöfart, mobila arbetsmaskiner utanför vägtrafik samt decentraliserade bränslesystem inom jordbruket.

Avhandlingen är positionerad i skärningspunkten mellan livscykelanalys (LCA), teknisk-ekonomisk analys (TEA) och transitionsforskning och adresserar en central kunskapslucka i litteraturen: även om tidigare studier visar att olika omställningsvägars prestanda är beroende av systemgränser och uppströms förutsättningar, behandlas ofta infrastrukturutnyttjande, operativa begränsningar och policyramverk som externa parametrar snarare än integrerade delar av genomförbarheten, vilket skapar en diskrepans mellan analytiska jämförelser och faktisk implementering.

Metodologiskt tillämpar avhandlingen LCA och TEA på ett gränsmedvetet och sektorkonsistent sätt där funktionella enheter bevaras över olika beslutskontexter. Resultaten visar att rangordningen av olika omställningsvägar är starkt beroende av bedömningsförutsättningar: inom närsjöfarten påverkar livscykelgränser, metanslip, elens ursprung och policybaserade redovisningsregler den relativa prestandan; inom mobila arbetsmaskiner är tjänstebaserad jämförelse och infrastrukturens utnyttjande avgörande för både miljömässiga och ekonomiska utfall, vilket gynnar elektrifiering i högutnyttjade kontexter; och inom decentraliserade vätgassystem är elpris och kapacitetsfaktor avgörande för kostnad och genomförbarhet, vilket begränsar lönsamheten vid låg utnyttjandegrad.

Avhandlingens huvudsakliga bidrag är utvecklingen och tillämpningen av ett *adoptions-grindsramverk*, som konceptualiserar genomförbarheten hos omställningsvägar som beroende av att centrala systemvillkor uppfylls, inklusive uppströms energiintegritet, tillgång till och utnyttjande av infrastruktur, policy- och redovisningsgränser samt operativ kompatibilitet. Genom att koppla livscykel- och teknisk-ekonomiska analysantaganden till faktiska implementeringsvillkor förklarar ramverket varför vissa alternativ framstår som attraktiva under snäva analytiska gränser men inte realiseras i praktiken, och bidrar därmed till att flytta fokus från att identifiera universellt optimala teknologier till att analysera villkorade genomförbarhetsdomäner i svårreducerade sektorer.

List of Publications and Contributions by the Author

This article-based dissertation is based on the following four peer-reviewed publications. The author contributions are stated to clarify the doctoral candidate's role in the conception, analysis, writing, and synthesis of the appended studies.

Paper I

Mayanti, B., Hellström, M., and Katumwesigye, A. (2025). *Assessing the decarbonization roadmap of a RoPax ferry*. Maritime Economics & Logistics, 27, 123–146.

Contribution of the author: The author contributed to the life-cycle and techno-economic interpretation of the fuel-roadmap results, supported the development of the decarbonisation pathway framing, contributed to manuscript development and revision, and integrated the paper into the dissertation synthesis with emphasis on fuel-cycle boundaries, methane-slip sensitivity, and policy exposure.

Paper II

Katumwesigye, A., Hellström, M., and Spohr, J. (2025). *Techno-economic assessment of hydrogen application in cereal crop farming*. Frontiers in Energy Research, 13, 1479212.

Contribution of the author: The author was the lead author and was responsible for the research design, data collection, techno-economic modelling, scenario analysis, interpretation of results, manuscript drafting, and revision. The paper provides the dissertation evidence on utilisation-sensitive hydrogen economics and decentralised fuel-supply feasibility.

Paper III

Katumwesigye, A., Schwartz, H., Gustafsson, M., and Hellström, M. (2025). *A comparative technoeconomic and life cycle assessment of a fully battery-electric RoPax ferry*. Journal of Cleaner Production, 534, 146935.

Contribution of the author: The author was the lead author and was responsible for the case-study design, LCA and TEA model development, data integration, scenario analysis, result interpretation, manuscript drafting, and revision. The paper provides the dissertation evidence on route-level electrification, battery replacement, electricity sourcing, port-energy infrastructure, and policy-internalised cost comparison.

Paper IV

Katumwesigye, A., Spohr, J., Hellström, M., and O'Born, R. (2026). *An integrated life-cycle assessment of three different propulsion pathways for medium-sized wheel loaders under Nordic quarry conditions: A case study*. Journal of Cleaner Production, 574, 149020.

Contribution of the author: The author was the lead author and was responsible for the research design, work-based functional-unit framing, LCA and techno-economic model development, data collection, scenario construction, result interpretation, manuscript drafting, and revision. The paper provides the dissertation evidence on service-based comparison, site infrastructure, utilisation, and adoption conditions for off-road machinery.

Open Access and Re-use Rights

This dissertation is an article-based doctoral dissertation. The appended papers are included in accordance with their respective publication and re-use rights.

Paper I. *Assessing the decarbonization roadmap of a RoPax ferry*. Published Open Access under the licence stated by the publisher.

Paper II. *Techno-economic assessment of hydrogen application in cereal crop farming*. Published Open Access under the licence stated by the publisher.

Paper III. *A comparative technoeconomic and life cycle assessment of a fully battery-electric ROPAX ferry*. Published Open Access under the licence stated by the publisher.

Paper IV. *An integrated life-cycle assessment of three different propulsion pathways for medium-sized wheel loaders under Nordic quarry conditions: A case study*. Published Open Access under the licence stated by the publisher.

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List of Abbreviations

Abbreviation	Definition
BEV	Battery-electric vehicle
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CH_4	Methane
CO_2	Carbon dioxide
CO_2-eq	Carbon dioxide equivalent
EU	European Union
EU ETS	European Union Emissions Trading System
FCEV	Fuel-cell electric vehicle
GHG	Greenhouse gas
GWP	Global warming potential
GWP_{100}	Global warming potential over a 100-year time horizon
H_2	Hydrogen
HDP	Hydrogen demand for machinery operations (Publication II notation)
ICE	Internal combustion engine
IEA	International Energy Agency
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
LBG	Liquefied biogas
LCA	Life-cycle assessment
LCIA	Life-cycle impact assessment
LCOH	Levelised cost of hydrogen
LNG	Liquefied natural gas
MDO	Marine diesel oil
MGO	Marine gas oil
MRV	Monitoring, reporting and verification
N_2O	Nitrous oxide
NPV	Net present value
NRMM	Non-road mobile machinery

Abbreviation	Definition
NZE	Net Zero Emissions scenario
OEM	Original equipment manufacturer
OPEX	Operating expenditure
PEM	Proton-exchange membrane
PtL	Power-to-liquid
PtX	Power-to-X
RA–TCO	Relative-adjusted total cost of ownership
RE	Renewable electrolysis
RFNBO	Renewable fuel of non-biological origin
RoPax	Roll-on/roll-off passenger vessel
Ro-Ro	Roll-on/roll-off
SAF	Sustainable aviation fuel
SDS	Sustainable Development Scenario
SMR	Steam methane reforming
SMR+CCS	Steam methane reforming with carbon capture and storage
STEPS	Stated Policies Scenario
TCO	Total cost of ownership
TEA	Techno-economic assessment
TTW	Tank-to-wake
TtP	Tank-to-propeller
WTT / WtT	Well-to-tank
WTW	Well-to-wake
WtP	Well-to-propeller

Chapter 1

Introduction

1.1 Background: energy use in hard-to-abate segments

The urgency of reducing greenhouse gas emissions has intensified as the impacts of climate change become increasingly evident across environmental, economic, and societal systems. Achieving internationally agreed climate targets, most notably those articulated in the Paris Agreement, requires deep structural transformations in how energy is produced, distributed, and consumed. A subset of sectors continues to account for a disproportionate share of global emissions despite the availability of technological alternatives and increasing policy pressure.

These sectors are commonly referred to as ”hard-to-abate”, signifying industries in which emissions reductions are difficult to achieve despite the availability of technological solutions. The persistence of emissions in these contexts is not merely a function of emissions intensity, but is fundamentally linked to structural and systemic features: elevated intrinsic energy requirements, the need for uninterrupted operation, the predominance of capital assets with extended operational lifespans that inhibit rapid technological turnover, and a reliance on carbon-based feedstocks that are chemically integral to embedded core production processes. As highlighted in major synthesis reports by the Intergovernmental Panel on Climate Change (IPCC), the International Energy Agency (IEA) and the wider transition literature, these characteristics create systemic barriers to rapid decarbonization even where technological alternatives exist (IPCC, 2022a; IPCC, 2022b; Energy Transitions Commission, 2018; Bataille et al., 2018).

In these settings, the prospects for decarbonisation are governed by a complex interplay of factors: not only the adoption of end-use technologies, but also the integrity of upstream energy supply, the presence and utilisation of supporting infrastructure, operational limitations, and the influence of regulatory frameworks (Aminaho et al., 2025; Brynolf et al., 2018; König et al., 2015; Seymour et al., 2024).

To address this system-level complexity, the dissertation employs a conceptual framework defined by four interrelated determinants of pathway feasibility: system-boundary definition, upstream energy integrity, infrastructure availability and utilization, and policy and accounting

rules. This approach is consistent with established methodologies in life-cycle assessment (LCA) and techno-economic assessment (TEA), but extends them by explicitly connecting methodological decisions to the practical realities faced by decision-makers. Rather than treating these factors as mere background context, the dissertation positions them as core components of pathway evaluation, which fundamentally influence both environmental outcomes and economic viability.

1.2 Hard-to-abate transitions

Once hard-to-abate sectors are viewed through this framework, the transition problem becomes more specific. The central issue is not simply whether low-carbon technologies exist, but whether entire pathway configurations can function credibly under real operating conditions. In this dissertation, a **transition pathway** *is understood as a combination of energy carrier, conversion technology, enabling infrastructure, and governing rules that together determine how an activity is performed and how its environmental and economic performance is assessed*. This shifts attention away from single-device substitution and toward the conditions under which competing pathways become feasible, constrained, or systematically mis-evaluated.

The barriers to decarbonising these sectors can be categorised as physical, techno-economic, and systemic—each intersecting in ways that complicate transition trajectories and targets. Physical constraints arise from operational demands such as high energy density, continuous power requirements, long operating durations, and high-temperature processes, all of which limit the applicability of direct electrification or low-density energy carriers in many industrial and transport contexts (IPCC, 2022b; International Energy Agency, 2024; Energy Transitions Commission, 2018). Techno-economic constraints arise from capital-intensive, long-lived assets and supporting infrastructure, which lead to significant path dependencies, slow asset turnover, and elevated transition costs (International Energy Agency, 2025; Bataille et al., 2018). Systemic constraints encompass the wider operational, regulatory, and institutional landscape, including the carbon intensity of upstream electricity, absence or underutilisation of enabling infrastructure, and misalignment between policy or accounting boundaries and engineering realities (IPCC, 2022b; Seemungal et al., 2021). These layered constraints collectively reinforce the understanding that decarbonisation in hard-to-abate sectors is not simply a matter of adopting new technologies, but rather requires coordinated transformation across pathways, infrastructure, and governance systems (Bataille et al., 2018; Korberg et al., 2021; Energy Transitions Commission, 2018).

The urgent need for a systems-oriented approach to decarbonization is stressed by recent emissions data from the energy sector. Despite the accelerated deployment of clean energy technologies, global emissions have not decreased in proportion, highlighting uneven progress in decarbonization across sectors and infrastructure. The IEA reports that energy-related CO_2 emissions reached 37.8 billion tons in 2024 (International Energy Agency, 2025). This figure indicates that, although there have been improvements in electricity generation and some

end-use applications, significant emissions persist in sectors where changes to equipment, fuels, and infrastructure occur gradually. The challenge of transitioning from high-emission sectors therefore does not primarily stem from the absence of alternative technologies; rather, it lies in the specific conditions required to implement these alternatives effectively at scale.

The maritime sector provides a salient example of these dynamics. According to the Fourth International Maritime Organization (IMO) Greenhouse Gas Study, shipping emissions rose from 977 Mt in 2012 to 1,076 Mt in 2018, with shipping's share of global anthropogenic emissions also increasing over this period (Faber et al., 2020). These outcomes further highlight that engine and propulsion efficiency measures are insufficient to counteract emissions growth when global trade and transport demand continue to expand. Furthermore, they reveal that comprehensive pathway evaluation in shipping must extend beyond tank-to-wake carbon accounting to encompass upstream fuel production, methane slip, onboard operational efficiency, route characteristics, structure, and access to shore power. Thus, the need for a holistic approach is not just analytical but also regulatory. This is evident in the IMO's 2023 GHG Strategy and the implementation of FuelEU Maritime. Together, these initiatives highlight the importance of assessing pathways that extend beyond mere incremental efficiency improvements (International Maritime Organization, 2023; European Union, 2023; European Commission, 2025; DNV, 2025a).

Parallel challenges are apparent in the aviation sector, where the issue of energy density is even more pronounced. The continued reliance of commercial aviation on liquid fuels is dictated by stringent requirements for range, payload, and safety, which collectively constrain the short-term viability of battery substitution. With the post-pandemic resurgence of air traffic, emissions have rebounded, positioning sustainable aviation fuel (SAF) as the primary near-term mitigation strategy. Nonetheless, the European Union Aviation Safety Agency (EASA) reports that SAF accounted for only 0.53% of global jet fuel consumption in 2023, highlighting the considerable gap between technical feasibility and meaningful deployment in the system (European Union Aviation Safety Agency, 2025; European Union Aviation Safety Agency, 2024). The implication is that the aviation transition depends not only on identifying alternative fuels but also on feedstock availability, production capacity, certification, cost, and policy support. This is also why hydrogen is analytically relevant beyond its direct use: many future aviation and maritime fuel options depend on hydrogen-derived synthesis routes and therefore inherit the same upstream electricity and utilisation conditions.

Heavy industry exhibits comparable patterns, with persistent emissions rising from entrenched production processes and infrastructural inertia. In steel manufacturing, emissions remain high due to the continued predominance of coal-based reduction methods and the prevalence of large, capital-intensive facilities with extended operational lifespans. Cement production, for its part, is characterised by both fuel- and process-related emissions, the latter of which are not amenable to mitigation through fuel switching alone (International Energy Agency, 2023b; International Energy Agency, 2023a). The Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report highlights that achieving deep decarbonisation in these sectors necessitates

an integrated portfolio of interventions—including efficiency enhancements, electrification, adoption of alternative feedstocks, hydrogen utilisation, carbon capture, and broader system integration—rather than reliance on single technological substitutions (IPCC, 2022a). This perspective reinforces the dissertation's argument that a successful transition is predicated on the coordinated alignment of technologies, infrastructure, upstream supply chains, and institutional frameworks, each unique to its sector.

The increasing prominence of policy developments further amplifies the significance of a systems-based approach. Lifecycle accounting has transitioned from a methodological choice to a fundamental determinant of regulatory compliance and market competitiveness. For example, the FuelEU Maritime regulation mandates well-to-wake accounting practices, thereby rendering upstream emissions, methane slip, and the provenance of electricity essential considerations for commercial operations in maritime transport (European Union, 2023; European Commission, 2025; DNV, 2025a). In this policy environment, parameters that were previously regarded as modelling sensitivities have emerged as critical determinants of pathway credibility and financial exposure (MAN Energy Solutions, 2022). Therefore, assessments of pathways must be explicitly conditional, as a pathway that may seem advantageous within limited operational parameters can lose its credibility when considering upstream emissions, infrastructure constraints, utilisation limits, or relevant policy regulations.

1.3 Scope and rationale

This dissertation does not attempt to cover all hard-to-abate sectors empirically. Instead, it focuses on three decision environments that illuminate different parts of the transition problem while remaining comparable through the framework lens defined above. These settings differ in energy-carrier requirements, infrastructure dependence, and utilisation patterns, but they are all shaped by the same recurring questions: how pathway performance changes with boundary choice, how upstream energy conditions influence lifecycle credibility, how infrastructure constraints affect feasibility, and how policy rules reshape competitiveness.

At a general level, the feasibility space can be interpreted through the interaction between distance from fuelling or charging opportunities and the power or energy demand required to deliver the service. Applications with short, predictable routes and repeated charging opportunities may become suitable for electrification relatively early, provided that grid and charging infrastructure are available. Applications that require higher energy density, longer range, or less predictable operating patterns are more likely to rely on hybrid configurations, renewable liquid fuels, gaseous fuels, or hydrogen-based pathways for longer periods. Figure 1.1 presents an indicative representation of this logic and provides the conceptual backdrop for the case selection used in the dissertation.

Within this broader landscape, *short-sea shipping* is selected because it occupies a particularly informative transitional niche. Some routes are sufficiently short and regular that direct

electrification becomes technically plausible, while others continue to favour liquid or gaseous fuel pathways due to charging constraints, route flexibility, or vessel energy demand. This makes short-sea shipping a useful setting for comparing electrification and fuel-roadmap pathways under explicit lifecycle and policy boundaries. It is particularly relevant under FuelEU Maritime, where well-to-wake accounting makes upstream emissions and methane management directly material to compliance and cost (European Union, 2023; European Commission, 2025; DNV, 2025a). Evidence that methane slip varies across engine type and operating conditions further strengthens the relevance of this case, especially for short-sea profiles characterised by variable loading and frequent manoeuvring (Pavlenko et al., 2020; Kuittinen et al., 2024).

Off-road vehicles (NRMM) are selected because they reveal how strongly transition feasibility depends on duty cycle, site context, and service-based comparison. This category covers a wide range of operating environments, including temporary construction sites, high-utilisation quarries and mines, seasonal farming, remote forestry, and fixed logistics or port applications (Vavra, 2025; Transport and Environment, 2024). The review literature consistently shows that no single pathway can be generalised across these uses. Electrification and hydrogen feasibility are instead shaped by utilisation patterns, charging or refuelling logistics, machine size, daily power demand, and the presence of enabling infrastructure (Antila et al., 2025; Un-Noor et al., 2022; Pesonen et al., 2025). NRMM therefore complements shipping well: both are infrastructure-dependent, but the relevant constraints are distributed differently, with shipping tied primarily to ports and NRMM tied to site-level energy systems.

Decentralised farm hydrogen is included not because hydrogen is assumed to be the universal solution for agriculture, but because it serves as a representative analytical case within a wider family of alternative fuel pathways that become relevant where electrification is constrained. In farming and similar distributed applications, the underlying question is not only whether hydrogen itself can be produced and used economically, but under what utilisation and electricity-cost conditions electricity-derived fuels more broadly become plausible. Hydrogen is especially useful in this regard because it makes the upstream dependence of these pathways highly visible: electricity price, capacity factor, and infrastructure utilisation strongly determine both cost and lifecycle performance (Aminaho et al., 2025). Agriculture provides a particularly useful test case because energy demand is often strongly seasonal and utilisation is therefore structurally constrained. This makes it possible to examine whether decentralised hydrogen can become economically credible under aggregation, shared-use, or improved utilisation scenarios, while also generating insights relevant to other distributed fuel pathways, including hydrogen-derived e-fuels, biomethane integration, and parts of maritime fuel supply (Janke et al., 2020; Yilmaz, 2024; Brynolf et al., 2018; König et al., 2015).

The selected empirical domains are therefore not treated as isolated case studies, but as complementary lenses on a common transition problem. Short-sea shipping foregrounds lifecycle fuel boundaries, methane effects, and policy-linked compliance. NRMM foregrounds work-based functional units, duty-cycle realism, and site infrastructure context. Decentralised farm hydrogen

foregrounds utilisation-sensitive fuel economics and the conditions under which electricity-derived and alternative low-carbon fuels may become plausible outside highly centralised industrial demand. Together, they allow the dissertation to examine how pathway assessment, pathway viability, and pathway enablement intersect across hard-to-abate systems.

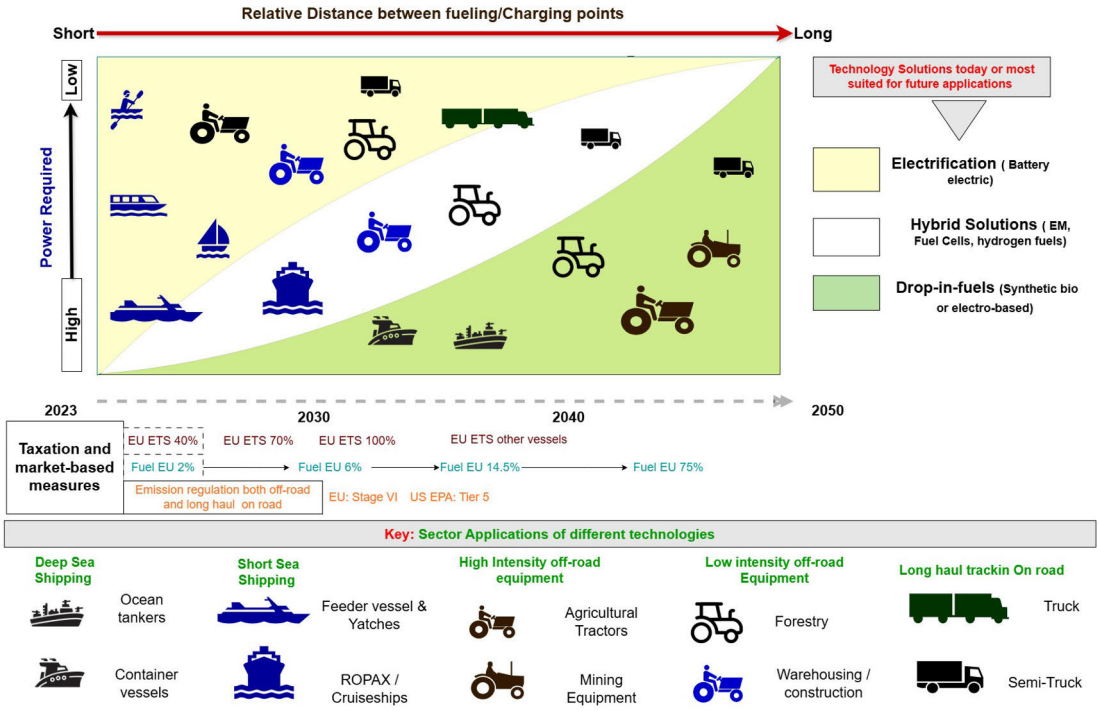


Figure 1.1: Indicative feasibility space for propulsion and fuel pathways across transport and machinery segments.

1.4 Research questions and structure

The aim of this dissertation is to generate decision-relevant evidence on the feasibility of decarbonisation pathways in hard-to-abate sectors under differing lifecycle boundaries, operational conditions, infrastructure constraints, and policy settings. The central claim is not that one technology or fuel pathway universally outperforms all others, but that pathway performance and competitiveness are conditional and should be evaluated against clearly stated environmental, economic, infrastructural, and regulatory assumptions. This position is consistent with current policy developments in sectors such as shipping and aviation, where lifecycle accounting and upstream emissions performance increasingly shape both compliance and transition strategy (International Maritime Organization, 2023; European Commission, 2025; Khalifa et al., 2025).

Accordingly, the dissertation is guided by three cross-cutting research questions.

RQ1. How do lifecycle system boundaries, functional assumptions, and assessment choices influence the identification and comparison of decarbonisation pathways in hard-to-abate sectors?

This question addresses the extent to which comparative outcomes depend on methodological framing, including upstream supply-chain treatment, emissions accounting conventions, and the choice of functional unit. It is motivated by evidence showing that methane slip, electricity sourcing, hydrogen-production pathways, and fuel-chain assumptions can substantially alter lifecycle climate performance and the apparent credibility of alternative pathways in transport and machinery systems (Pavlenko et al., 2020; Kuittinen et al., 2024; DNV, 2025a; European Union, 2023; Aminaho et al., 2025).

RQ2. Under what technical, operational, and market conditions do emerging transition pathways become economically viable and environmentally credible alternatives to incumbent fossil-based systems?

This question examines the conditional nature of pathway feasibility. It focuses on how duty cycle, utilisation, energy price, infrastructure use intensity, service-delivery requirements, and upstream supply conditions shape comparative outcomes. Across the sectors examined in this dissertation, technologies are deployed not in abstract average conditions but to provide transport work, mechanical service, or energy carriers under real operating constraints (Antila et al., 2025; Pesonen et al., 2025; Un-Noor et al., 2022; Aminaho et al., 2025; Janke et al., 2020).

RQ3. What infrastructural, supply-chain, and policy conditions are required to enable the deployment and scaling of these transition pathways?

This question moves beyond comparative performance to the implementation of transitions. It addresses the enabling conditions needed for uptake, including port and site infrastructure, electricity access, hydrogen and fuel supply arrangements, upstream feedstock integrity, and policy frameworks that shape investment signals, compliance exposure, and adoption incentives. It is motivated by the observation that even pathways with favourable environmental or economic indicators may remain constrained if the surrounding systems needed for deployment are absent or misaligned.

The dissertation answers these questions through empirical studies in maritime transport, non-road machinery, and decentralised hydrogen applications. Short-sea shipping is used to examine how lifecycle fuel boundaries, methane-slip effects, electricity sourcing, and port infrastructure shape pathway assessment. Off-road machinery provides a basis for analysing how duty cycle, work-based functional units, and site infrastructure affect comparative feasibility when results are expressed per delivered service output. Decentralised hydrogen in farming is used as a representative case to investigate how utilisation patterns and electricity-price conditions influence the broader feasibility of electricity-derived and alternative low-carbon fuel pathways in distributed and seasonally constrained applications.

The dissertation is structured as an integrative synthesis around these research questions and the adoption-gates perspective. Chapter 2 reviews sector evidence and identifies the principal cross-cutting mechanisms that shape pathway performance and transition feasibility in the

selected domains. Chapter 3 presents the methodological framework applied across the appended papers and defines the synthesis rules used to compare results without conflating incompatible units, scopes, or boundary definitions. Chapter 4 reports the results of the appended studies in their native analytical terms and uses them to answer the research questions through conditional synthesis. Chapter 5 develops the adoption-gates framework from the results and discusses how lifecycle boundary fit, upstream energy integrity, infrastructure readiness and utilisation, and policy-accounting alignment shape practical deployment. Chapter 6 presents the conclusions, and Chapter 7 outlines recommendations and future research.

Chapter 2

Sector evidence

This chapter reviews the sector-specific evidence that motivates the comparative assessment undertaken in the dissertation. It examines short-sea shipping, non-road mobile machinery (NRMM), and farm-adjacent decentralised fuel systems, with particular attention to the conditions that influence environmental, economic, and operational feasibility. The purpose is not to rank technologies across sectors, but to identify recurring mechanisms—including upstream energy dependency, infrastructure requirements, utilisation, operational constraints, and policy boundaries—that subsequently inform the methodological choices in Chapter 3 and the cross-sector synthesis developed in Chapter 5.

2.1 Short-sea shipping

Short-sea shipping is a domain where hard-to-abate constraints translate into differentiated feasibility conditions across routes, vessel classes, and port systems. On the operational side, turnaround times, berth availability, vessel duty cycles, and port-grid capacity shape the extent to which direct electrification or hybrid solutions are viable. On the regulatory side, maritime climate policy increasingly prices not only tank-to-wake emissions but also upstream emissions and non-CO_2 effects, making well-to-wake (WTW) performance a dominant decision variable rather than a secondary modelling parameter (European Commission, 2026b; DNV, 2025a). Recent policy developments crystallise this trend: FuelEU Maritime adopts a fleetwide 2020 WTW baseline of 91.16 gCO_2e/MJ and requires a 2% reduction from 2025, tightening progressively toward 80% by 2050 (European Union, 2023; DNV, 2025a). As a result, pathway selection in short-sea shipping is increasingly tied to the credibility of upstream supply chains and ship–port energy interfaces.

The empirical relevance of this segment is visible in EU monitoring, reporting and verification (MRV) data. In the 2024 reporting year, the MRV-covered fleet comprised approximately 12,700 ships and emitted 144.9 Mt CO_2. When methane and nitrous oxide are included, total reported greenhouse gas emissions reached 148.6 Mt CO_2e. Fuel demand also remained substantial:

ships within the MRV scope consumed 46.8 Mt of fuel in 2024, of which 91.4% consisted of conventional marine fuels, while LNG accounted for 7.5% and other fuels only 1.1% (European Commission, 2026a). These figures show that European maritime decarbonisation remains fundamentally a fuel-substitution and energy-infrastructure challenge, rather than only an onboard technology challenge.

Within the MRV fleet, RoPax, Ro-Ro, passenger, and container/Ro-Ro cargo vessels are particularly relevant to short-sea decarbonisation because they are closely associated with regional, coastal, and intra-European services. The 2019 MRV dataset shows that RoPax ships emitted 14.82 Mt CO_2 across 389 ships, Ro-Ro ships emitted 6.19 Mt CO_2 across 275 ships, passenger ships emitted 7.00 Mt CO_2 across 179 ships, and container/Ro-Ro cargo ships emitted 1.54 Mt CO_2 across 76 ships (European Commission, 2021). These vessel classes therefore combine operational suitability for route-specific decarbonisation with material emissions relevance. Table 2.1 summarises the 2019 MRV evidence for the short-sea-relevant vessel categories used to motivate the RoPax case-study focus in this thesis.

This port-interface relevance is further supported by Eurostat vessel-arrival statistics. Figure 2.1 shows the distribution of vessels arriving at EU main ports by vessel type in 2024. The figure is based on inward declarations at main ports, defined as ports handling more than one million tonnes of goods or 200,000 passengers annually (Eurostat, 2026). In 2024, approximately 2.2 million vessels entered EU main ports. Cargo, non-specialised vessels, a category that includes Ro-Ro vessels, represented the largest share of port calls, accounting for 69.9% of vessel arrivals and 58.9% of gross tonnage. Passenger vessels, excluding cruise passengers, accounted for 19.6% of vessel arrivals, while liquid bulk and container vessels accounted for 3.8% and 3.1%, respectively (Eurostat, 2026). This confirms that short-sea-relevant vessel types are not only important in emissions accounting, but also central to the everyday utilisation of European port infrastructure. The figure therefore complements the MRV evidence by linking vessel-type emissions to port-call frequency and ship–port energy-system requirements.

Table 2.1: EU MRV evidence for short-sea-relevant vessel categories in 2019.

Ship type	**Number of ships**	**Total CO_2 emissions**	**Average CO_2 per ship**
RoPax ship	389	14.82 Mt CO_2	38,088 t CO_2/ship
Ro-Ro ship	275	6.19 Mt CO_2	22,496 t CO_2/ship
Passenger ship	179	7.00 Mt CO_2	39,102 t CO_2/ship
Container/Ro-Ro cargo ship	76	1.54 Mt CO_2	20,202 t CO_2/ship

Source: European Commission EU MRV Annual Report for 2019 emissions (European Commission, 2021).

More recent MRV evidence confirms that these categories remain material in the European fleet. In 2024, RoPax ships emitted approximately 13.7 Mt CO_2, Ro-Ro ships approximately 5.3 Mt CO_2, passenger ships approximately 7.3 Mt CO_2, and container/Ro-Ro cargo ships approximately 1.2 Mt CO_2 (European Commission, 2026a). Although direct year-to-year

comparison requires caution because of changes in reporting scope and post-Brexit geographical coverage, the updated data confirm that ferry-oriented and wheeled-cargo vessel classes remain important targets for European short-sea shipping decarbonisation.

Three pathway families dominate short-sea decarbonisation: (i) fuel switching using conventional or transitional fuels, including MGO/MDO, LNG, and methanol blends; (ii) direct electrification through battery-electric or plug-in hybrid systems; and (iii) advanced biofuels and synthetic fuels, including e-methanol, e-diesel, and ammonia-based pathways. Fuel switching preserves operational patterns but faces intensifying scrutiny under WTW accounting. Electrification offers near-complete tank-to-wake reductions but depends on port infrastructure, electricity sourcing, charging windows, and route geometry. Synthetic fuels decouple vessels from port-charging constraints but shift feasibility to upstream electricity supply, CO_2 sourcing, fuel certification, and fuel-production cost.

LNG illustrates these dynamics. It is already a visible transitional fuel in the MRV fleet, accounting for approximately 7.5% of reported fuel consumption in 2024 (European Commission, 2026a). While LNG lowers combustion CO_2 relative to conventional oil-based marine fuels, lifecycle evidence shows that benefits can vanish once upstream leakage and methane slip are accounted for. Pavlenko et al. (2020) report that low-pressure dual-fuel four-stroke engines can increase life-cycle GHG emissions by 70–82% over MGO when evaluated with a 20-year global warming potential. Independent summaries report similar conclusions (DieselNet, 2020). Real-world measurements reinforce this concern: Kuittinen et al. (2024) report methane slip of 2.3–3.0 g/kWh at mid loads of 54–80%, rising to 10 g/kWh at 25% load and 21 g/kWh at 12% load. Such load-dependence is especially relevant in short-sea duty cycles, where manoeuvring, port approaches, acceleration, hotel loads, and partial-load engine operation can form a significant share of the operating profile.

FuelEU Maritime embeds these upstream sensitivities into compliance exposure. Its WTW framework covers the greenhouse gas intensity of energy used by ships, including CO_2, methane, and nitrous oxide over the fuel lifecycle (European Union, 2023; European Commission, 2026b). Technical guidance confirms the same baseline and trajectory, including the 91.16 gCO_2e/MJ 2020 reference value and the progressive reduction pathway toward 2050 (DNV, 2025a). For operators, this makes upstream fuel integrity—not only fuel price—a central determinant of compliance risk.

Electrification forms a structurally different pathway and is particularly relevant for RoPax and passenger ferry operations because these vessels often operate on fixed routes with repeated port calls, predictable schedules, and recurring berth windows. Its feasibility hinges on port power, charging strategies, vessel scheduling, and stability of electricity procurement. Life-cycle and cost studies emphasise electricity mix and battery replacement as key determinants of benefits (Perčić et al., 2022). Case studies show that charging windows, route length, and berth time dominate viability (Kanchiralla et al., 2025). Route-level analyses indicate that only a subset of short-sea routes are compatible with full electrification without substantial port

upgrades (Siljama et al., 2023). Port power studies also highlight substantial investment needs in microgrids, shore-power systems, and high-capacity charging infrastructure (Siljama et al., 2023). The ship–port interface is therefore part of the decarbonisation boundary rather than an external condition. This is also supported by MRV evidence showing that emissions at berth form a material component of maritime emissions, especially for passenger and ferry-type vessels with significant hoteling and auxiliary power demand (European Commission, 2021).

Industry behaviour reflects uncertainty. DNV's Alternative Fuels Insights platform shows that 2024 saw 515 alternative-fuel vessel orders, 38% more than in 2023, distributed across LNG, methanol, ammonia, LPG, and hydrogen rather than converging on one fuel (DNV, 2025b). Methanol orders reached 166 vessels, LNG 264, and ammonia 27, including the first non-gas-carrier ammonia-fuelled vessel designs (DNV, 2025b). This multi-fuel portfolio indicates hedging behaviour under tightening policy, uncertain fuel availability, and uneven infrastructure maturity.

Overall, short-sea shipping is a multi-pathway domain where WTW performance, upstream integrity, port infrastructure, and regulatory coupling jointly determine feasibility. Electrification is robust where infrastructure aligns with operational needs. Transitional fuels face tightening methane and WTW scrutiny. Synthetic fuels depend heavily on upstream electricity cost, carbon sourcing, and certification. These short-sea mechanisms—strong upstream dependency, route and port power constraints, and WTW compliance exposure—are summarised in Table 2.2 under the short-sea column.

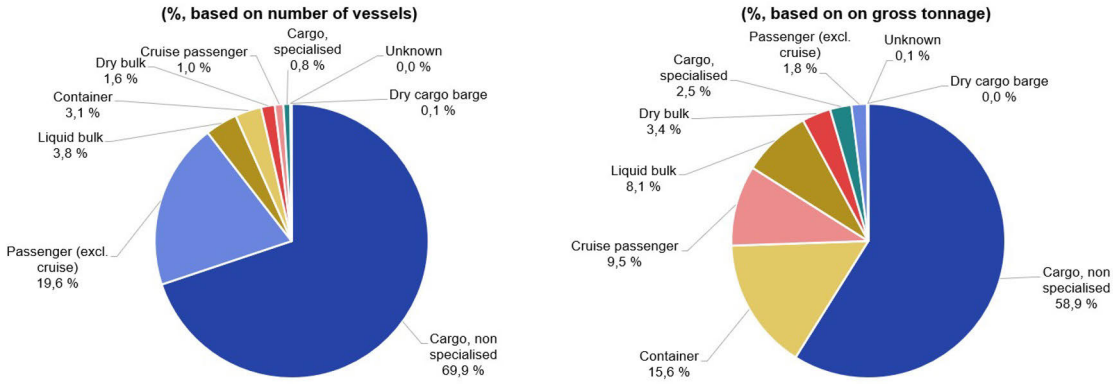


Figure 2.1: Vessel arrivals at EU main ports by vessel type in 2024. Data are based on inward declarations. Source: Eurostat, online data code `mar_mt_am_csvi` (Eurostat, 2026).

2.2 Off-road vehicles

Off-road vehicles (Non-Road Mobile Machinery) encompass construction, quarrying, mining, agriculture, forestry, ports, and logistics— each with distinct duty cycles and utilisation patterns.

Reviews emphasise that electrification potential varies widely across these segments (Antila et al., 2025; Un-Noor et al., 2022; Pesonen et al., 2025). Industry analyses similarly note that decarbonisation requires application-specific and technology-agnostic approaches (Vavra, 2025).

Construction sites exhibit transient high-power loads, variable duty cycles, and temporary or weak grid connections. Electrification depends heavily on access to high-power charging or mobile systems (Vavra, 2025). Comparative cost studies show that although electric equipment reduces noise and emissions, total cost of ownership remains sensitive to charging logistics and equipment costs (Un-Noor et al., 2022; Kafashan et al., 2025). This supports project-level rather than fleet-level planning.

Mining is often more suitable for electrification due to high utilisation and predictable cycles. Energy-delivery rate becomes the binding constraint. A 2025 VTT/Aalto study shows that series-hybrid haul trucks can reduce fuel use by 17%, while trolley-electric systems can reduce fuel consumption by up to 91% and increase productivity (Baranauskas et al., 2025). In some downhill-loaded cases, regeneration may eliminate the need for external charging. These findings validate a site-systems perspective: mine geometry, haul length, and layout determine pathway feasibility.

Agriculture exhibits the strongest utilisation asymmetry. Machinery experiences intense seasonal peaks and long idle periods. Downtime during peak seasons incurs disproportionately high opportunity costs (Janke et al., 2020). Electrification is emerging in controlled environments but heavy field machinery still relies on liquid fuels or hybrid systems requiring rapid refuelling (Renewable Energy Association, 2024).

Forestry and remote operations face grid constraints and long transport distances. Electrifying forest machinery requires coordinated deployment of high-capacity chargers, mobile energy storage, and strategic charging hubs. The TREE project demonstrates this system-level approach (Skogforsk, 2023).

Policies exert indirect but substantial influence. The EU Stage V regulation—currently the strictest NRMM pollutant standard—sets limits on CO, NO_x, HC, PM, and particle number (European Union, 2016). In-service monitoring has revealed significant real-world variability and gaps in regulating low-load operation (Association for Emissions Control by Catalyst, 2024; United Nations Economic Commission for Europe, 2024). Municipal zero-emission site requirements also create localised adoption pressure (Skogforsk, 2023).

In summary, NRMM feasibility depends on the alignment between duty-cycle realism, utilisation, and enabling infrastructure. Electrification excels in predictable, high-utilisation, grid-accessible contexts. Hybrid and fuel-based pathways remain necessary under high-power, long-shift, or weak-grid conditions. NRMM's feasibility levers—utilisation dominance, site-specific constraints, and hybrid enabling assets—align with the NRMM column in Table 2.2.

2.3 Farm energy carriers: hydrogen, biomethane, and farm-adjacent e-fuels

Agriculture is modelled as a distributed, seasonally constrained energy-demand system where low-carbon options include electrification, drop-in renewable liquids, biomethane, and hydrogen. Renewable liquid fuels such as HVO and biodiesel offer near-term mitigation where electrification faces operational limits (International Energy Agency, 2024). Seasonal peaks create utilisation structures that make high-CAPEX energy systems challenging unless costs are shared or loads aggregated. Technical assessments confirm wide variability in utilisation and reliability (Janke et al., 2020). Thus, decarbonisation must be approached as portfolio optimisation.

Hydrogen is analytically important because it isolates utilisation-driven economics. Techno-economic assessments show that electricity price and capacity factor dominate LCOH, with CAPEX and financing secondary (Aminaho et al., 2025). A recent comparison of alkaline and PEM electrolysers provides updated cost structures, performance differences, and decision-making criteria (Shanian et al., 2024). Agriculture's seasonal fuel demand peaks reinforce the need for aggregated offtake and hybrid use-cases (Yilmaz, 2024).

Biomethane and the biogas value chain constitute the second pathway. Anaerobic digestion plants produce biogas, from which CO_2 is separated during upgrading. This high-purity biogenic CO_2 is often vented but offers significant potential for utilisation. Cordova et al. identify multiple downstream applications for this CO_2 stream (Cordova et al., 2023), and analyses emphasise its emerging strategic role in carbon management and synthetic fuel production (European Biogas Association, 2025). Reviews report similar findings, noting the scalability of biogenic CO_2 (Food and Agriculture Organization, 2023).

Farm-adjacent e-fuels further extend this coupling logic. Power-to-liquids systems require renewable electricity, water, and CO_2. Cost studies show that electricity and CO_2 sourcing dominate PtL fuel prices (Seymour et al., 2024). Analyses of PtL-SAF cost trajectories confirm strong sensitivity to electricity availability and CO_2 capture costs (Seymour et al., 2024). Logistics and regional CO_2 supply chains further shape viability, highlighting the need for coordinated regional hubs rather than farm-scale production.

Seasonality plays a decisive role across pathways. Machinery utilisation varies dramatically, with long periods of underuse punctuated by intense operational windows (Janke et al., 2020). This variability affects fuel consumption and the viability of infrastructure-heavy pathways. Work-based functional units better reflect machinery service delivery than per-hour or engine-based metrics (Pesonen et al., 2025).

Taken together, this chapter situates agriculture within a multi-pathway low-carbon landscape. Hydrogen clarifies utilisation-driven economics. Biomethane and biogenic CO_2 streams establish a regional resource foundation. Renewable drop-in fuels support near-term reductions. Farm-associated PtL systems hinge on regional coordination. Farm-adjacent decentralised fuels therefore hinge on electricity availability, unit utilisation, and certification value realisation, as

captured in the farm-adjacent column of Table 2.2.

2.4 Methodological challenges in cross-sector comparison

The sector evidence presented in this chapter highlights several methodological challenges when comparing alternative abatement pathways across different hard-to-abate applications. Although short-sea shipping, non-road mobile machinery (NRMM), and farm-adjacent decentralised fuel systems differ in their technical characteristics and operational settings, the comparison of pathways in each case is affected by similar questions concerning system boundaries, upstream energy conditions, infrastructure utilisation, policy treatment, and the definition of the service being provided.

One challenge is that the pathways do not provide directly comparable services. Short-sea shipping is evaluated in relation to transport work, NRMM in relation to productive work and duty cycles, while decentralised fuel systems are evaluated through energy or fuel production under variable demand. A common functional unit across all three sectors would therefore introduce additional assumptions rather than improve comparability. The comparison must instead preserve the functional basis appropriate to each application.

A second challenge concerns the definition of lifecycle boundaries. Technologies that appear favourable at the point of use may perform differently when upstream electricity generation, fuel production, methane slip, hydrogen production, or CO_2 sourcing are considered. Likewise, the economic performance of infrastructure-intensive pathways depends strongly on the level at which charging, refuelling, production, or storage infrastructure is utilised. These factors make pathway performance dependent not only on the technology itself, but also on the energy and operational system in which it is deployed.

To synthesise the cross-sector patterns observed in this chapter, Table 2.2 illustrates how these methodological challenges appear in the three empirical settings. The table is not intended to establish a common ranking across the sectors, but to show how upstream energy dependency, enabling infrastructure and utilisation, policy boundaries, and operational envelopes can influence the outcome of pathway comparisons.

These observations provide a methodological bridge to Chapter 3. They indicate why pathway comparison requires explicit attention to system boundaries, functional units, upstream energy conditions, infrastructure utilisation, and context-specific assumptions. Chapter 3 therefore explains how the lifecycle and techno-economic methods used in the appended papers were selected and combined while preserving the methodological differences required by each case. Chapter 5 subsequently draws on the resulting cross-paper evidence to develop the adoption-gates synthesis and decision logic.

Table 2.2: Cross-sector comparison of pathway mechanisms and feasibility determinants across short-sea shipping, off-road machinery, and farm-adjacent decentralised fuels.

Mechanism / Condition	Short-sea shipping	Off-road machinery (NRMM)	Farm-adjacent decentralised fuels
Upstream energy dependency	Highly sensitive to electricity carbon intensity, LNG methane slip, and CO_2 sourcing.	Grid carbon intensity and upstream emissions dominate lifecycle outcomes.	Extremely sensitive to electricity price, capacity factor, and biogenic CO_2 purity.
Enabling infrastructure & utilisation	Port power, berth charging/bunkering, and corridor utilisation drive feasibility.	Site power, mobile chargers, and duty-cycle consistency determine cost-effectiveness.	Electrolyser/upgrading utilisation dominates cost; requires aggregated demand.
Policy & certification boundaries	Driven by IMO and FuelEU Maritime WTW rules.	Stage V, local zero-emission site rules, and certification interactions.	Certification, guarantees of origin, biomethane credits, and RFNBO rules influence value.
Operational envelope	Defined by route geometry and energy-density requirements.	Defined by site geometry and heterogeneous duty cycles.	Defined by regional energy systems and production–consumption coupling.
Feasibility mechanism	Upstream dependency + port utilisation + compliance.	Utilisation + site-specific constraints + enabling infrastructure.	Electricity availability + utilisation + certification.

Chapter 2 summary

Key takeaways: Across short-sea shipping, NRMM, and farm-adjacent fuel systems, pathway feasibility is repeatedly shaped by upstream energy conditions, infrastructure availability and utilisation, operational requirements, and policy boundaries. Because the sectors deliver different services, credible comparison also requires sector-appropriate functional units and lifecycle boundaries. These recurring methodological challenges provide the basis for the assessment approach developed in Chapter 3.

Chapter 3

Methodology

This chapter presents the methodological framework used across the dissertation. It outlines the roles of life-cycle assessment (LCA) and techno-economic assessment (TEA), explains how these methods are operationalised in the appended publications, and defines the rules used for cross-paper synthesis. Particular attention is given to system boundaries, functional units, utilisation, infrastructure, and policy conditions that affect the interpretation of pathway performance.

3.1 Methodological stance

The methodological challenges identified in Section 2.4 motivate the combined use of lifecycle and techno-economic assessment in this dissertation. The task of the kappa is not to re-run the calculations reported in the appended publications, but to make their analytical logic explicit and to establish a defensible basis for synthesising findings across different sectors and decision contexts. The central methodological stance is that pathway feasibility is *conditional* on boundary choice, upstream energy integrity, infrastructure utilisation, and policy accounting rules; therefore, the thesis treats these items as part of the decision model rather than as discussion-only context (European Commission, 2025; DNV, 2025a; European Union, 2023).

Accordingly, results must be reported in the *native* functional units and boundaries used by each paper, because converting results post hoc can introduce hidden assumptions or misleading equivalences, for example by mixing transport work with delivered productive output. This is especially important under lifecycle-intensity regulation, where upstream emissions can invert rankings: tank-to-wake (TTW) improvements do not guarantee well-to-wake (WTW) benefits when methane slip or electricity mix is material (Pavlenko et al., 2020; Kuittinen et al., 2024; European Commission, 2025; Seithe et al., 2020). Consequently, the kappa's synthesis is expressed as robust mechanisms (for example, grid dependence, utilisation dependence, and compliance exposure) and as conditional "if–then" conclusions rather than as a single universal ranking.

The chapter is organised as follows. Section 3.2 defines the LCA framework used as a pathway method and clarifies boundary and functional-unit discipline. Section 3.3 defines the TEA framework used as a decision method and explains why utilisation and infrastructure allocation must be represented explicitly. Section 3.4 maps these concepts to the four appended papers and highlights paper-specific operationalisation (MRV transport work in short-sea shipping, route-lifetime WTW in the battery-electric ferry benchmark, NPV/LCOH in farm hydrogen, and work-based TEA–LCA in off-road vehicles). Section 3.5 states the synthesis rules that prevent unit mixing and keep cross-paper inference defensible.

3.2 Life-cycle assessment

LCA is used in this dissertation to quantify how environmental burdens shift across the value chain when energy carriers and conversion technologies change. In hard-to-abate transitions, such burden shifting is not a secondary effect: electrification and hydrogen pathways reduce or eliminate use-phase emissions but increase dependence on upstream electricity carbon intensity, hydrogen production routes, and enabling infrastructure. This is why ISO-standard LCA principles (goal and scope definition, inventory analysis, impact assessment, and interpretation) are essential for credible pathway comparison; without clear scope and boundary specification, differences between pathways can become artefacts of inconsistent accounting rather than real performance differences (International Organization for Standardization, 2006a; International Organization for Standardization, 2006b).

Three boundary families recur across the thesis because they correspond to real compliance and decision questions. First, *well-to-tank* (WTT) captures upstream production and delivery emissions for fuels and electricity. Second, *tank-to-wake/propeller* (TTW/TtP) captures use-phase emissions, including non-CO_2 effects that are operationally linked, such as methane slip in LNG engines. Third, *well-to-wake/propeller* (WTW/WtP) captures full fuel-cycle emissions and is increasingly required in regulatory contexts that use lifecycle-intensity accounting (European Commission, 2025; DNV, 2025a; European Union, 2023). In the appended studies, the WtT–TtP distinction and combined WtP boundary are applied in the short-sea fuel-roadmap assessment (Publication I), while the WTT–TTW and combined WTW boundary are applied in the battery-electric RoPax assessment (Publication III). The wheel-loader study extends the lifecycle boundary further by modelling the machinery from cradle-to-grave and its energy carriers from cradle-to-use (Publication IV). Publication II uses an operational farm-energy system boundary for machinery fuel demand and decentralised hydrogen production rather than a comparative WTW LCA boundary.

In short-sea shipping, this boundary discipline is particularly important because methane slip can materially alter LNG pathway performance, and published evidence shows that slip is load-dependent and therefore sensitive to short-sea operational profiles (Pavlenko et al., 2020; Kuittinen et al., 2024). More broadly, maritime LCA work has shown that vessel type, fuel

supply chain, and operational profile must be assessed together if lifecycle results are to remain representative of real operating conditions (Seithe et al., 2020).

Functional-unit integrity is the second LCA credibility requirement. A functional unit must represent the delivered service rather than merely the energy consumed. This thesis therefore respects paper-specific functional units: MRV-style transport work (pax-nm and ton-nm) with allocation in the short-sea roadmap (Publication I); 30-year route operation for the battery-electric RoPax benchmark (Publication III); and delivered productive output (tonnes moved) for the off-road quarry-duty wheel loader (Publication IV). Publication II does not use a comparative LCA functional unit; instead, machinery fuel demand derived from farm operations provides the demand basis for sizing and techno-economic assessment of the decentralised hydrogen system.

This choice is consistent with sector literature emphasising that off-road machine comparisons must be duty-cycle realistic and service-based, because per-hour or per-energy comparisons can misrepresent both cost and emissions when productivity differs (Antila et al., 2025; Pesonen et al., 2025; Un-Noor et al., 2022). It is also consistent with broader transport assessment work showing that comparisons across powertrain options remain sensitive to mission profile, operational boundary, and the infrastructure assumed to support them (Seemungal et al., 2021).

A third LCA requirement in transition assessment is interpretability under upstream variability. Electricity carbon intensity varies substantially by region and time; therefore, electrification results remain conditional unless electricity procurement is specified. This is why the battery-electric ferry benchmark separates manufacturing, WTT, and TTW phases and explicitly tests electricity sourcing conditions (Publication III), and why the off-road study shows that hydrogen pathways can invert relative to diesel in carbon-intensive electricity contexts (Publication IV). This is not a modelling artefact; it follows from basic lifecycle logic and has been repeatedly highlighted in lifecycle studies of maritime fuels, vessel operations, and fuel supply chains (Seithe et al., 2020; Pavlenko et al., 2020). In parallel, heavy-duty decarbonisation assessments have stressed that future environmental comparison should also include the infrastructure required for alternative powertrain configurations, because infrastructure is part of the real system that enables zero-emission operation (Seemungal et al., 2021).

Finally, because this dissertation is practitioner-facing, LCA results are interpreted through adoption gates: upstream energy integrity, infrastructure availability, and policy boundary. Under FuelEU Maritime, upstream emissions and non-CO_2 gases are compliance-relevant, which means that LCA boundary choices affect economic competitiveness rather than environmental reporting alone (European Commission, 2025; DNV, 2025a). Therefore, LCA is used to test whether a pathway remains low-impact under realistic upstream energy conditions, application-specific duty cycles, and policy conditions.

This emphasis on boundary integrity is also consistent with recent literature on alternative fuel pathways beyond the immediate sectors studied in the appended papers. For example, Khalifa et al. (2025) assess waste-based sustainable aviation fuel blends under a well-to-wake framework and combine life-cycle assessment with Monte Carlo uncertainty analysis to compare

seven conversion pathways. Their study shows that comparative conclusions depend not only on the fuel pathway examined, but also on the environmental indicator and the extent of upstream variability represented in the analysis. This supports the methodological position adopted in the present dissertation: pathway assessment should not rely solely on deterministic point estimates or tailpipe-focused metrics where upstream assumptions materially affect interpretation.

3.3 Techno-economic assessment

TEA is used in this dissertation to evaluate whether pathways that appear environmentally favourable can be financed and operated under realistic cost structures, utilisation patterns, and policy exposure. In capital-intensive transitions, unit economics depend as much on utilisation and infrastructure allocation as on component efficiency. This is especially true for charging systems, electrolysers, hydrogen storage and dispensing, and high-power grid upgrades, whose unit cost is strongly shaped by annual throughput and capacity factor. The TEA evidence base for hydrogen is explicit: a recent Applied Energy review of electrolyser TEA identifies electricity price and capacity factor as dominant determinants of levelised cost of hydrogen (LCOH), with CAPEX, lifetime, and financing also remaining important (Aminaho et al., 2025). Reviews of electrofuels reach a similar conclusion, identifying electricity price, electrolyser investment, operating hours, and stack replacement as dominant cost drivers across hydrogen-derived fuel pathways (Brynolf et al., 2018; König et al., 2015).

This dissertation therefore treats utilisation as a first-order variable rather than as a sensitivity afterthought. In farm hydrogen, the baseline feasibility challenge arises from seasonal demand and low capacity factor; improved utilisation scenarios materially reduce LCOH and shift feasibility conditions. In off-road vehicles, infrastructure utilisation depends on whether charging or refuelling assets are allocated to a single machine or shared across a fleet; this can materially change RA–TCO per tonne moved even when the machine itself remains unchanged. In short-sea shipping, charging infrastructure and port power upgrades similarly depend on utilisation, expressed through vessel frequency and terminal throughput, and therefore infrastructure sharing and standardisation become adoption levers rather than merely engineering design choices. This emphasis is consistent with the broader literature on agricultural electrification, where seasonal loads, renewable integration, storage design, and capital intensity create tightly coupled utilisation constraints (Stakens et al., 2023).

A second TEA requirement is time consistency. Fuel roadmaps and infrastructure investments unfold over decades, and policy cost exposure often intensifies over time. Therefore, TEA must specify time horizon, discounting assumptions, replacement cycles (for example, battery replacement), and residual value treatment. Although the four appended papers use different decision objects (roadmap fuel choice, route-lifetime ferry concept, farm hydrogen project, and quarry-duty machine procurement), they share the same economic logic: compare pathway economics over the relevant time horizon under internally consistent assumptions and report

results in decision-relevant metrics. Comparative maritime TEA studies reinforce this point by showing that total cost of ownership is shaped not only by fuel cost, but also by propulsion-system cost, storage requirements, cargo-space penalties, utilisation rate, and infrastructure assumptions (Korberg et al., 2021).

A third requirement is policy-boundary explicitness. In shipping, EU ETS and FuelEU Maritime mechanisms can alter relative competitiveness. If TEA is performed on fuel cost alone, it can misstate adoption signals under the real compliance environment. Therefore, the battery-electric ferry benchmark explicitly evaluates competitiveness under EU policy mechanisms, and the short-sea roadmap evaluates fuel and carbon costs under multiple carbon-price trajectories. This approach aligns with the broader point that under lifecycle policy, economic feasibility depends on both direct costs and compliance-related costs or revenues (DNV, 2025a; European Commission, 2025; European Union, 2023). It also aligns with business-oriented shipping studies showing that pathway adoption is shaped not only by fuel and technology cost, but by customer willingness to absorb low-carbon transport premiums and by how those costs are distributed across actors in the value chain (Schwartz, Gustafsson, et al., 2020; Schwartz, Solakivi, et al., 2022).

Finally, TEA credibility requires that uncertainty is represented in a form appropriate to the decision. Some uncertainties are scenario-like, such as policy trajectories, electricity sourcing, and fuel availability, while others are parametric, such as CAPEX, utilisation, and energy prices. The dissertation preserves each paper's uncertainty representation and does not collapse it into a single generic uncertainty number, because the relevant decision risk differs by sector: policy and fuel availability dominate some shipping choices, while utilisation dominates decentralised hydrogen feasibility. More generally, comparative decarbonisation assessments in heavy-duty transport have made the same methodological point: technologies should be compared under explicit assumptions regarding technical readiness, infrastructure, LCA/WTW performance, and TEA rather than as isolated engineering options (Seemungal et al., 2021).

3.4 How the methods are operationalised in the appended papers

The appended papers implement LCA and TEA in ways that are tailored to their decision environments, consistent with best practice in sector-specific pathway assessment.

Paper I (short-sea roadmap) evaluates fuel switching (MDO, LNG, LNG&LBG, LBG) under a well-to-propeller boundary, using MRV-style metrics and transport-work intensities (gCO_2/pax-nm; gCO_2/ton-nm) with explicit allocation between passenger and cargo services. This allocation is methodologically necessary because RoPax services deliver two distinct functions and because cost exposure mechanisms differ between passenger tickets and freight pricing. The paper further computes fuel and carbon costs under multiple carbon-tax schemes

and fuel price cases, translating pathway economics into adoption-relevant price exposure. This operationalisation is consistent with maritime lifecycle work showing that vessel function, operational profile, and fuel-chain assumptions must be treated jointly rather than abstracted away (Seithe et al., 2020).

Paper III (battery-electric short-sea benchmark) evaluates a fully battery-electric RoPax concept under WTW boundaries over a 30-year operational lifetime. Methodologically, the paper separates manufacturing, WTT, and TTW phases, which is essential for interpreting electrification under different electricity sourcing assumptions. The TEA component evaluates total cost of ownership under EU ETS and FuelEU Maritime boundary conditions, explicitly testing whether policy-internalised economics invert rankings relative to fuel-only comparisons. This logic is closely aligned with comparative maritime TEA studies showing that fuel cost, propulsion efficiency, storage, infrastructure, and utilisation all shape total ownership cost across alternative ship pathways (Korberg et al., 2021).

Paper II (farm hydrogen) uses TEA to evaluate decentralised hydrogen production and refuelling feasibility through NPV and LCOH under baseline and improved utilisation scenarios. The design directly tests the dominant mechanism emphasised in the hydrogen TEA literature: capacity factor and electricity price as first-order LCOH determinants (Aminaho et al., 2025; Brynolf et al., 2018). Because this mechanism is shared with broader hydrogen and electrofuel supply chains, the paper's results are interpreted as evidence about utilisation feasibility conditions rather than as a farm-only conclusion. The methodological relevance of this framing is also supported by agricultural electrification literature, which highlights the difficulty of matching seasonal machinery demand with infrastructure-intensive energy systems (Stakens et al., 2023).

Paper IV (off-road vehicles under quarry duty) integrates TEA and LCA using a work-based functional unit (tonnes moved), enabling service-equivalent comparison across diesel, BEV, and hydrogen pathways. It explicitly models duty cycle and evaluates infrastructure deployment structure and policy-boundary choices. This is consistent with off-road review literature emphasising duty-cycle realism and the importance of site infrastructure and utilisation as adoption gates (Un-Noor et al., 2022; Pesonen et al., 2025; Antila et al., 2025). It is also methodologically consistent with wider heavy-duty transition assessments, which recommend that environmental and economic comparisons include the infrastructure requirements associated with alternative powertrain configurations (Seemungal et al., 2021).

3.5 Synthesis rules

Cross-paper synthesis is governed by four rules designed to prevent false comparability. First, every comparative claim must state the relevant analytical boundary (TTW/WTT/WTW/WtP) to avoid tailpipe-only bias and to remain aligned with lifecycle-oriented policy frameworks (European Commission, 2025; DNV, 2025a; European Union, 2023). Second, functional units are not converted post hoc across sectors; instead, the synthesis operates through recurring

mechanisms and conditional relationships rather than numerical aggregation. Third, policy boundaries are treated as part of the decision context wherever they materially affect pathway competitiveness, particularly in shipping compliance mechanisms and carbon-cost boundary testing. Fourth, uncertainty is preserved in the form used by each paper, either through scenario-based analysis where the decision context is structural or through parametric variation where the principal uncertainty concerns cost, utilisation, or technical performance.

These rules allow the synthesis to preserve the contextual integrity of the individual studies while still identifying recurring conditions that influence pathway feasibility across different empirical settings. Rather than imposing a common numerical ranking, the cross-paper analysis therefore tracks recurring mechanisms related to upstream energy conditions, infrastructure availability and utilisation, fuel-supply-chain maturity, policy and accounting boundaries, and operational constraints. From this comparison, five analytical dimensions are used to organise the synthesis: upstream electricity integrity; infrastructure availability and utilisation; hydrogen and synthetic-fuel supply-chain maturity; policy and accounting boundaries; and operational-envelope constraints.

The purpose of these dimensions is not to homogenise the results of the appended papers, but to provide a consistent basis for interpreting why pathways perform differently under different sectoral and operating conditions. In this sense, the methodological contribution of the kappa lies in preserving differences in system boundaries, functional units, and decision contexts while identifying mechanisms that recur across the four studies. Chapter 5 builds on these analytical dimensions by examining how they interact across the empirical cases and formalising them as the adoption-gates framework.

Chapter 3 summary

Key takeaways: LCA and TEA are used as complementary methods: LCA establishes lifecycle credibility under explicit boundaries and functional units, while TEA evaluates cost, utilisation, infrastructure, and investment conditions. The appended studies retain their native analytical structures, and cross-paper synthesis therefore proceeds through recurring mechanisms rather than numerical harmonisation. These principles provide the reporting basis for the empirical results in Chapter 4.

Chapter 4

Results

This chapter presents the principal findings of the four appended publications and highlights the evidence relevant to the research questions. The results are reported according to the methodological and synthesis principles established in Chapter 3, with emphasis on the main quantitative outcomes and the conditions that explain differences in pathway performance. Together, these findings provide the empirical basis for the cross-sector discussion in Chapter 5.

4.1 How results are reported

The chapter preserves *unit discipline*: results are not converted across papers into a single metric, because doing so would require additional assumptions and could create false comparability across sectors. Instead, the synthesis is expressed through *decision-conditional* findings, that is, "if–then" conclusions that remain valid under the stated boundary, functional unit, and scenario assumptions.

This reporting logic is particularly important under lifecycle-oriented transition policy. In shipping, methane slip and upstream fuel chains can erase apparent tailpipe CO_2 advantages and alter compliance outcomes under broader fuel-cycle accounting (Pavlenko et al., 2020; Kuittinen et al., 2024; European Union, 2023). In electrification, environmental performance depends strongly on electricity sourcing, infrastructure integration, and route suitability (Perčić et al., 2022; Kanchiralla et al., 2025; Seithe et al., 2020). In hydrogen systems, utilisation and electricity price dominate levelised cost and therefore investment plausibility (Aminaho et al., 2025; Brynolf et al., 2018). The results are therefore organised to make these dependencies explicit rather than to collapse them into a single cross-sector ranking.

4.2 Paper I: short-sea roadmap (WtP; MRV-style transport work)

Paper I applies life-cycle thinking from well-to-propeller (WtP), i.e. well-to-tank (WtT) plus tank-to-propeller (TtP), and reports MRV-relevant performance metrics. Emissions per transport work are expressed as grams CO_2 per passenger transport work (gCO_2/pax-nm) and grams CO_2 per cargo transport work (gCO_2/ton-nm), using mass allocation between passenger and cargo services.

Across scenarios, marine diesel oil (MDO) shows the highest fuel consumption per nautical mile (kg/nm), reported as approximately 10–12% higher than the other scenarios due to its lower calorific value. The paper also finds that fuel consumption per ton-nm is about twice fuel consumption per pax-nm, which follows from the transport-work allocation. Mass allocation ranges around 87–87.5% to cargo and 13–12.5% to passenger transport work over 2023–2050, yielding a higher burden for cargo service. The operator's trajectory plan for efficiency improvement reduces fuel consumption per transport work from 2023 to 2050 by about 45% for passenger transport work and 51% for cargo transport work across all scenarios.

This result is important because it shows that part of the observed improvement is operational rather than fuel-specific: the roadmap pathways are evaluated against an improving service system rather than against a static vessel-performance assumption. In this respect, Paper I captures both fuel substitution and service-efficiency improvement, which is consistent with the dissertation's broader argument that pathway performance is shaped jointly by fuel choice, operational pattern, and boundary definition.

MDO exhibits the highest CO_2 emissions per distance, followed by LNG, LNG&LBG, and LBG. Switching from MDO to LNG reduces CO_2 emissions by about 25% compared with MDO, but the overall climate-change impact is not significantly lower once methane is included, because LNG has higher CH_4 emissions due to methane slip. This mechanism is consistent with the LNG lifecycle literature (Pavlenko et al., 2020; Kuittinen et al., 2024). Contribution analysis indicates that TtP accounts for about 83.7% and 84.2% of total carbon emissions for MDO and LNG, respectively, while LBG shows the opposite pattern, with upstream WtT responsible for about 68% of total carbon emissions because combustion CO_2 is treated as biogenic. For climate-change impact (characterisation factors CH_4=25 and N_2O=298), CO_2 dominates in MDO and LNG, while CH_4 is the main contributor in LBG; CH_4 contributes about 31% (LNG&LBG) and 54% (LBG) of total climate-change impact.

The substantive implication is that carbon accounting at the fuel-combustion level alone would misrepresent pathway performance. Paper I therefore reinforces a core thesis finding: apparent TTW gains do not necessarily translate into robust WtP or WTW climate benefits when methane-related effects are material.

Paper I projects fuel and carbon costs under three carbon-tax schemes (STEPS, SDS, NZE) and low/high fuel price cases. Table 4.1 reproduces the paper's reported annual fuel and carbon

cost totals (Table 5 in the article), in euros.

Table 4.1: Paper I: Summary of annual fuel and carbon costs (€, Table 5 in the article).

Year	Cost item	MGO/MDO		LNG		LNG&LBG		LBG	
		Low	High	Low	High	Low	High	Low	High
2023	Fuel	3,430,244	4,652,953	3,487,589	5,998,329	3,489,982	6,007,341	3,873,391	7,451,308
2023	STEPS	0	0	0	0	0	0	0	0
2023	SDS	0	0	0	0	0	0	0	0
2023	NZE	0	0	0	0	0	0	0	0
2030	Fuel	2,755,446	3,737,624	2,110,536	3,616,937	2,506,844	4,631,479	2,890,616	5,613,931
2030	STEPS	970,249	970,249	875,475	875,475	609,773	609,773	352,475	352,475
2030	SDS	1,791,229	1,791,229	1,616,261	1,616,261	1,125,734	1,125,734	650,722	650,722
2030	NZE	1,940,498	1,940,498	1,750,950	1,750,950	1,219,545	1,219,545	704,949	704,949
2050	Fuel	1,393,042	2,583,869	1,136,898	2,156,973	2,087,720	4,228,394	2,133,008	4,327,057
2050	STEPS	1,215,273	1,215,273	1,096,565	1,096,565	471,271	471,271	441,488	441,488
2050	SDS	2,700,607	2,700,607	2,436,812	2,436,812	1,047,269	1,047,269	981,084	981,084
2050	NZE	3,375,759	3,375,759	3,046,015	3,046,015	1,309,086	1,309,086	1,226,355	1,226,355

The table shows that pathway ordering is not stable over time. In the early years, fuel-price assumptions dominate much of the cost difference across pathways, but by 2030 and especially by 2050 the carbon-cost component becomes increasingly important. This means that long-run competitiveness depends not only on fuel prices, but also on how strongly policy-internalised carbon costs penalise higher-intensity pathways. The result is consistent with the dissertation's earlier framing of adoption in shipping: policy boundary and upstream integrity shape competitiveness, not only onboard energy efficiency.

Paper I further translates fuel and carbon cost changes into passenger price exposure using a ratio method anchored to observed ticket prices and the share of fuel costs in total operating costs. The key interpretive result is that compliance cost can dominate the long-run ordering of pathways: under high carbon-cost trajectories, relative cost positions can reverse, so that conventional fuels become the most expensive by 2050 even where early-period fuel-price assumptions appear favourable. Read together, the transport-work results, lifecycle emissions, and cost projections show that pathway selection in short-sea shipping remains conditional on both upstream performance and policy exposure. In this sense, Paper I provides direct quantitative support for the thesis argument that roadmap fuels should be interpreted through lifecycle and compliance boundaries rather than through tailpipe emissions or fuel price alone.

Adoption implication. Paper I supports the lifecycle boundary and policy-accounting gates. The results show that LNG and LBG pathways cannot be evaluated credibly through combustion CO_2 alone because methane slip and upstream fuel-chain assumptions materially affect climate performance. The paper therefore demonstrates why fuel-switching pathways require WTW-compatible accounting and verified upstream fuel integrity before they can be considered robust transition options.

4.3 Paper II: decentralised farm hydrogen (NPV; LCOH)

Paper II is a techno-economic study reporting Net Present Value (NPV, €) and levelised cost of hydrogen (LCOH, €/kg H_2) under scenario definitions that vary electrolyser utilisation and electricity price assumptions. The core decision question is whether decentralised hydrogen production for agricultural machinery can become economically plausible under observed baseline demand and under improved utilisation conditions.

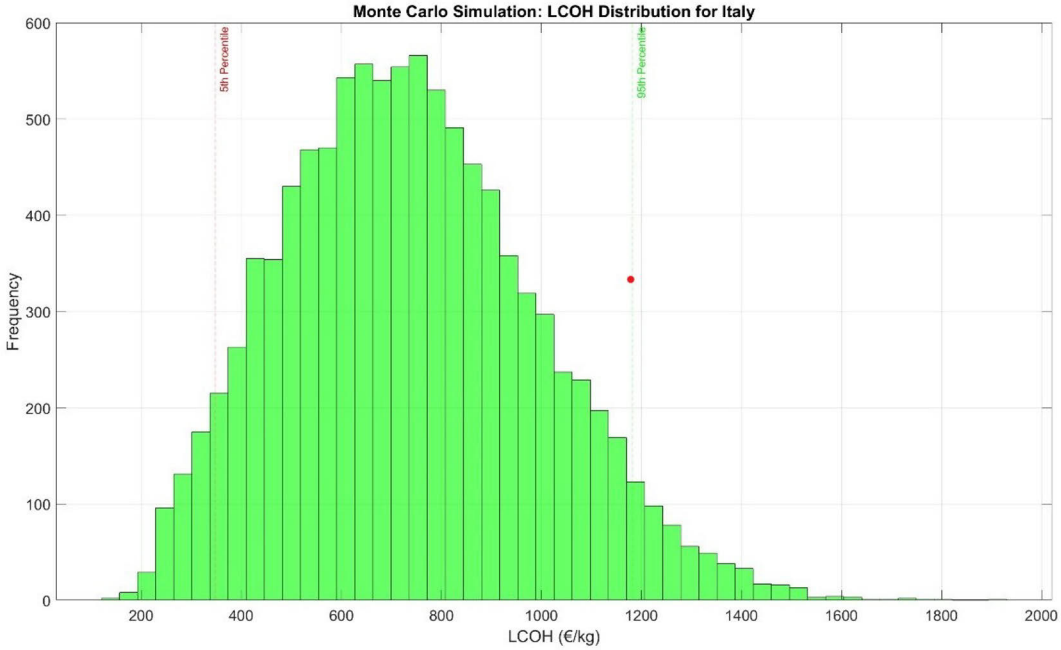
The baseline hydrogen-demand-for-machinery model reports negative NPV across all studied countries, indicating non-viability under the stated conditions. LCOH varies widely: Italy has the highest LCOH (57.4 €/kg H_2) and the United States the lowest (10.9 €/kg H_2). The dominant mechanism is utilisation: low capacity factor spreads fixed-capital costs over too few kilograms of hydrogen, which is consistent with TEA synthesis showing electricity price and capacity factor as dominant LCOH drivers (Aminaho et al., 2025; Brynolf et al., 2018).

Table 4.2: Paper II: Results of the first economic model (HDP baseline; Table 10 in the article).

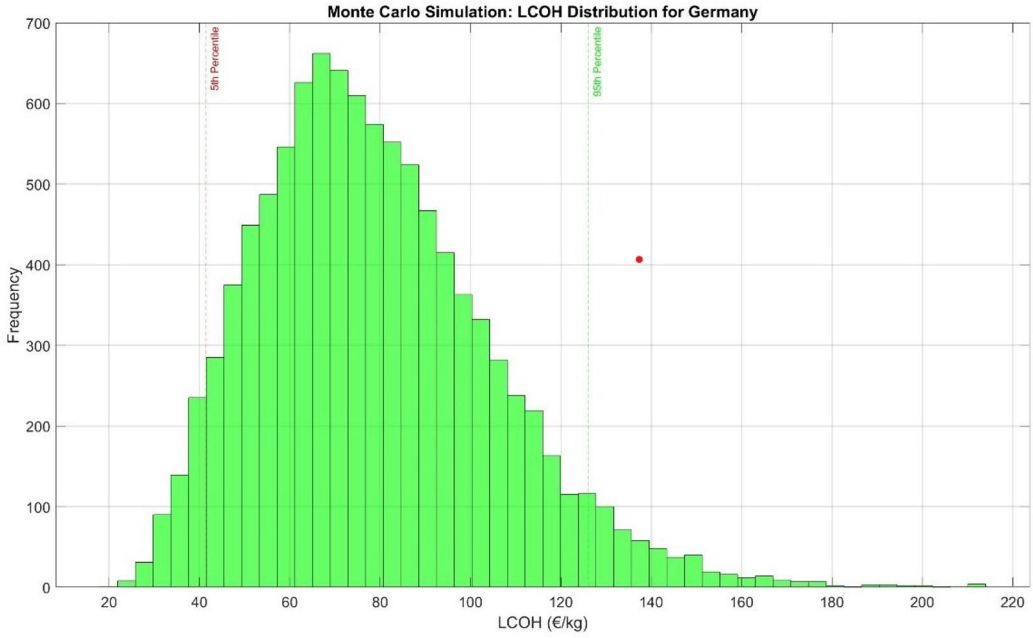
Country	Utilisation rate (%)	Load hours (HDP)	NPV (HDP) (€)	LCOH (HDP) (€/kg)
Italy	7.6	667	-555,575.0	57.4
Germany	26.9	2,355	-2,415,481.5	22.3
Sweden	26.0	2,280	-1,521,762.1	21.8
United States	61.4	5,382	-4,525,573.5	10.9

The baseline table already makes the central mechanism visible. The United States case benefits from the highest utilisation and the lowest LCOH, while Italy combines the lowest utilisation with the highest LCOH. Germany and Sweden occupy an intermediate position. This pattern supports the dissertation's broader claim that decentralised hydrogen viability is not determined by hydrogen demand alone, but by how electricity cost, utilisation, and capital recovery interact.

To complement the deterministic baseline results, Monte Carlo simulations were used to examine the dispersion of LCOH outcomes under uncertainty in the underlying economic assumptions. The resulting distributions remain positively skewed across the reported cases, indicating that while central outcomes cluster around the expected LCOH range, upside cost risk remains material. This is particularly visible in the Italy case, where the distribution is broad and shifted toward higher LCOH values, reflecting the strong sensitivity of decentralised hydrogen economics to adverse combinations of electricity price, utilisation, and capital recovery. Germany and Sweden show lower central values than Italy but still retain pronounced right tails, confirming that apparently favourable average values do not eliminate exposure to high-cost outcomes. The United States remains the lowest-cost case in central tendency, although uncertainty remains non-negligible.

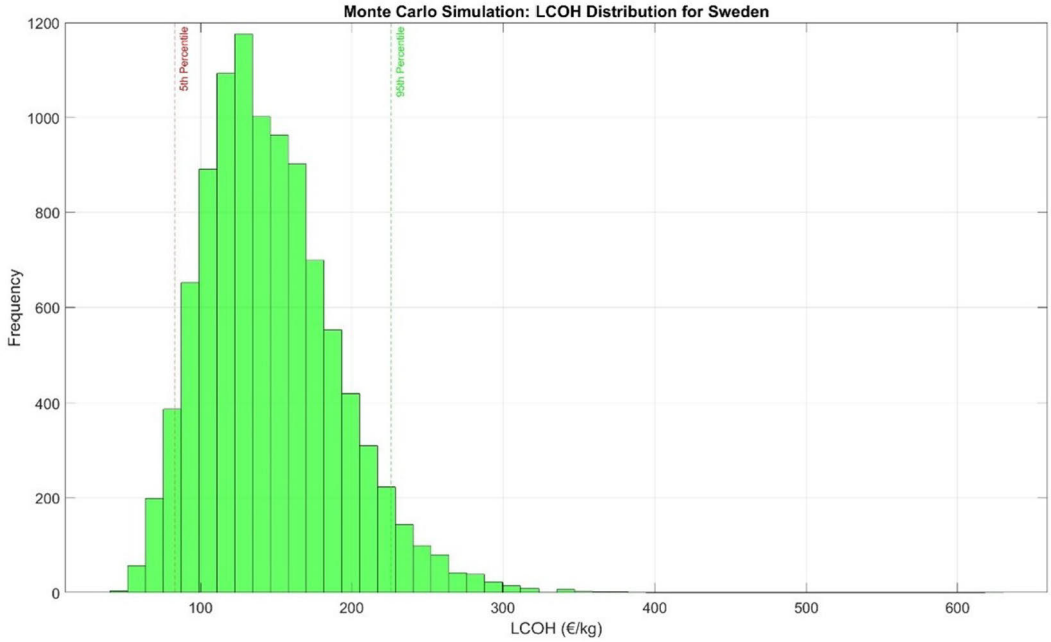


(a) Italy

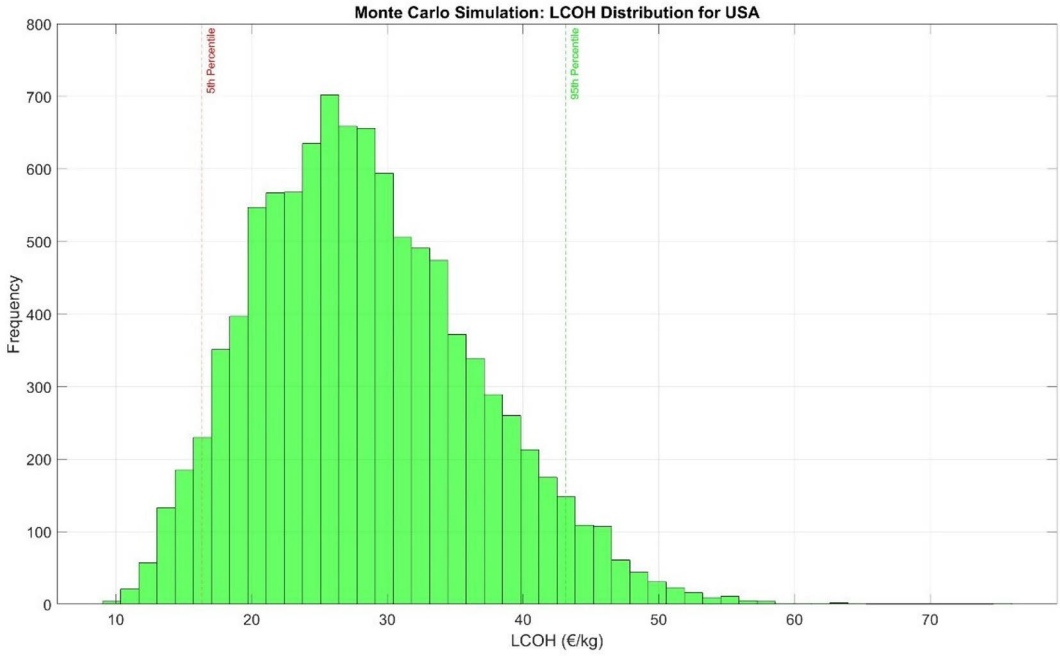


(b) Germany

Figure 4.1: Monte Carlo distributions of LCOH outcomes for Paper II under the sensitivity-analysis assumptions (Part 1).



(c) Sweden

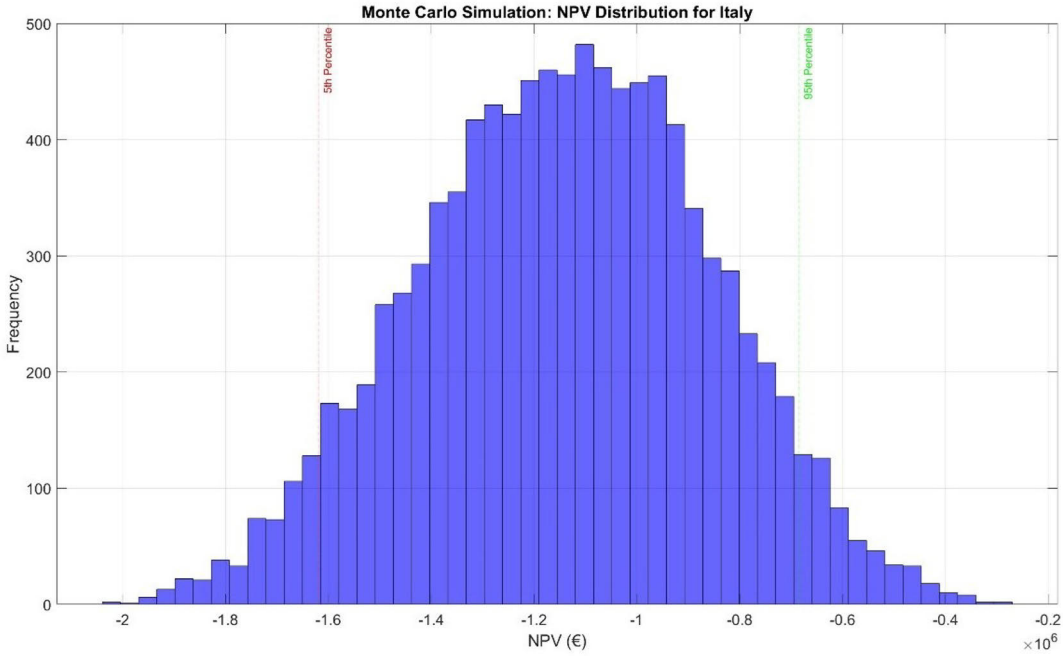


(d) United States

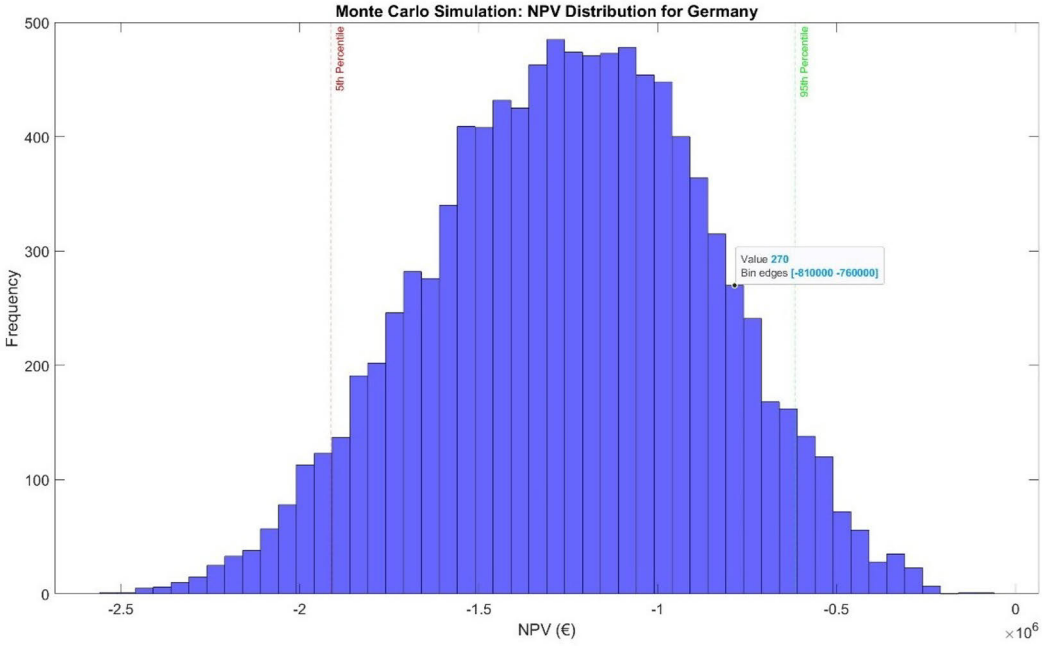
Figure 4.1: Monte Carlo distributions of LCOH outcomes for Paper II under the sensitivity-analysis assumptions (Part 2). Across all cases, the distributions are right-skewed, indicating persistent upside cost risk even where central estimates are lower.

These distributions do not replace the baseline results in Table 4.2; rather, they qualify them by showing that deterministic LCOH values sit inside wider cost distributions. The implication is that favourable point estimates alone are insufficient for investment interpretation if the pathway remains exposed to substantial upper-tail cost risk.

The Monte Carlo analysis for NPV reinforces the same conclusion from a project-viability perspective. Across all countries, the simulated NPV distributions remain concentrated in negative territory, confirming that the baseline decentralised hydrogen concept is structurally non-viable under the assumed farm-demand conditions. However, the width and location of the distributions vary by country. Italy and Germany show broad negative ranges, Sweden remains clearly negative but somewhat less dispersed, and the United States exhibits the widest spread and the greatest proximity to break-even in its upper tail. This suggests that the United States case is relatively more responsive to favourable combinations of utilisation and cost assumptions, even though the baseline expectation remains negative. The distributions therefore support the thesis argument that decentralised hydrogen viability is not simply a matter of mean LCOH, but of whether utilisation and electricity procurement are strong enough to shift the broader project-value distribution toward acceptable investment outcomes.

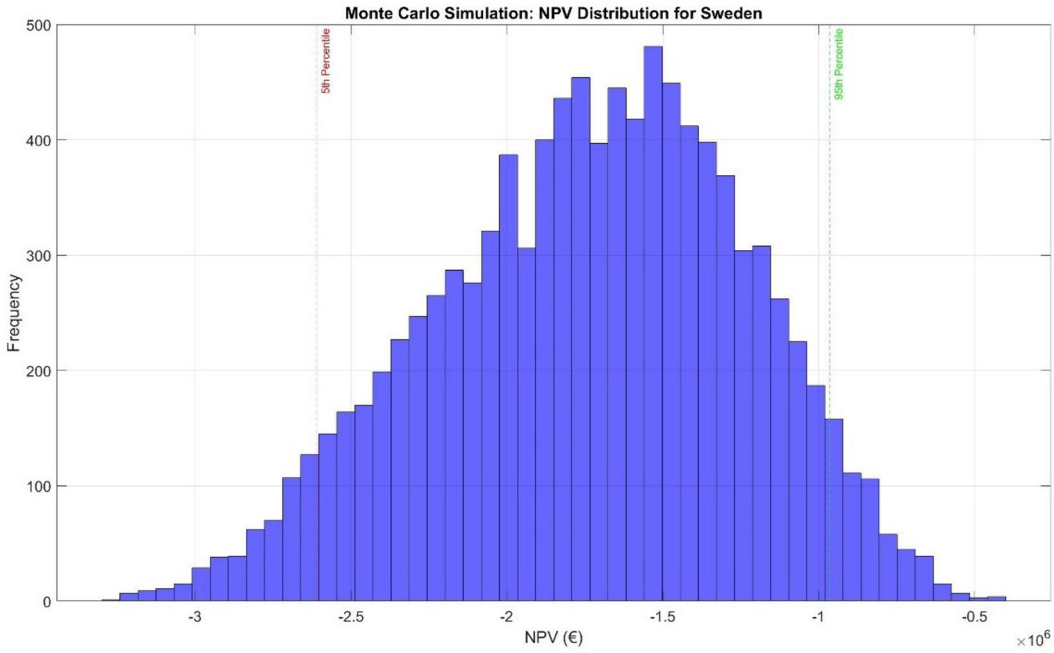


(a) Italy

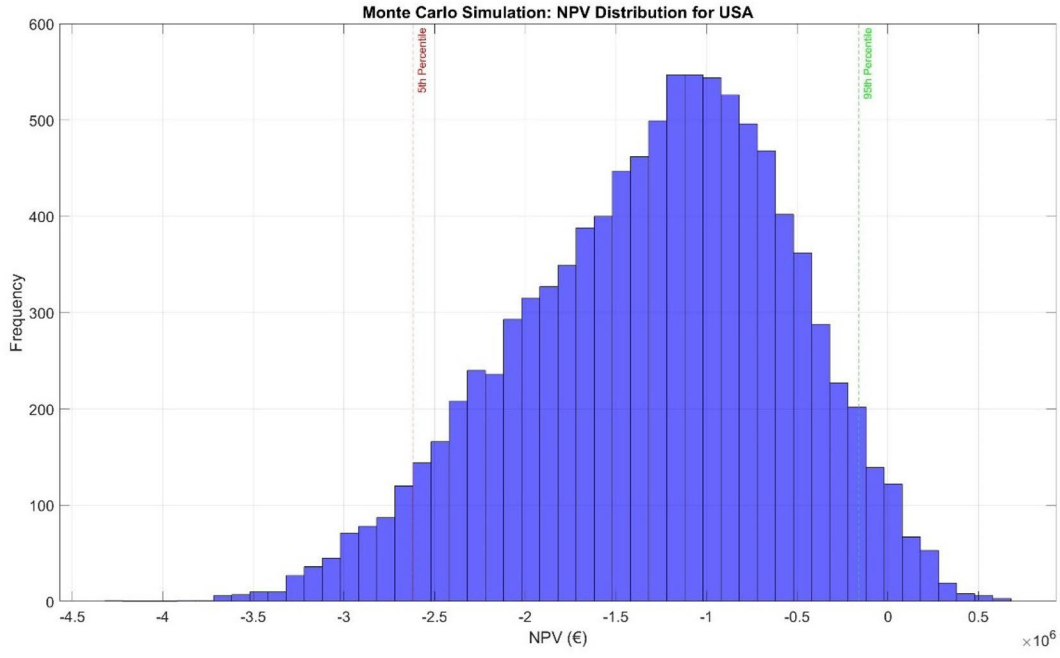


(b) Germany

Figure 4.2: Monte Carlo distributions of NPV outcomes for Paper II under the sensitivity-analysis assumptions (page 1 of 2).



(c) Sweden



(d) United States

Figure 4.2: Monte Carlo distributions of NPV outcomes for Paper II under the sensitivity-analysis assumptions (page 2 of 2). In all cases, the distributions remain predominantly negative, indicating persistent project non-viability under baseline decentralised demand conditions, although the upper tail is comparatively stronger in the United States case.

Again, these Monte Carlo distributions are best interpreted as complements to the baseline values rather than substitutes for them. Table 4.2 establishes the deterministic project outlook under the stated assumptions, while Figures 4.1 and 4.2—each presented across two pages—show how uncertainty propagates through those assumptions and preserves predominantly negative investment outcomes across the sampled cases.

The second model explores increased utilisation (for example, to 70%) and by-product revenue offsets. The paper reports that increasing utilisation materially reduces LCOH across all countries and that revenue offsets can further improve results, but also emphasises that market access for excess hydrogen and by-products remains a feasibility condition rather than an automatic benefit. Read together, the deterministic and Monte Carlo results show that decentralised hydrogen remains structurally constrained under baseline farm-only demand, while improved utilisation is the main lever capable of shifting both cost and project-value outcomes toward plausibility.

At the kappa level, Paper II establishes a transferable adoption mechanism: decentralised hydrogen becomes more plausible when utilisation can be enhanced through aggregation or additional offtake and when electricity procurement is sufficiently favourable. In this context, the farm case should be interpreted not only as a sector-specific result but also as evidence of a broader distributed-hydrogen constraint: low utilisation not only raises the average levelised cost of hydrogen (LCOH) but also increases uncertainty, resulting in persistently negative investment returns.

Adoption implication. Paper II supports the infrastructure-utilisation and upstream-energy gates. The decentralised hydrogen scenario demonstrates that while technical feasibility exists, it does not equate to economic viability under conditions of low utilisation and high electricity prices. Thus, hydrogen adoption in distributed agricultural settings relies on demand aggregation, favourable electricity procurement, and adequate capacity factor.

4.4 Paper III: battery-electric short-sea benchmark (WTW; 30-year route)

Paper III reports well-to-wake (WTW) environmental results for a 30-year operational lifetime on the Helsinki–Tallinn route, expressed in tonnes CO_2-equivalent (tCO_2-eq) for Tier 1 (GWP_{100}). It also reports WTW greenhouse gas intensities (gCO_2e/MJ) for key pathways. Techno-economic results are expressed as total cost of ownership or net present cost style comparisons under EU ETS and FuelEU Maritime boundary conditions. When powered by 100% renewable electricity, the battery-electric RoPax has the lowest WTW climate impact (61,881 tCO_2-eq over 30 years), compared with approximately 1.69 million tCO_2-eq for marine gas oil and 1.67 million tCO_2-eq for LNG. Using the current Finnish–Estonian grid mix increases emissions by more than an order of magnitude, illustrating that electrification outcomes are fundamentally upstream-dependent.

This mechanism is consistent with route-level electrification benchmarks and maritime lifecycle literature showing that vessel performance, electricity sourcing, and operational context must be assessed together (Perčić et al., 2022; Kanchiralla et al., 2025; Seithe et al., 2020).

Table 4.3: Paper III: Tier-1 WTW GWP_{100} results over 30 years (tCO_2-eq), as reported in the paper abstract.

Pathway	WTW GWP_{100} (tCO_2-eq over 30 years)
Battery-electric (100% renewable electricity)	61,881
Marine gas oil	1,690,000
Liquefied natural gas	1,670,000
Liquefied biogas	955,342
Renewable e-methanol	348,446

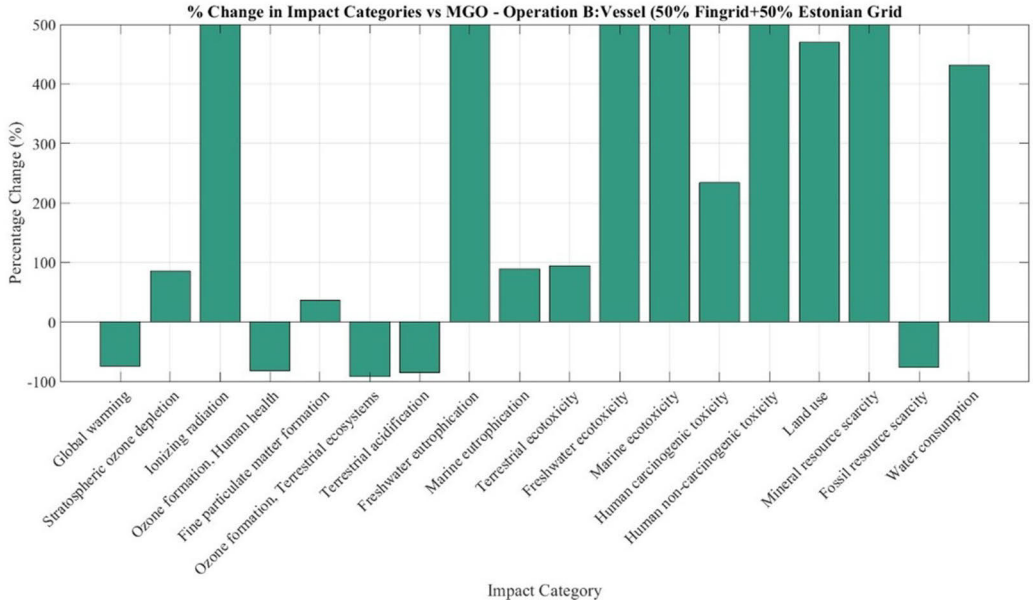
The paper reports total WTW intensities (gCO_2e/MJ) for principal pathways: 90.6 for MGO, 90.99 for LNG, 46.91 for LBG, 45.84 for synthetic methanol, and 0 for electricity as the main onboard energy carrier.

Table 4.4: Paper III: Reported WTW GHG intensities (gCO_2e/MJ), total WTW values.

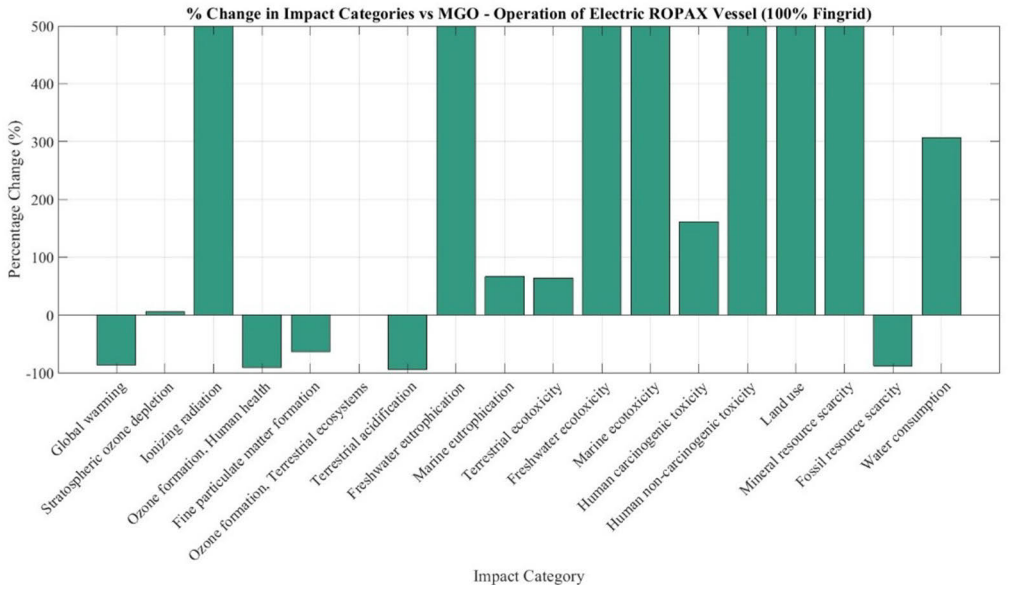
	MGO	LNG	LBG	Synthetic methanol	Electric
Total WTW (gCO_2e/MJ)	90.6	90.99	46.91	45.84	0

The climate results above identify the dominant greenhouse-gas ranking of the pathways, but they do not on their own show whether improvements in climate performance coincide with improvements across other environmental categories. For this reason, the appendix analysis of other impact categories is also relevant to the interpretation of Paper III. These supplementary results compare the percentage change from the MGO baseline when switching to a battery vessel under a mixed grid, a battery vessel under a low-carbon grid, an LNG vessel, an LBG vessel, and an e-methanol vessel. Taken together, these figures help distinguish pathways that are robustly favourable across a broader environmental profile from those whose climate performance may improve while other impact categories remain mixed or shift upstream. This is particularly important for battery-electric operation, where the environmental outcome remains strongly dependent on electricity sourcing, and for renewable fuel pathways, where upstream production chains influence impacts beyond GWP (Seithe et al., 2020; Korberg et al., 2021).

The appendix identifies these five comparison figures explicitly as Figure A1 to Figure A5 (in this case figure 5.3 and fig 5.4.

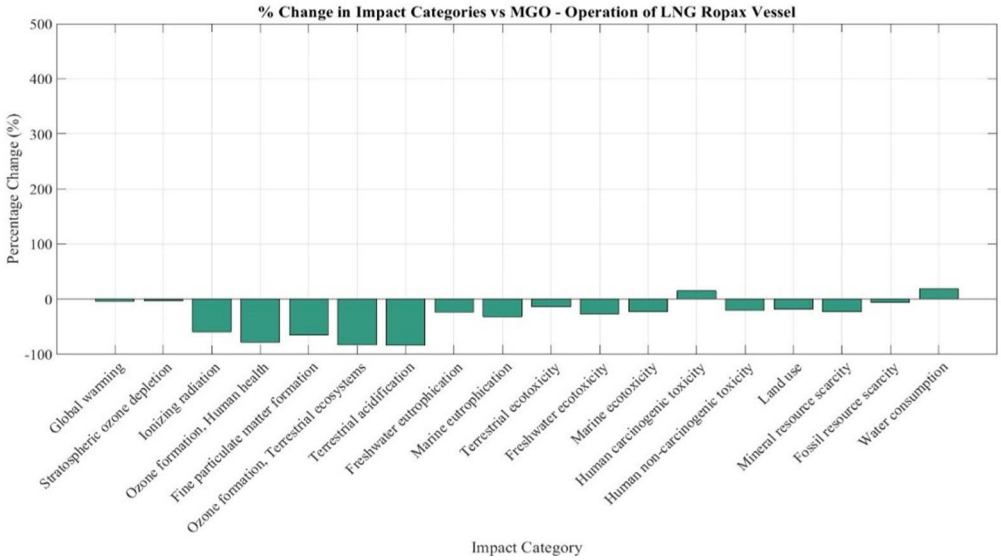


(a) Percentage change when switching from MGO to a battery vessel under mixed-grid electricity.

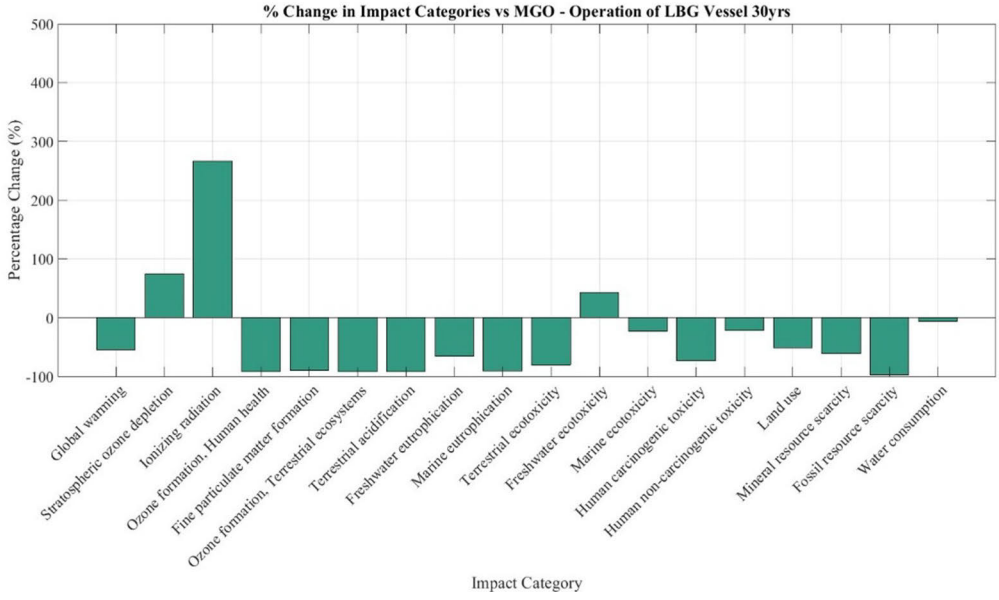


(b) Percentage change when switching from MGO to a battery vessel under low-carbon electricity.

Figure 4.3: Supplementary comparison of other impact categories in Paper III relative to the MGO baseline: (a) battery vessel under mixed-grid electricity and (b) battery vessel under low-carbon electricity. These figures supplement the main WTW climate tables by showing how battery-pathway performance differs across a broader environmental profile depending on electricity sourcing.

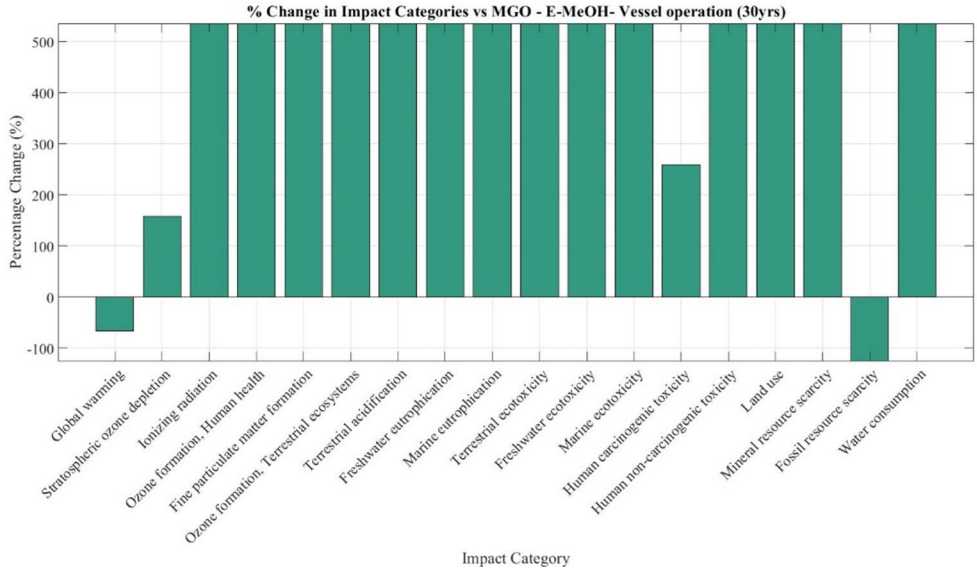


(a) Percentage change when switching from MGO to an LNG vessel.



(b) Percentage change when switching from MGO to an LBG vessel.

Figure 4.4: Supplementary comparison of other impact categories in Paper III relative to the MGO baseline (page 1 of 2).



(c) Percentage change when switching from MGO to an e-methanol vessel.

Figure 4.4: Supplementary comparison of other impact categories in Paper III relative to the MGO baseline (page 2 of 2). These figures extend the main climate findings by showing how alternative fuel pathways influence a wider set of environmental impact categories.

The supplementary impact-category figures are especially useful for interpreting the battery pathway. Figures 4.3a and 4.3b show that the environmental advantage of electrification is not invariant: the magnitude and breadth of improvement depend on whether charging electricity is drawn from a mixed grid or from a low-carbon supply. Likewise, Figures 4.4a–4.4c—presented across two pages—clarify that moving away from MGO may improve climate performance while leaving other impact categories more mixed, depending on upstream production, fuel processing, and system integration. In this sense, the appendix figures reinforce the dissertation's boundary-explicit stance by illustrating that pathway evaluation should not rely on climate indicators alone where broader environmental trade-offs may be relevant.

Paper III highlights that although the battery-electric vessel has higher capital costs, including battery packs over lifetime, it becomes the most economic option once EU ETS and FuelEU mechanisms are included, because all-electric operation avoids allowance purchases and can benefit from FuelEU pooling effects. The decision-conditional conclusion is therefore that electrification dominates on short, frequent routes *if* port infrastructure is available and *if* electricity procurement is low-carbon. Otherwise, both environmental and economic performance can move closer to other lower-carbon fuel pathways.

This is one of the clearest examples in the dissertation of policy-boundary internalisation changing pathway ranking. Fuel-only or TTW comparisons would not capture the same result. Paper III therefore directly supports the thesis argument that WTW accounting, electricity sourcing, and infrastructure readiness jointly determine pathway feasibility.

Adoption implication. Paper III supports the operational-envelope and infrastructure-readiness gates. The battery-electric RoPax pathway becomes credible where route length, charging windows, port power, and electricity sourcing align. The result demonstrates that electrification is not a universal maritime solution, but a strong pathway in short-sea services with repeated port calls and adequate shore-side infrastructure.

4.5 Paper IV: off-road quarry duty (work-based LCIA; RA–TCO)

Paper IV evaluates diesel, battery-electric (BEV), and fuel-cell electric (FCEV) wheel-loader pathways under Nordic quarry conditions using a work-based analytical framework. Environmental results are reported as life-cycle greenhouse-gas emissions per productive output (kg CO_2-eq t^{-1} moved), while economic results are reported as relative-adjusted total cost of ownership (RA–TCO, t^{-1} moved), complemented by net present cost and uncertainty analysis. This work-based normalisation is central to the interpretation of the paper because it allows environmental and economic comparison on the basis of delivered service rather than machine-hours or fuel consumption alone.

Figure 4.5 reports life-cycle greenhouse-gas emissions per unit of productive output across

Finland, Sweden, Norway, and Denmark. Across all countries, diesel wheel loaders exhibit the highest life-cycle emissions, with use-phase fuel combustion accounting for the dominant share. Despite compliance with Stage V pollutant regulation, the climate performance of the diesel pathway remains structurally coupled to fuel throughput, producing a relatively stable but high-emission baseline across all country cases.

Battery-electric wheel loaders show the lowest work-normalised life-cycle emissions in all Nordic countries. Under the low-carbon electricity systems of Norway, Sweden, and Finland, operational emissions remain close to zero and total life-cycle emissions remain far below diesel even after manufacturing burdens are included. Overall, the BEV pathways avoid approximately 1.2–1.3 kg CO_2-eq per tonne moved relative to diesel. This confirms the central environmental conclusion of Paper IV: in high-utilisation quarry duty, electrification shifts emissions upstream to manufacturing and electricity supply, but those added burdens remain small relative to the avoided diesel combustion burden under low-carbon grids.

Fuel-cell pathways show a more contingent pattern. In Norway, where electricity used for hydrogen production is predominantly renewable, the FCEV pathway reduces life-cycle emissions relative to diesel, reaching approximately 0.27 kg CO_2-eq t^{-1} moved. In Denmark, however, upstream emissions from electricity-intensive hydrogen production dominate the result, causing the total FCEV pathway to perform substantially worse than diesel. The Denmark case therefore illustrates one of the strongest cross-paper mechanisms in the dissertation: upstream integrity can invert the apparent attractiveness of an end-use technology when the supply chain is electricity-intensive.

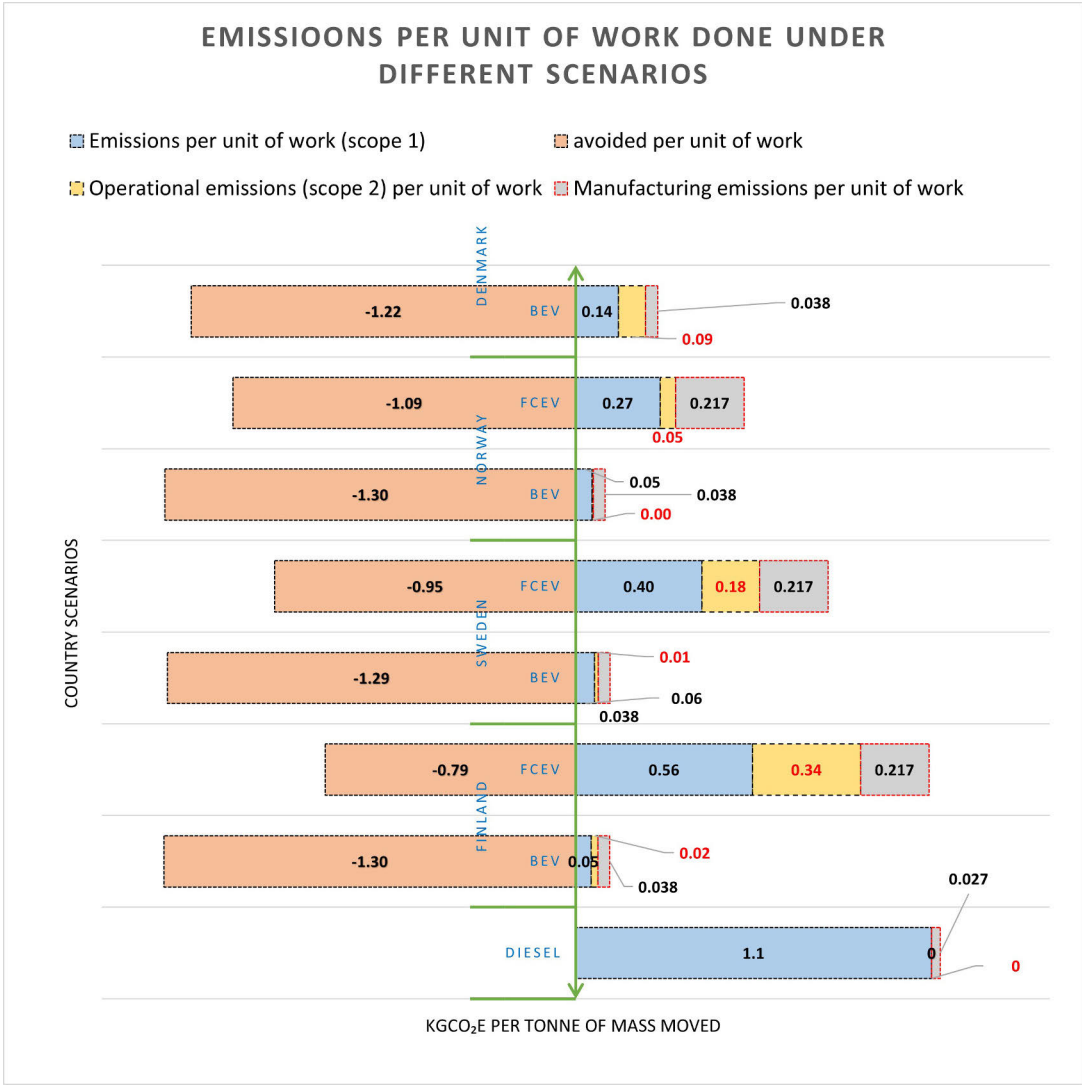


Figure 4.5: Life-cycle greenhouse-gas emissions normalised to productive output (kg CO_2-eq t^{-1} moved) for diesel, battery-electric, and fuel-cell electric wheel loaders across Nordic countries.

The work-normalised LCIA results are particularly important for the kappa because they show that pathway comparison is only meaningful when expressed against delivered output. This is fully consistent with the methodological stance of the dissertation and with the off-road literature, which emphasises duty-cycle realism and service-based comparison.

The economic results of Paper IV show that the environmental advantage of electrification is not offset by a corresponding cost penalty under Nordic quarry conditions. Under diesel-stress assumptions, diesel wheel loaders exhibit the highest average RA–TCO, approximately 0.41 t^{-1} moved. Both BEV configurations are cost-competitive without additional technology-specific support in the Nordic context, with average RA–TCO of approximately 0.32 t^{-1} moved for BEV_3500C and 0.27 t^{-1} moved for BEV_6000C. These values indicate that high drivetrain efficiency, relatively low electricity-related carbon exposure, and the work-normalised structure of the duty cycle combine to make battery-electric operation economically credible in addition to environmentally favourable.

Hydrogen pathways remain substantially more expensive. FCEV_RE reaches approximately 0.91 t^{-1} moved, while FCEV_SMR and FCEV_SMR+CCS are approximately 0.67 and 0.73 t^{-1} moved, respectively. In the hydrogen cases, fuel cost remains the dominant cost component, indicating that the economic constraint lies less in the vehicle platform itself than in the cost and upstream structure of delivered hydrogen.

Table 4.5: Paper IV: Key work-normalised results reported in the publication (unit-consistent summary).

Metric	Reported value(s)	Unit
BEV Scope 2 (FI/SE/NO)	<~0.06	kg CO_2-eq t^{-1} moved
BEV life-cycle (incl. manufacturing)	~0.04	kg CO_2-eq t^{-1} moved
Avoided vs diesel (BEV)	~1.2–1.3	kg CO_2-eq t^{-1} moved
FCEV life-cycle (Norway)	~0.27	kg CO_2-eq t^{-1} moved
FCEV life-cycle (Denmark)	~16× diesel	(ratio; WTW basis)
Diesel RA–TCO (diesel-stress)	~0.41	€ t^{-1} moved
BEV RA–TCO (no policy)	0.32 (3500C); 0.27 (6000C)	€ t^{-1} moved
FCEV RA–TCO (no policy)	0.91 (RE); 0.67 (SMR); 0.73 (SMR+CCS)	€ t^{-1} moved
BEV RA–TCO (policy)	~0.23 (3500C); ~0.26 (6000C)	€ t^{-1} moved
FCEV RA–TCO (policy)	0.67 (RE); ~0.65–0.66 (SMR cases)	€ t^{-1} moved

Table 4.5 anchors the main numerical findings and shows that the environmental and economic ranking move in the same direction under Nordic quarry conditions: BEVs are both lower-emission and lower-cost than diesel and hydrogen in the main cases reported. The table also makes visible the asymmetry between BEV and hydrogen pathways under policy support: battery-electric systems improve further from an already competitive position, whereas hydrogen pathways remain relatively expensive even after favourable policy adjustments.

The supplementary Monte Carlo comparison figures add an important layer of interpretation by showing how the technologies compare under stochastic variation in productivity, cost,

replacement timing, and infrastructure utilisation. Figure 4.6 compares BEV pathways against diesel under fleet-calibrated assumptions across Nordic countries. The figure shows that BEV outcomes cluster more consistently toward lower-emission and lower-cost regions, indicating that the battery-electric pathway remains comparatively robust even when uncertainty is introduced into the main economic and technical parameters. This means that the favourable average RA–TCO and LCIA results are not driven by a narrow set of assumptions alone, but persist across a broader simulation space.

By contrast, Figure 4.7 shows that hydrogen pathways occupy a wider and less favourable distribution relative to diesel. The broader spread indicates stronger sensitivity to upstream hydrogen supply conditions, infrastructure utilisation, and fuel-cost assumptions. This wider uncertainty envelope is consistent with the earlier result that hydrogen pathways remain more contingent than BEV pathways even when they can achieve acceptable environmental outcomes under low-carbon electricity conditions.

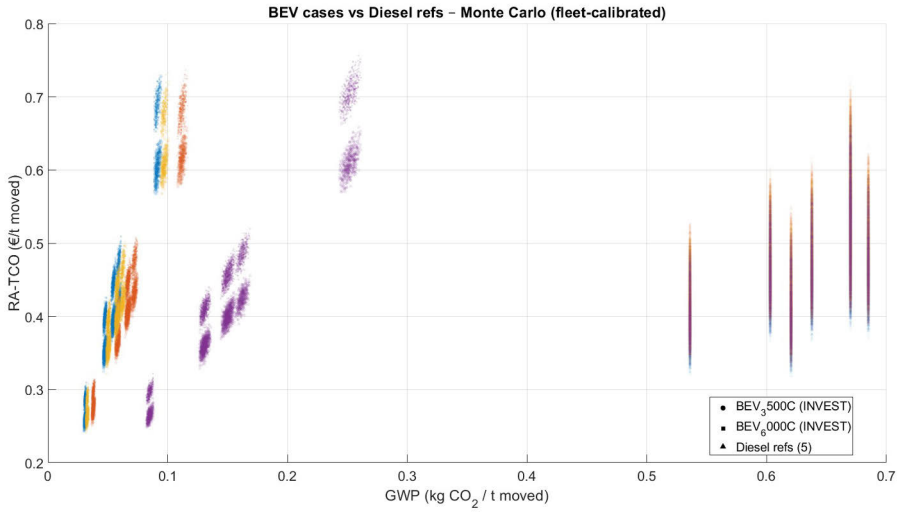


Figure 4.6: Monte Carlo comparison of BEV pathways against diesel across Nordic countries.

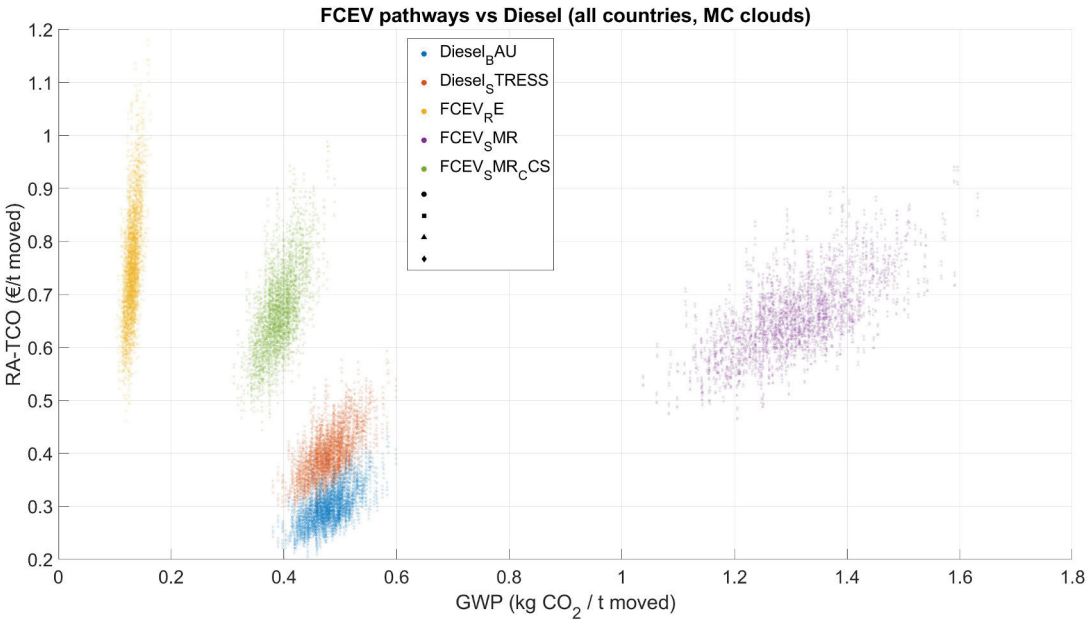


Figure 4.7: Monte Carlo comparison of hydrogen pathways against diesel across Nordic countries.

Read together, Figure 4.5, Table 4.5, and Figures 4.6–4.7 strengthen the central interpretation of Paper IV. Battery-electric deployment is not only the lowest-emission pathway on average in high-utilisation Nordic quarry duty; it also appears comparatively robust when uncertainty in cost and performance assumptions is introduced. Hydrogen, by contrast, remains a more conditional pathway whose competitiveness depends on a narrower and more demanding set of upstream and utilisation conditions.

Paper IV presents a clear set of cross-paper results within the dissertation, particularly regarding high-utilisation, site-owned, and grid-accessible off-road segments, such as those used in quarry duty. Under Nordic electricity conditions, battery-electric pathways emerge as the most favourable option both environmentally and economically. In contrast, hydrogen pathways are highly conditional; while they can reduce emissions if supported by low-carbon electricity, they face economic disadvantages and can lead to greater environmental impacts if hydrogen production relies on carbon-intensive electricity sources.

The normalised structure of the paper emphasises that the ranking of off-road pathways depends on factors such as delivered service, infrastructure utilisation, upstream energy integrity, and policy boundaries, rather than on drivetrain categories alone.

In terms of adoption implications, the findings in Paper IV advocate for a service-based comparison and focus on infrastructure utilisation. The results indicate that battery-electric machinery can outperform diesel engines when grid access, duty cycles, and machine utilisation support the high usage of both the machinery and charging infrastructure. Conversely, hydrogen's viability is more limited due to its dependence on electricity supply, conversion losses, and the

effective use of refuelling infrastructure.

Chapter 4 summary

Key takeaways: The four publications show that pathway performance changes with the conditions under which technologies are supplied, operated, and assessed. Upstream fuel and electricity characteristics, utilisation, infrastructure, route or duty-cycle requirements, and policy exposure repeatedly influence both environmental and economic outcomes. These recurring empirical relationships form the evidence base for the adoption-gates synthesis developed in Chapter 5.

Chapter 5

Adoption gates and thesis contribution

This chapter moves from the paper-specific results presented in Chapter 4 to their cross-sector interpretation. Its purpose is to identify the recurring conditions that determine whether an environmentally or economically promising pathway can progress from technical possibility to practical deployment. The analytical dimensions introduced in the methodological synthesis are therefore examined here as interacting adoption conditions across the three empirical domains. This provides the basis for the adoption-gates framework and for articulating the principal integrative contribution of the dissertation.

5.1 Empirical basis of the adoption-gates framework

The results in Chapter 4 show that the environmental and economic performance of transition pathways cannot be explained by technology choice alone. Across the appended papers, pathway credibility depends on whether these enabling conditions are met: lifecycle boundary fit, upstream energy integrity, infrastructure readiness and utilisation, policy-accounting alignment, and operational-envelope compatibility. This chapter synthesises these recurring conditions into an adoption-gates framework for hard-to-abate transition pathways.

The purpose of the framework is not to replace LCA or TEA, but to translate their results into a decision-oriented structure for assessing whether a pathway can move from technical possibility to practical deployment. In this sense, the adoption-gates framework constitutes the integrative contribution of the kappa: it explains why some pathways appear favourable under narrow assessment boundaries but become weak when upstream emissions, infrastructure constraints, utilisation limits, or policy rules are made explicit.

In hard-to-abate sectors, transitions are implemented through decisions made by multiple actors, including asset owners, operators, infrastructure providers, energy suppliers, OEMs, regulators, financiers, and, in some segments, end customers. To structure this complexity, this dissertation uses the concept of *adoption gates*: the conditions that must be sufficiently satisfied for a pathway to move from technical possibility towards practical deployment.

Across the three empirical domains, five recurring gates are identified: (G1) *upstream energy integrity*, covering the carbon intensity, cost, and production characteristics of electricity and fuel supply; (G2) *infrastructure and utilisation*, including charging, refuelling, electrolysis capacity, infrastructure sharing, and capacity factor; (G3) *alternative-fuel supply-chain maturity*, including hydrogen, synthetic fuels, renewable gaseous and liquid fuels, production routes, logistics, availability, safety, and certification; (G4) *policy and accounting boundaries*, including TTW versus WTW accounting, lifecycle-intensity standards, carbon pricing, and related compliance rules; and (G5) *operational-envelope constraints*, including route or duty-cycle requirements, turnaround time, downtime cost, energy-delivery requirements, and safety handling. The value of the framework lies in connecting transition feasibility to identifiable decision variables and stakeholder responsibilities. Table 5.1 shows how the five gates are supported by the empirical evidence from the appended publications.

Table 5.1: Empirical basis for the adoption-gates framework.

Paper	**Domain**	**Main mechanism**	**Primary gates**
Paper I	RoPax fuel roadmap	Fuel ranking depends on the WtP boundary, methane slip, upstream fuel characteristics, fuel availability, and carbon-cost assumptions.	G1, G3, G4
Paper II	Farm hydrogen	LCOH and NPV depend mainly on electricity price, electrolyser utilisation, hydrogen-system configuration, and seasonal demand.	G1, G2, G3, G5
Paper III	Battery-electric RoPax	BEV performance depends on electricity sourcing, route geometry, port charging infrastructure, and the inclusion of lifecycle and policy-related costs.	G1, G2, G4, G5
Paper IV	NRMM quarry duty	BEV and FCEV performance depends on upstream electricity or hydrogen supply, infrastructure utilisation, productive duty cycle, and site conditions.	G1, G2, G3, G5

A similar governance logic appears in other hard-to-abate transport segments. In heavy-duty road freight, decarbonisation is likewise shaped by the interaction of policy, technical readiness, infrastructure deployment, and life-cycle performance rather than by vehicle technology in isolation (Seemungal et al., 2021). This reinforces the value of adoption gates as a cross-sector heuristic for analysing when transition pathways become implementable in practice.

The shipping context makes the gate logic particularly explicit. IMO sets the overall ambition and transition direction (International Maritime Organization, 2023), while FuelEU Maritime defines WTW intensity obligations that turn upstream emissions into compliance variables (European Commission, 2025; DNV, 2025a). Under these conditions, policy is not peripheral to adoption: it directly affects competitiveness by determining whether methane slip, upstream electricity intensity, and fuel-chain emissions become cost-relevant. The stakeholder implication

is that shipowners cannot decarbonise independently of ports, fuel suppliers, and electricity procurement arrangements.

In off-road applications, the same gate structure applies, but the relative importance of the gates differs. Current EU NRMM policy remains centred on pollutant emissions and type approval rather than direct CO_2 regulation (European Union, 2016; European Commission, 2024). As a result, adoption is currently driven more strongly by infrastructure availability, utilisation, and project economics than by immediate exposure to GHG compliance. Site owners, contractors, and OEMs therefore become central actors, while financing and asset-use intensity often determine whether a pathway is viable in practice.

Hydrogen introduces a particularly strong interaction between upstream electricity conditions and supply-chain maturity. Hydrogen cost and emissions depend heavily on electricity prices and carbon intensity, which are shaped by procurement arrangements and electricity market conditions. TEA evidence shows that electricity price and utilisation dominate LCOH outcomes (Aminaho et al., 2025). In decentralised settings such as farming, this means that hydrogen adoption depends less on device choice alone than on aggregation, offtake coordination, and access to favourable electricity supply.

The gate framework also clarifies why pathways differ in strategic character. Some are compatibility-first, such as fuel switching in shipping; others are infrastructure-first, such as battery-electric systems; and others are supply-chain-first, such as hydrogen and electrofuels. These are not merely labels, but shorthand for the condition that most strongly constrains adoption. Because these constraints are both boundary- and unit-sensitive, the dissertation avoids mixed functional units and instead synthesises results qualitatively and conditionally across the appended papers.

Cross-reference. These adoption gates align with the cross-sector mechanisms consolidated in Chapter 2 (Table 2.2), where upstream integrity, enabling infrastructure and utilisation, policy boundaries, and operational envelopes emerge as shared determinants across domains.

5.2 Co-evolution of adoption conditions

Although the adoption gates can be stated analytically, they do not mature simultaneously in practice. Regulatory tightening, market demand, technology readiness, infrastructure deployment, and stakeholder capability often evolve at different speeds. Firms therefore make pathway decisions under conditions of partial alignment rather than full certainty. In this sense, hard-to-abate transitions are shaped not only by whether a pathway performs well, but by whether the surrounding conditions required for implementation emerge in time.

This asynchronous development is visible across all three empirical domains of the dissertation. In short-sea shipping, regulation, fuel availability, port-side infrastructure, and customer willingness to absorb low-carbon transport premiums do not progress in parallel. Evidence from sustainable shipping studies suggests that the additional cost of decarbonised transport may

remain moderate for many higher-value goods, which indicates that market uptake can support transition in some segments. However, this support is uneven across product categories, and lower-value bulk flows remain more exposed to direct cost pressure and regulatory obligation than to voluntary demand pull (Schwartz, Solakivi, et al., 2022). Shipping abatement studies further show that some operational and technological measures can be economically favourable, but that the actors who benefit are not always the same as those who bear the investment burden (Schwartz, Gustafsson, et al., 2020). This makes contractual coordination and cost allocation central to adoption.

In off-road and agricultural systems, the same co-evolutionary logic appears through the interaction of machinery, energy supply, and site conditions. Electrification depends not only on drivetrain capability, but also on rural charging conditions, renewable integration, storage design, seasonal load patterns, and the economic acceptability of high-capital-cost machinery. The agricultural electrification literature shows that machinery electrification and energy-system design must often be developed together because variable renewable output and seasonal demand create balancing problems at farm or site level. At the same time, the high battery share in electric tractor cost affects willingness to adopt, meaning that market readiness and technical readiness remain coupled (Stakens et al., 2023). This is directly relevant to the dissertation's treatment of farm-adjacent hydrogen and distributed low-carbon fuels, where utilisation and aggregation become decisive precisely because energy supply and machinery demand do not align smoothly over time.

In maritime fuel and propulsion transitions, asynchronous development appears through the joint dependence of pathway choice on vessel technology, fuel production, and infrastructure build-out. Comparative techno-economic studies show that the relative attractiveness of batteries, fuel cells, methanol, ammonia, and other alternatives depends on ship type, propulsion efficiency, storage requirements, annual utilisation, and infrastructure cost rather than on fuel price alone (Korberg et al., 2021). Lifecycle work similarly shows that fuel chain, vessel class, and operational profile must be assessed together (Seithe et al., 2020). The implication is that pathways do not become viable when a single technology improves, but when multiple technical, logistical, and commercial conditions mature together.

Taken together, these patterns show that pathway adoption in hard-to-abate sectors is best understood as a structured but uncertain process in which policy, infrastructure, market demand, and technology evolve unevenly. Some developments act as accelerators, such as stronger regulation or higher willingness to pay for low-carbon services. Others act as bottlenecks, such as delayed infrastructure build-out, weak utilisation, uncertain fuel availability, or limited customer acceptance. The value of the co-evolution perspective is therefore that it explains why promising pathways may stall, why firms often hedge across multiple options, and why technology performance alone does not determine transition success.

Figure 5.1 presents an original synthesis of this transition logic. It organises hard-to-abate pathway adoption as a structured relationship between transition pressures, adoption conditions,

and resulting outcomes. Within this framework, stakeholder coordination acts as a cross-cutting mechanism through which infrastructure, procurement, compliance, and deployment decisions are aligned. The 2020–2040 axis is illustrative rather than predictive, and the uncertainty layer indicates that policy timing and infrastructure deployment may evolve asynchronously, thereby shifting when the adoption conditions required for lifecycle credibility, costability, cost competitiveness, and scalability are reached.

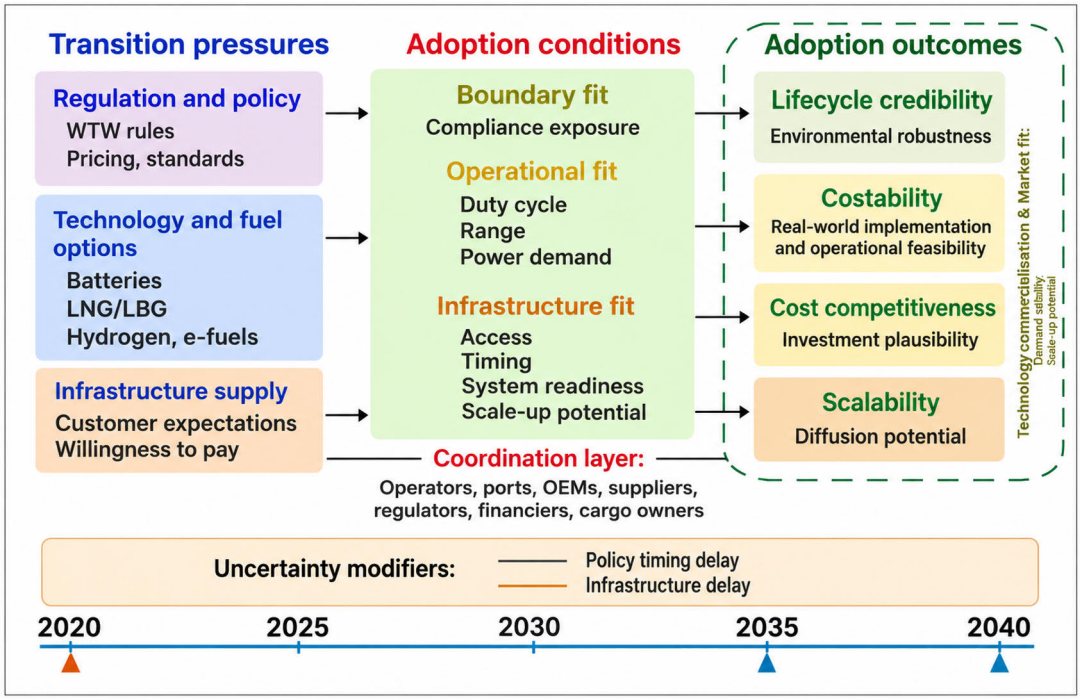


Figure 5.1: Co-evolution of adoption conditions in hard-to-abate transition pathways.

5.3 Short-sea adoption

Short-sea shipping adoption decisions are distributed across shipowners and operators, ports, grid operators, fuel suppliers, regulators, and customers. Unlike bulk deep-sea shipping, many short-sea services are exposed more directly to passenger demand or customer-facing freight markets, which means that costs cannot always be transferred automatically without affecting competitiveness. Adoption analysis must therefore extend beyond technology cost and include who bears transition costs, how infrastructure is coordinated, and whether markets are willing to absorb at least part of the additional cost of lower-carbon transport.

This demand-side dimension is increasingly important in the literature. Evidence from Finnish maritime trade suggests that the price premiums required to cover shipping with alternative and typically more expensive fuels may remain moderate for many higher-value

product groups, implying that sustainable shipping can in some cases be positioned not only as a compliance obligation but also as a differentiated market offering (Schwartz, Solakivi, et al., 2022). At the same time, that same logic does not apply evenly across cargo types: lower-value bulk goods remain more exposed to cost sensitivity, which means that voluntary market pull is likely to be selective rather than universal. In practice, this reinforces the need to analyse short-sea adoption as a market-segmented process rather than as a single homogeneous transition.

Roadmap fuels such as MGO/LNG/LBG mixtures, biofuels, and other drop-in or near-drop-in options typically represent a compatibility-first pathway. Their attraction lies in the possibility of reducing emissions without immediately redesigning vessels or requiring extensive port-side electrical upgrades. However, under lifecycle-based policy regimes, their competitiveness depends increasingly on upstream fuel integrity and methane management. The ICCT analysis of LNG shows that methane slip can eliminate or reverse lifecycle climate advantages relative to conventional marine fuels (Pavlenko et al., 2020), while real-engine evidence demonstrates that methane slip is strongly load-dependent in ways that are directly relevant to short-sea operating profiles (Kuittinen et al., 2024). Under FuelEU's WTW framework, such upstream and non-CO_2 effects become compliance-relevant rather than merely sensitivity parameters (European Commission, 2025; DNV, 2025a). For adoption, this means that roadmap fuels are exposed not only to fuel price and supply availability, but also to the credibility of their lifecycle performance under tightening regulation.

At the same time, the economics of short-sea decarbonisation are not uniformly negative. Shipping abatement studies indicate that combinations of operational and technological measures can improve environmental performance while remaining economically attractive, and in some cases can yield positive net present value (Schwartz, Gustafsson, et al., 2020). This distinction matters for adoption. Fuel switching that increases compliance costs and operational complexity is a different decision from efficiency-enhancing investments that reduce fuel use while lowering emissions. In practice, short-sea transition strategies often combine both, but the underlying business logic differs. The former depends more on regulation, fuel markets, and willingness to pay; the latter may be attractive even under weaker policy pressure.

Battery-electric and plug-in pathways represent a more infrastructure-first transition logic. Published benchmarks and suitability studies consistently show that electrification is feasible only where port power upgrades, charging equipment, berth access, and vessel scheduling align (Perčić et al., 2022; Kanchiralla et al., 2025; Siljama et al., 2023). In this pathway, gate ownership shifts relative to liquid-fuel options: ports and grid operators become central because they determine charging enablement, while electricity suppliers and procurement strategies determine upstream integrity. The shipowner's investment decision is therefore necessary but not sufficient. Comparative studies of future fossil-free ships reinforce this point by showing that the relative attractiveness of batteries, fuel cells, and alternative fuels depends on ship type, annual utilisation, storage penalties, and infrastructure cost rather than on propulsion technology alone (Korberg et al., 2021). Lifecycle evidence similarly shows that vessel type,

fuel chain, and operational profile must be considered together (Seithe et al., 2020). Adoption in short-sea shipping is therefore not a matter of one fuel or powertrain outperforming all others, but of selecting pathways that remain workable under specific route, infrastructure, and policy conditions.

A key adoption mechanism in short-sea segments is infrastructure utilisation. Charging assets, bunkering systems, and port upgrades are capital-intensive, and their cost per transported service declines only if they are used sufficiently. This creates incentives for shared infrastructure, standardisation, and coordinated deployment, for example at terminal level across multiple vessels or operators. It also creates a major bottleneck: vessel technology can mature faster than supporting infrastructure, producing a situation in which technically viable low-carbon vessels cannot be deployed at scale because charging or fuel supply remains inadequate. In this sense, adoption depends not only on technology readiness but on the timing and governance of infrastructure investment.

Policy and boundary rules can also invert apparent cost rankings. FuelEU and related policy instruments reward lower-intensity pathways and penalise higher-intensity ones, which means that adoption analysis must be explicit about whether EU ETS exposure, FuelEU obligations, and upstream emissions are included in the economic boundary (DNV, 2025a; European Union, 2023). Otherwise, comparisons risk overstating the attractiveness of pathways that appear competitive under narrower accounting rules but lose position once lifecycle obligations are applied. This is why the thesis treats policy as part of the adoption boundary rather than as an external background condition.

Cross-reference. The short-sea mechanisms discussed here—upstream dependency, port-power constraints, selective market pull, and WTW compliance exposure—correspond to the short-sea column in Table 2.2.

Finally, the appended short-sea papers sit within this broader adoption logic. The roadmap paper makes passenger exposure and carbon-cost trajectories explicit, while the battery-electric benchmark shows how upstream electricity sourcing and policy inclusion alter both WTW outcomes and economic competitiveness. Taken together with the wider literature, they support a conditional adoption statement: short-sea transitions advance where infrastructure, upstream energy integrity, route suitability, and market or regulatory support align, but remain contested where these conditions mature unevenly.

5.4 Off-road adoption

Off-road vehicles do not adopt as a single market. Adoption segments align with the sectors in which machines operate: temporary construction sites, high-utilisation quarries and mines, seasonal agriculture, remote forestry, and fixed ports and logistics yards. Review literature consistently emphasises that the same drivetrain can be attractive in one segment and infeasible in another because utilisation patterns, power demand, operating environment, and infrastructure

conditions differ fundamentally (Antila et al., 2025; Un-Noor et al., 2022; Pesonen et al., 2025). A credible adoption analysis must therefore explain market segmentation rather than implying that one transition route can be generalised across all non-road applications.

A useful comparative lens is the wider heavy-duty transport literature. The decarbonisation of heavy goods vehicles has likewise been framed around the interaction between policy, infrastructure, technical readiness, and lifecycle performance rather than around vehicle technology in isolation (Seemungal et al., 2021). This broader evidence supports the same conclusion reached for NRMM: adoption depends not only on the technical potential of batteries or hydrogen, but on whether route or duty profile, charging or refuelling access, operational flexibility, and policy context are sufficiently aligned to make deployment credible.

In construction, the most binding gates are often infrastructure utilisation and operational continuity. Contractors operate under project schedules in which downtime is costly, while sites are often temporary and may lack sufficient grid access to justify permanent upgrades. Electrification therefore depends not only on machine cost, but also on temporary-site charging solutions, mobile storage, or hybrid arrangements that can support variable loads without undermining productivity. Reviews of off-road electrification identify charging access, battery size and weight, durability, and recharging interruptions as central barriers, which is why hybridisation frequently appears as a transitional strategy where full electrification remains operationally constrained (Un-Noor et al., 2022). In adoption terms, this means that construction firms assess machinery and energy supply together rather than separately.

In quarries and some mines, site ownership and high utilisation can shift the adoption logic substantially. Here, infrastructure can often be shared across fleets, which improves utilisation and lowers unit cost. However, the binding constraint moves to energy-delivery rate: charging and refuelling must fit within tightly structured operational cycles, and infrastructure design becomes integral to productivity. Evidence from mine electrification studies shows that site geometry, haul length, topography, and system design determine the extent to which electrification yields both fuel savings and operational gains (Baranauskas et al., 2025). This is precisely the kind of context in which work-based functional units and infrastructure allocation become analytically credible, and it is therefore a strong empirical basis for the appended quarry-duty analysis in the dissertation.

Agriculture presents a different adoption problem because seasonality creates a structural utilisation gap. Machinery is used intensely during peak periods and remains underutilised for long periods outside them, which makes both battery-electric charging assets and hydrogen production systems difficult to finance if sized only to peak demand. In this segment, aggregation and shared infrastructure may be more important than the machine itself, because co-operatives, shared hubs, and complementary demand can raise utilisation and improve the economics of enabling assets. The agricultural electrification literature strengthens this interpretation by showing that adoption barriers extend well beyond drivetrain capability. Renewable integration, storage design, land-use implications, charging access, and farmer willingness to invest in

high-cost electric machinery all affect feasibility (Stakens et al., 2023). Earlier market-oriented work on electric tractors similarly pointed to limited infrastructure, battery-capacity constraints, and behavioural acceptance as barriers to uptake (Caban et al., 2018). This means that in agriculture, technical readiness and market readiness are closely coupled.

Forestry and other remote operations introduce further constraints because grid access is weak, distances are long, and downtime can be especially expensive. Applied work on forestry NRMM electrification shows that adoption feasibility depends on coordinated charging strategies, mobile energy storage, and off-grid or weak-grid system design (Skogforsk, 2023). By contrast, ports and logistics yards more closely resemble fixed industrial sites with high utilisation, where electrification can be more attractive if grid capacity is available (Antila et al., 2025). Across NRMM segments, the same general lesson holds: adoption is not determined simply by whether batteries or hydrogen work in principle, but by whether the site, energy system, and duty cycle jointly support them.

Policy context influences adoption indirectly but increasingly strongly. Current EU Stage V regulation targets pollutant emissions and type approval rather than explicit CO_2 standards (European Union, 2016), which means that climate-driven adoption still depends more on procurement choices, client requirements, and local zero-emission rules than on a unified carbon-compliance framework. At the same time, literature and policy advocacy increasingly treat NRMM emissions as significant and likely to attract tighter future regulation (Transport and Environment, 2024). This creates an important strategic tension: investments made under current weak climate-policy pressure may become misaligned if future lifecycle or zero-emission requirements strengthen. For this reason, adoption analysis in NRMM should already be boundary-sensitive and should test whether pathways remain credible under stricter future conditions.

Cross-reference. NRMM's feasibility levers—utilisation dominance, site-specific infrastructure constraints, seasonal demand asymmetry, and hybrid enabling assets—align with the NRMM column in Table 2.2.

Taken together, the literature supports a conditional view of off-road adoption. Electrification is strongest where utilisation is high, energy supply can be coordinated, and downtime can be managed. Hybrid and fuel-based pathways remain relevant where power demand is high, operations are remote, or asset-use patterns are too intermittent to support heavy infrastructure investment. The appended off-road paper contributes to this literature by quantifying these trade-offs in a quarry-duty context using work-based environmental and economic metrics.

5.5 Hydrogen and e-fuel adoption

Decentralised hydrogen adoption is a textbook case of utilisation-dominated economics. Techno-economic evidence consistently shows that levelised hydrogen cost is driven primarily by electricity price and capacity factor, with CAPEX and financing acting as additional but

secondary determinants (Aminaho et al., 2025). In farming, this is especially important because machinery fuel demand is seasonal, which constrains capacity factor and spreads fixed investment over too few units of output. Adoption therefore depends less on whether hydrogen is technically usable and more on whether utilisation can be increased beyond farm-only demand and whether electricity can be procured at sufficiently low cost and low carbon intensity.

The same conclusion is visible in the electrofuel literature more broadly. Reviews of electrofuel costs show that hydrogen-derived fuels are shaped less by the identity of the final fuel than by the economics of hydrogen production itself. Electricity price, electrolyser investment, and operating hours recur as dominant cost drivers across PtX pathways, while earlier PtL studies similarly show that full-load operation and conversion efficiency are decisive for the economics of storing renewable electricity in liquid hydrocarbons (Brynolf et al., 2018; König et al., 2015). This matters for adoption because it shifts attention away from end-use fuel labels toward the prior question of whether hydrogen production can be made credible and sufficiently utilised.

Beyond hydrogen, farms may participate in e-fuel pathways more plausibly through farm-adjacent biogenic CO_2 and biomethane value chains than through on-farm synthesis. Biogenic CO_2 from biomethane upgrading is increasingly discussed as a sustainable carbon source for regional e-fuel production, but its practical value depends on transport, purification, aggregation, and long-term offtake. Adoption levers therefore include CO_2 contracting, regional coordination, and stable fuel demand rather than farm-scale autonomy (Cordova et al., 2023; European Biogas Association, 2025; Transport and Environment, 2025). This reinforces the broader dissertation argument that distributed energy transitions are constrained by coordination and system boundaries rather than by technology labels alone.

The critical adoption gate is therefore often not technology readiness but business-model structure. Standalone farm systems sized to seasonal peaks risk low utilisation and high LCOH, whereas shared hubs, co-operative systems, regional offtake, or integration with other hydrogen demand can improve infrastructure use and reduce unit cost. This is consistent with hydrogen adoption in other sectors, where refuelling hubs or industrial clusters depend on demand aggregation to justify infrastructure and supply-chain investment.

Electricity procurement is the second binding gate. Even where utilisation is improved, high electricity prices can dominate hydrogen cost. TEA literature shows that electricity often contributes a majority share of LCOH under realistic conditions (Aminaho et al., 2025). Adoption therefore depends not only on physical access to power, but on tariff structure, procurement contracts, local renewable supply, or operating strategies that exploit lower-price periods without collapsing utilisation. In this way, procurement design becomes part of the adoption model rather than a mere background assumption.

Upstream integrity is equally important for environmental credibility. Hydrogen produced with carbon-intensive electricity may perform poorly under WTW accounting and fail future lifecycle-based policy requirements. This ties decentralised hydrogen back to the wider dissertation logic in shipping and off-road systems: hydrogen is not inherently low-carbon,

but conditionally so depending on the upstream electricity system and accounting boundary. Adoption in regulated or certification-sensitive markets therefore requires credible carbon accounting and proof of upstream integrity.

Safety and logistics form additional adoption constraints. Hydrogen storage and handling introduce permitting, operational, and safety requirements that may be manageable at industrial scale but are more demanding in decentralised settings (Eißler et al., 2023). Likewise, proposed by-product revenues from oxygen or heat should not be treated as automatic economic benefits unless a realistic market, transport chain, or onsite use can be demonstrated. In adoption terms, these revenues are conditional opportunities rather than baseline assumptions.
Cross-reference. Within Table 2.2, farm-adjacent fuels are characterised by strong sensitivity to electricity availability, unit utilisation, upstream integrity, and certification value—the same conditions that shape decentralised hydrogen and e-fuel adoption.

Finally, the appended farm hydrogen paper provides quantitative evidence for these mechanisms by reporting NPV and LCOH under baseline and improved utilisation scenarios across regions. Read alongside the wider literature, its contribution is to show that decentralised hydrogen becomes plausible only under combinations of high utilisation, coordinated demand, and low-cost, low-carbon electricity procurement. Aggregation is therefore not a peripheral optimisation, but a central adoption condition.

The adoption-gates framework contributes to the transition-pathway literature by connecting three analytical traditions that are often treated separately. From LCA, it adopts boundary discipline and upstream emissions accounting. From TEA, it adopts utilisation, capital recovery, and cost-exposure logic. From socio-technical transition analysis, it adopts the insight that technologies diffuse only when infrastructures, institutions, markets, and actor capabilities co-evolve. The contribution of this dissertation is to operationalise these insights for hard-to-abate transport and machinery pathways through a compact framework that can be applied across sectors without forcing artificial numerical comparability. The framework therefore provides a bridge between quantitative pathway assessment and practical adoption analysis.

Chapter 5 summary

Key takeaways: The cross-sector synthesis shows that practical adoption depends on the alignment of upstream energy integrity, infrastructure and utilisation, supply-chain maturity, policy and accounting boundaries, and operational constraints. These conditions do not necessarily mature at the same pace, making transition pathways both context-dependent and temporally uncertain. The adoption-gates framework therefore shifts the decision question from identifying a universally superior technology to determining whether the conditions required for a pathway to become credible and deployable are sufficiently aligned.

Chapter 6

Conclusions

This dissertation examined how decarbonisation pathways in selected hard-to-abate sectors should be assessed when lifecycle boundaries, upstream energy conditions, infrastructure constraints, utilisation, and policy rules are made explicit. The conclusions are organised around the three research questions and the integrative contribution of the adoption-gates framework. Across the studies, the central finding is that pathway performance is not an intrinsic property of a fuel or technology, but depends on how the pathway is configured, supplied, operated, and evaluated. Decarbonisation is therefore treated as a pathway-assessment problem rather than as a simple technology-substitution problem.

In relation to the first research question, the dissertation shows that lifecycle boundaries, functional units, and assessment assumptions can materially alter pathway rankings. In short-sea shipping, LNG, LBG, methanol, and battery-electric pathways cannot be credibly compared on tank-to-wake emissions alone because methane slip, upstream fuel production, and electricity sourcing can alter the relative results. In off-road machinery, work-based comparison is necessary because machine productivity and duty cycle affect both emissions and costs. In decentralised hydrogen production, electricity price and utilisation determine whether the pathway is economically plausible. The answer to RQ1 is therefore that boundary integrity and service-based functional units are prerequisites for credible comparison.

Regarding the second research question, the results show that economic and environmental viability is shaped by the operating context. Electrification is strongest where routes or duty cycles are predictable, infrastructure can be intensively used, and electricity is low-carbon. This is evident in both the battery-electric RoPax case and the quarry-duty NRMM case. By contrast, LNG-based pathways remain vulnerable to methane-related effects, and hydrogen-based pathways remain highly sensitive to electricity price, capacity factor, and upstream production route. The answer to RQ2 is therefore that no pathway is universally preferable; each becomes credible only under specific technical, operational, and market conditions. In relation to the third research question, the dissertation shows that deployment depends on the alignment of enabling systems. Short-sea electrification requires port power, charging windows, route regularity, and credible electricity procurement. Off-road electrification requires site-level energy infrastructure,

sufficient machine utilisation, and compatible duty cycles.

Decentralised hydrogen requires aggregated demand, favourable electricity procurement, and sufficient utilisation of infrastructure. The thesis contribution is the adoption-gates framework, which operationalises five conditions for pathway credibility and connects LCA and TEA results to real-world deployment. This framework shows that credible decarbonisation requires alignment between technologies, upstream energy systems, infrastructure, utilisation, and regulation. For researchers, pathway assessment must remain boundary-explicit and service-based; for practitioners and policymakers, pathway adoption must be evaluated based on enabling conditions, not on technology labels alone.

Chapter 7

Recommendations and Future Research

Building on the adoption-gates synthesis and the conclusions above, the practical implication is that decarbonisation strategies in hard-to-abate sectors should be designed as pathway-enablement strategies. This means that technology selection should be coordinated with lifecycle accounting, infrastructure planning, utilisation models, and policy incentives from the beginning.

Three practical recommendations follow. First, decision-making frameworks should remain lifecycle-based, especially in sectors where methane slip, electricity sourcing, hydrogen production route, or carbon sourcing materially affect performance. Second, infrastructure planning should be integrated with technology choice from the outset, because port charging, site electrification, hydrogen supply, and shared-use systems determine whether low-carbon pathways are economically workable in practice. Third, business models and policy incentives should focus more directly on utilisation, since low capacity factor repeatedly emerged as a structural barrier in both decentralised hydrogen and infrastructure-intensive equipment transitions.

The dissertation also points to several priorities for future research. These can be summarised as follows:

- Dynamic modelling of infrastructure and fleet co-evolution, especially in shipping and off-road systems where investment timing and utilisation strongly affect pathway viability.
- Expanded uncertainty analysis that captures correlated risks in electricity prices, hydrogen prices, carbon prices, and policy trajectories.
- Stronger integration of pathway models with regional energy-system models in order to assess competition for renewable electricity, grid constraints, and sector coupling effects.
- Multi-actor adoption modelling that examines how risks, costs, and responsibilities are distributed among operators, infrastructure providers, OEMs, regulators, and energy suppliers.
- Broader environmental assessment beyond climate indicators, particularly for off-road and hydrogen systems, where upstream resource use and burden shifting may become

increasingly important.

Overall, the key implication is that credible transition in hard-to-abate sectors will depend less on identifying a universal technological winner and more on aligning energy supply, infrastructure, utilisation, and policy design. Future work that deepens these linkages will be essential for supporting robust and scalable decarbonisation pathways.

Declaration of AI Use

Generative AI tools were used in a limited and supportive role for language editing, readability improvement, structural revision, and formatting assistance in the kappa. All AI-assisted output was critically reviewed, verified, and substantially edited by the author. The author takes full responsibility for the final text, scientific content, analysis, interpretation, citations, and conclusions of the dissertation. AI tools were not used to generate original research results or to replace scholarly judgement.

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Appended papers

Mayanti, B., Hellström, M., and Katumwesigye, A. (2025). Assessing the decarbonization roadmap of a RoPax ferry. Maritime Economics & Logistics, 27, 123–146.

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ORIGINAL ARTICLE

Assessing the decarbonization roadmap of a RoPax ferry

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Abstract

The reduction of emissions from shipping is necessary to combat climate change. One viable option is to change the fuels utilized. In this study, we investigate the environmental and economic performance of marine diesel oil (MDO), liquified natural gas (LNG), liquified biogas (LBG), and a mixture of LNG and LBG. We study a real case of a roll-on/roll-off passenger ship (RoPax) in Finland. Life cycle thinking is applied to assess the environmental impact, covering emissions from well to propeller (raw material extraction, fuel production, transportation, storage, and combustion), while the economic implications are estimated through future fuel prices and carbon pricing from 2023 to 2050. The carbon pricing covers different carbon tax schemes, namely stated policies scenario (STEPS), sustainable development scenarios (SDS), and net-zero emissions (NZE). STEPS reflects the existing measures and policies under development; SDS pursues to meet the goal of Paris Agreement, while NZE aims to reach net zero. Adopting LNG would improve carbon dioxide emissions, but the overall climate change impact was not significantly lower than MDO. It is also found that the biggest environmental improvement can be obtained by switching to LBG, although future availability can be an issue. The economic assessment shows that LBG has the highest fuel price uncertainties, although its carbon cost will be the lowest. Alternatively, using LNG & LBG mixture can serve as a transition path to contain climate change while dealing with its price uncertainty and availability.

Keywords Decarbonization · Short-sea shipping · Liquefied natural gas · Liquefied biogas · Marine diesel fuel · LCA

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1 Introduction

Shipping is a considerable contributor to greenhouse gas (GHG) emissions, responsible for 1076 million tonnes in 2018 or some 3% of global GHG emissions (IMO 2021). Recent international consensus outlines a path towards net-zero GHG emissions shipping around 2050. Yet, the sector's emissions are expected to grow as the demand for shipping increases with world trade (Traut et al. 2018). This puts both the sector and the individual shipowners and operators in a difficult situation. While most emissions originate from large ocean-going cargo vessels (Aakko-Saksa et al. 2023), emissions from short-sea shipping are important at local level and for the sector to move towards zero emissions.[1] Short-sea shipping is also interesting because it involves passenger travel, notably on the so-called *roll-on roll-off* passenger vessels (RoPax). According to the fourth IMO GHG study (IMO 2021), Ferry-RoPax vessels were responsible for some 37 million tonnes of CO_2 emissions in 2018 (out of 1056 million tonnes for all shipping). These ships typically show higher consumption figures per transportation work due to different speed profiles and the compromises made while serving both the needs of cargo and passengers. Yet, short-sea and RoPax shipping have received less attention in the scientific literature on maritime GHG emissions reduction, with just a few notable exceptions (Zis et al. 2020).

Decarbonization often comes with a considerable investment cost for shipowners. Some investments can indeed be profitable (Schwartz et al. 2020), but especially when we move to complete carbon neutrality and new power sources the increased costs are more difficult to cover with current freight prices (e.g. liquified biogas was in 2023 30–87% more expensive than MDO/MGO, see Table 3). While such investments indeed serve to differentiate the services provided by a shipping company, the transition towards carbon-neutral shipping cannot rely only on voluntary initiatives. Owing to economic and technological barriers, incentives at various regulatory levels are needed (Christodoulou and Cullinane 2021). Moreover, several studies have pointed out that the price premium for zero-emissions shipping is very small (Schwartz et al. 2022; World Economic Forum 2021). Regarding passenger traffic, the issue is less clear-cut as the value chain is shorter, and the price increase more hits the passenger directly. Hence, the issue boils down to customers' willingness to pay, which in practice is still lacking. Another issue concerns appropriately dividing the emissions burden between passengers and cargo, something of particular relevance, of course, for RoPax vessels (for a general overview, see Fridell et al. 2018). Moreover, RoPax like RoRo (roll-on, roll-off) vessels are prone to the double load factor problem, that is, the failure to effectively utilize the capacity of both the vessel and the trucks onboard the vessel, which leads to high emissions per transportation work (Hjelle 2011). Adding to that, RoPax vessels are typically also subject to substantial daily, weekly, and seasonal fluctuations in capacity utilization.

[1] While there appears to be no exact definition of short-sea shipping, the term is often used in contrast to intercontinental, deep sea shipping and refers to transport over relatively short sea distances, such as routes between two ports within the EU.



The situation is challenging for shipowners and operators as regulations are evolving. There is also considerable uncertainty on the price of alternative fuels that hold the biggest GHG emissions reduction potential. Liquefied biogas (LBG), however, offers technically an easy way out, for ship owners with LNG fleets. Hence, this article assesses a decarbonization roadmap that builds on a gradual shift from MDO/LNG to LBG and its cost implications for a RoPax ferry. The contribution is a thorough analysis of a real-case ferry, exploring different input parameters. The analysis includes the environmental and economic aspects of using different types of fuels and carbon pricing. Any trade-off occurring among different fuel scenarios or carbon pricing schemes will provide valuable information for both ship owners and regulators.

The article is organized as follows. We first provide an overview of current regulations and available GHG emissions abatement measures in the maritime industry. Next, we present our method and the case company we have investigated. We then present and discuss the GHG footprint analysis results and the cost implications of the various abatement measures proposed by the case company. We conclude with some implications for the industry and some ideas for further research.

2 Literature overview

2.1 The need for decarbonization of shipping

A significant part of the literature highlights the International Maritime Organization's (IMO) strategic initiatives to curtail GHG emissions from shipping (Chen et al. 2019; Xing et al. 2020; Schwartz et al. 2022). IMO has recently revised its greenhouse gas (GHG) strategy, now aiming to establish a target of achieving net-zero emissions from international shipping by 2050 (Comer and Carvalho 2023). This target indicates a significant shift in the sector's approach to environmental stewardship (IMO 2021). This reflects a notable shift from IMO's previous goal of a 50% reduction, emphasizing a transition towards alternative, low-emission fuels by 2030, relative to 2008 levels. The strategy introduces regulatory measures like the Carbon Intensity Indicator (CII): a regulatory tool to enforce reductions in CO_2 and the implementation of the Energy Efficiency Existing Ship Index (EEXI). The purpose is to enforce emissions reductions, with plans for these tools to be updated by 2026 for enhanced effectiveness (Chen et al. 2019; Comer and Carvalho 2023; Pape 2020).

The European Union's regulatory interventions are also a focal point in the literature, illustrating a proactive approach to integrating maritime emissions into broader GHG reduction targets. The MRV regulation (No. 2015/757), effective from 2017, establishes a comprehensive framework for monitoring, reporting, and verifying CO_2 emissions from ships exceeding 5000 GT and operating in EU and EEA ports (European Council 2023). Building on this, the 'Fit for 55' package aims for a 55% cut in emissions from shipping by 2030, introducing measures such as the inclusion of shipping in the EU Emissions Trading System (ETS) and the Fuel EU Maritime initiative to promote the uptake of low-GHG fuels (DNV 2023).



According to Xing et al. (2020), to enhance maritime energy efficiency and mitigate CO_2 output, MARPOL Annex VI mandates the implementation of the Energy Efficiency Design Index (EEDI) for newly built ships and the Ship Energy Efficiency Management Plan (SEEMP) applicable to all vessels. Furthermore, aligning with global efforts against climate change, the Initial IMO Strategy for Reducing GHG Emissions from Ships was established in April 2018. Therefore, the question about why transitioning is important has long been answered by these voluntary commitments, mandates, and regulations, being introduced systematically at all stakeholder levels, transforming to new shift in industrial competitive edge for different players in the industry.

Another initiative, the revision of the Energy Taxation Directive (ETD), implies a removal of the current tax exemptions on marine fuels sold within and for use within the European Economic Area (EEA) European Commission (2022). The existing mandatory tax exemption for marine fuels is abolished while, at the same time, new tax exemptions are introduced to stimulate the use of fuels with lower GHG emission factors (EF). While the former initiative would motivate the use of alternative fuels, the latter would make them more competitive than fossil fuels. Europe is furthermore determined to reduce transportation emissions to 60% of 1990 levels by 2050 due to concerning statistics on greenhouse gas emissions (Bicer and Dincer 2018). This ambitious goal requires a collective approach that involves exploring alternative fuels, promoting technological development, enforcing strict regulations, and adopting sustainable methods.

2.2 Decarbonization measures in shipping

There are many strategies currently underpinning the maritime industry's quest to reduce or eliminate its GHG emissions. Measures can be divided into five categories (Xing et al. 2020).

1. Technical measures which include ship resistance reduction, propulsion efficiency improvement, and marine power plant development (e.g. waste heat recovery).
2. Operational measures including slow steaming, cold ironing (shore power), voyage optimization, human factors (awareness of energy consumption and savings), and optimized maintenance.
3. Eco-friendly or alternative fuels that can be grouped into LNG, biofuels, and electrofuels (i.e. fuels produced by using renewable electricity) and conventional fossil fuels with carbon capture and storage.
4. Alternative power sources such as wind, solar, nuclear energy, or battery-electric systems are examples.
5. Onboard carbon capture and storage (CCS).

Although these methods show significant potential in reducing GHG emissions, their implementation can result in additional costs due to increased requirements for installation, operation, and maintenance (Deniz and Zincir 2016; Seithe et al. 2020).



As a result, the most implemented measures have so far tended to be those with small energy efficiency gains and low additional costs (Rehmatulla et al. 2017).

In the long run, alternative fuels possess the biggest GHG abatement potential (Ampah et al. 2021). Various fuels, such as methanol, biodiesel, ammonia, biogas, hydrogen, and LPG, are being investigated (Deniz and Zincir 2016). Generally, both LNG and LPG are predominantly considered transitional fuels, and it is argued that biofuels lack the required scalability to become a dominant fuel in shipping (Englert et al. 2021a, b). A study conducted by Perčić et al. (2020) points out that as of March 2018, roughly 248 ships were using LNG in their operations, particularly in passenger ferries across Nordic coastal regions. This can be attributed to the adoption of dual-fuel engine technology in the shipping sector. Furthermore, a press briefing from Wärtsilä indicated that there were about 100 LNG-fuelled ships in operation, 72 ships in discussions for retrofitting to LNG, and 101 LNG-fuelled ships newly ordered in Germany and Norway (Wärtsilä 2017). However, it is important to note that while reducing CO_2 emissions, unburnt methane emissions (methane slip) pose environmental concerns (Grönholm et al. 2021). Recent measurements showed methane slip from newly built engines can achieve values as low as 1.4 g/kWh (Kuittinen et al. 2023). Overall, each alternative fuel has its unique characteristics and obstacles to overcome like the methane slip for LNG. The common challenge is their price compared to fossil ones, although price differences are expected to decline gradually (Brynolf et al. 2018).

The electrification of propulsion systems should be separately mentioned as a technical measure to improve energy propulsion efficiency, and as an alternative power source in the form of battery energy storage systems (BESS). The shift from mechanical to electric propulsion is made feasible through advancements in various energy sources. Decarbonization and electrification have fostered a mutual relationship, culminating in the creation of fully integrated electric power systems. Electrification, especially with the surge in renewable energy and innovations in battery technologies, is crucial for sustainable short-distance travel (Inal et al. 2022). For example, popular pure battery-electric ships such as ‘Ampere’ and ‘BB Green’ are RoPax ferries. The former uses a 1-MWh lithium battery module and can transport 120 cars and 360 passengers with a maximum speed of 10 knots. According to Fan et al. (2021), the boat in question has a 200-kWh lithium battery module and can reach up to 30 knots for 30 min. In China, a 2000 t bulk carrier called ‘Blowfish’ uses lithium batteries and supercapacitors as its power sources, with a battery capacity of about 2400 kWh and an endurance of 80 km (Fan et al. 2021). According to a study by Korberg et al. (2021), battery-electric propulsion in large ferries is more economically meaningful than all fuel options except for biofuels, like e-biomethanol and BioDME, in internal combustion engines (ICE).

3 Materials and methods

The environmental and economic implications of different marine fuels were investigated in an actual case study of Aurora Botnia, a Finnish roll-on/roll-off passenger (RoPax) ferry on the Vaasa (Finland)–Umeå (Sweden) route (Fig. 1). The energy



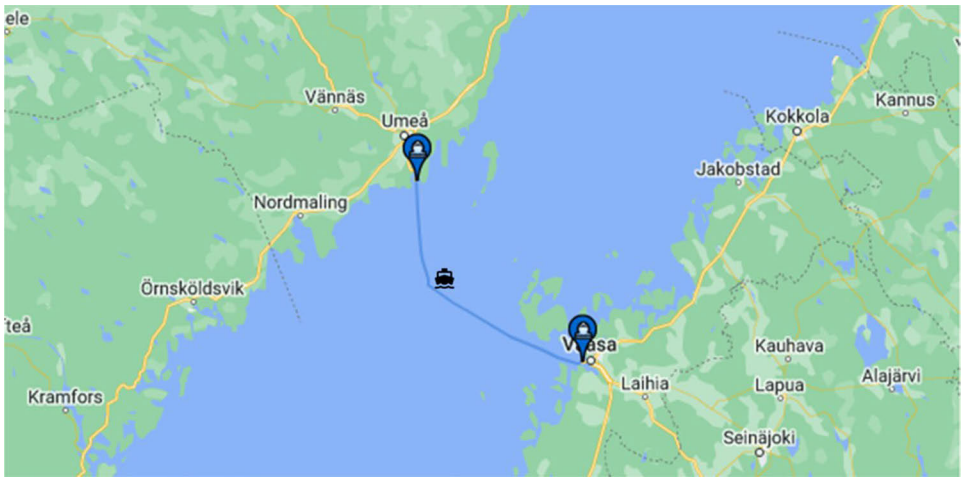

Fig. 1 Aurora Botnia sea route

carriers are marine diesel oil (MDO), liquefied natural gas (LNG), and liquefied biogas (LBG). Aurora Botnia is the only ferry that covers Vaasa-Umeå route with a total of 20–22 sailings each week. On each voyage, the ferry cruises at an average speed of 14 knots with a crossing distance of 53 nm. Its gross weight and deadweight are 24,300 tonnes and 3500 tonnes, with a 1500-m lane and 935 passenger capacity. It has dual-fuel engines that can burn MDO/MGO, LNG, and/or LBG.

3.1 Life cycle thinking

The study applies the *life cycle thinking* (LCT) concept in assessing the environmental impacts. LCT is a holistic and structured approach to incorporating sustainability considerations into decision-making (Sala et al. 2019). This approach goes beyond the conventional method of evaluating environmental impacts solely at the production site, by extending the assessment to encompass the entire life cycle of a product, service, or organization, from raw material extraction to final disposal (Life Cycle Initiatives 2023). In the shipping industry context, the assessment covers the emissions generated during fuel production (well-to-tank or WtT) and fuel burning in the use stage (tank-to-propeller or TtP). The coverage of WtT and TtP is also known as well-to-propeller (WtP). By applying life cycle assessment (LCA), a standardized tool to quantify environmental impact built on the LCT perspective, those emissions can be categorized and classified into different environmental impacts (Sala et al. 2021).

This study applies the LCA principle, where upstream emissions are considered, while following the EU MRV requirements. It provides a hands-on example of calculating emissions and presenting the results, offering added value compared to available studies focusing only on the environmental impacts. The study evaluates the fuel consumption per distance and transport work and CO_2 emissions per distance and transport work. In anticipation of the new reporting requirements of the EU ETS, methane (CH_4) and nitrous oxide (N_2O), emissions will be investigated



since these gasses play a major role in climate change. The cost implications were also assessed to improve decision-making.

3.2 Goal and scope

The carbon emissions from using marine diesel oil (MDO), liquified natural gas (LNG), and liquified biogas (LBG) are evaluated through four different scenarios: (i) the use of MDO, (ii) the use of LNG with 5% MDO as pilot fuel, (iii) the use of LNG and LBG mixture with 5% MDO as pilot fuel, and (iv) the use of LBG with 5% MDO as pilot fuel. In the third scenario, the LBG was introduced stepwise in the mixture. At the beginning of year studied, 2023, it was only 0.6%, reaching 95.5% in 2050. Emissions are investigated from 2023 to 2050. The shipping operator strives to improve their environmental performance by improving efficiency (e.g. optimizing the use of batteries and new engines) and transitioning to more sustainable fuel. Hence, fuel consumption is expected to be reduced, and the use of more sustainable fuel is expected to increase annually. The study was conducted following the MRV legislation where carbon calculation is from CO_2 emissions and the mass allocation method is applied (Fridell et al. 2018). The emissions in the study cover raw material extraction, fuel production, transportation, storage, and combustion (well-to-propeller).

The functional unit (FU) for the CO_2 emissions is per transport work. FU is a reference unit for the impacts or emissions quantified that can provide more context in a study and allow comparison with other equivalent studies (Baumann and Tillman 2004). The selected functional unit is made following the EU MRV legislation, where *transport work* indicates the load carried for each nautical mile (nm) distance, distinguished between passengers (pass-nm) and cargo (ton-nm). Differentiating the FU between passengers and cargo can ensure a fair burden distribution by partitioning the system's load input.

3.3 Life cycle inventory

The data on the EF were collected from previous studies. MDO is commonly described as marine fuels composed of several blends of distillates produced by heating and evaporating residual oil (Shafran 2022). It is similar to marine gas oil (MGO) with a slight difference where MDO contains a small fraction of heavy fuel or black refinery feedstock (Oiltanking 2021; Shafran 2022). MDO/MGO does not show a significant difference in CO_2 emissions compared to heavy fuel oil (Spoof-Tuomi and Niemi 2020). The emissions data of MDO from WtT were adopted from Kollamthodi et al. (2016), whereas the TtP emissions was taken from IMO (2021) and Brynolf et al. (2014a, b).

We use data on gas extraction in the North Sea and LNG production in Norway. The gas is assumed to be transported cryogenically to Finland before distribution. The WtT emissions was adopted from (Spoof-Tuomi and Niemi 2020), who have adjusted the LNG production and distribution to suit the Finnish context. The EF



Table 1 Summary of EF from different fuels

Emissions	WtT (g/kg fuel)			TtP (g/kg fuel)		
	MDO	LNG	LBG	MDO	LNG	LBG
CO_2 (fossil)	627.8	504	478.2	3225	2707	49.3
CO_2 (biogenic)	–	–	–	–	–	2564
CH_4	0.90	8.6	16.8	0.06	19.7	20.2
N_2O	0.007	0.008	0.016	0.16	0.11	0.11

factor for the LNG combustion (TtP) was obtained from Prussi et al. (2020) and Kuittinen et al. (2023).

Bio-LNG, commonly called LBG, can be produced from different organic sources such as manure, biowaste, agriculture residue, and landfill gas. This study assumes LBG is produced from municipal organic waste treated in anaerobic digestion. The WtT emissions of LBG was adopted from Kollamthodi et al. (2016). For TtP emissions, the data were mainly taken from Brynolf et al. (2014a, b) and Spoof-Tuomi and Niemi (2020). The LBG produced from organic waste generates fuel that contains biogenic carbon, hence the low fossil carbon emissions during the combustion stage. The summary of carbon emissions of three different fuels is presented in Table 1.

Data regarding the number of passengers, cargo load, fuel consumption, annual number of trips, and distances are necessary to calculate carbon emissions based on the functional unit. This information was obtained from the shipping operator for the year

Table 2 Summary of voyages in the year 2022

Item	Value	Unit
Year	2022	n.a
Fuel consumption	4928 (65,711)	Tonne (MWh)
Trips	1132	Number
Total distance	88,296	nm
Average speed	14.1	Knot
Passengers	267,757	Pax
Cars	55,661	Number
Busses	413	Number
Trailers	22,200	Number
Time at sea	6262	Hours
Fuel cost	5,970,000	€
Revenue	29,293,000	€
Operating profit	3,294,000	€
Bus ticket*	170	€
Car package**	175	€
Adult ticket	43	€
Children ticket	19	€

*Price for the bus only

**Price for the car with passengers of 4 (max 3 children)



2022, combined with publicly available data (Shippax 2023; Wasaline 2022), as shown in Table 2.

The passengers and cargo load from 2023 until 2050 were assumed to increase steadily annually, until they reached 50% ferry capacity in 2040. After this, passengers and cargo loads are assumed to remain unchanged until 2050. At the moment, passenger occupancy is around 36% while cars, buses, and cargo is about 30%. Since the study applies mass allocation, the total mass of passengers and cargo should be calculated. Assumptions of the weight of passengers and their luggage, cars, buses, and trailers were taken from European standards for calculating and reporting GHG emissions from transportation (Finnish Standards Association 2013). The shipping operator provided the data on fuel consumption projections from 2023 until 2050 based on their transition plan. The latter was also used to calculate the LNG and LBG mixture in scenario 4. There, LBG is introduced in 2023 and incorporated gradually until it makes up 95% of the fuel composition in 2050. The complete information concerning the transition plan and the trajectory of the ferry load can be found in Supplementary material Tables 1 and 2.

3.4 Emissions calculation

Total annual fuel consumption information had to be collected to calculate the parameters required by the MRV. The overall emissions can be estimated using fuel consumption and EF, as shown in Eq. (1).

$$EM_i = \sum EF_i^f . Q_f, \tag{1}$$

where EM_i shows the overall emissions i, EF_i^f represents EF factor of emissions i generated by fuel f, and Q_f indicates the quantity of fuel f. Reporting emissions for a RoPax vessel involves an additional step whereby the total burden of emissions is properly allocated between passengers and freight. The allocation can be done using mass or area methods, which generate different results (Fridell et al. 2018). This study applied mass allocation, which has been widely used whenever reliable data are available. The mass calculation should be based on the number of passengers, their accompanied cars/caravans/busses, and total mass cargo (e.g. trailers) (Finnish Standards Association 2013). The expression for mass allocation can be found in Eqs. (2) and (3).

$$Al_p = \frac{Pax.m_p + C.m_c + B.m_b}{Pax.m_p + C.m_c + B.m_b + T.m_t} \tag{2}$$

$$Al_c = \frac{T.m_t}{Pax.m_p + C.m_c + B.m_b + T.m_t}, \tag{3}$$

where Al_p and Al_c are mass allocation for passengers and cargo, respectively. Pax, C, B, and T are the annual number of passengers, cars, busses, and trailers. Data

were obtained from the ship operator. The weights of the passenger and its luggage, car, bus, and trailer are shown by m_p, m_c, m_b, and m_t.

Equations (4) and (5) calculate the transport work for passengers and cargo.

$$TW_p = Pax.\frac{Dist}{Trip} \tag{4}$$

$$TW_c = Cargo.\frac{Dist}{Trip}, \tag{5}$$

where TW_p and TW_c indicate transport work for passengers and cargo. *Pax* and *Cargo* are the annual numbers of passengers and cargo weight; *Dist* and *Trip* refer to annual distance and number of trips. All the equations above are used to calculate emissions per transport work, as shown in Eqs. (6) and (7). Em_{pax} shows carbon emissions per passenger transport work (gram CO_2/pax-nm) and Em_c is carbon emissions per cargo transport work (gram CO_2/ton-nm).

$$Em_{pax} = \frac{EM_i.Al_p}{TW_p} \tag{6}$$

$$Em_c = \frac{EM_i.Al_c}{TW_c}. \tag{7}$$

Formulas similar to Eqs. (6) and (7) are used to calculate fuel consumption per transport work by replacing EM_i with fuel consumption.

3.5 Cost calculation

The cost elements include the annual fuel and carbon prices, since the study focuses on the impact of fuel choice and its implications for carbon emissions. The cost is calculated based on the annual energy consumption and fuel prices. Predictions of fuel price levels (Table 3) were mainly taken from previous studies (DNV 2022; Ship and Bunker 2023; Siu et al. 2022), complemented with estimates of experts (Sea\LNG Ltd 2020; Ship and Bunker 2022).

To illustrate the costs incurred from the emissions, we incorporate carbon pricing through taxation mode which is more straightforward and suitable for

Table 3 Fuel price prediction

Year	MDO/MGO (€/tonne)		LNG (€/tonne)		LBG (€/tonne)	
	Low	High	Low	High	Low	High
2023	677.7	919.4	769.9	1338.5	882.7	1721.3
2030	640.6	869.0	538.9	936.9	772.4	1522.7
2050	358.0	664.0	322.3	612.4	639.9	1301.9



Table 4 Different carbon taxation schemes

Tax scheme	Carbon price in different years (€/t-CO_2)	
	2030	2050
STEPS	57.5	79.6
SDS	106.1	176.8
NZE	114.9	221

our study. It provides ideas to ship operators regarding the possible economic implications of carbon pricing.

Three different carbon tax schemes were applied, namely stated policies scenario (STEPS), sustainable development scenarios (SDS), and net-zero emissions (NZE), as shown in Table 4 (Bui et al. 2022). STEPS follows the existing policies and measures under development; SDS aims to meet the Paris Agreement goal, while NZE is a path to reach net-zero carbon emissions by 2050.

The costs are calculated using Eq. (8).

$$Cost = F.F_p + C.C_p, \tag{8}$$

where F and F_p are fuel consumption (tonne) and fuel price (€/tonne), whereas C and C_p are CO_2 emissions (t) and carbon price (€/t-CO_2). Next, we impute the change in cost, associated with the fuel and carbon prices, in the passenger ticket. The calculation is done by comparing known information about the RoPax fuel cost in 2022, the mass of passengers and cargo, and the actual ticket price at the time (Table 2). There are different ticket types. For illustration, the tickets included in the calculation were for adult passengers, child passengers, and bus and car packages. The data from Shippax (2023) showed that fuel costs represented around 23% of total operating costs, and the profit was 11% of the revenue. Based on this information, the fuel costs charged on the tickets for the bus, adult passenger, children passenger, and car package were 34.65 €, 8.76 €, 3.87 €, and 35.67 €, respectively. The costs associated with fuel and carbon in the ticket are calculated using Eq. (9).

$$Cost_y = \frac{Costpax_y}{Costpax_{ref}}.Cost_{ref}, \tag{9}$$

where $Cost_{ref}$ and $Cost_y$ indicate the fuel cost charged onto the tickets in 2022 and the calculated ones in year y, respectively. $Costpax_{ref}$ refers to the total annual costs associated with fuel in the year 2022, and $Costpax_y$ shows the calculated costs associated with fuel and carbon in year y. All results are presented for 2023, 2030, and 2050 to provide insights on the dynamics between fuel costs and associated emissions costs.



4 Results

Several parameters were calculated following MRV requirements: fuel consumption per distance, fuel consumption per transport work, CO_2 emissions per distance, and CO_2 emissions per transport work (Fridell et al. 2018).

4.1 Fuel consumption

The study shows the results between 2023 and 2050, where the vessel operator determined the efficiency improvement trajectory and the fuel type. Fuel projections were reported as unit energy (MWh) converted into fuel in mass units; hence, the quantity of fuel consumption differs despite the same energy value.

Figure 2 shows the fuel consumption per distance (kg fuel/nm). MDO showed the highest consumption per distance compared to LNG, LNG & LBG, and LBG. This is explained by its lower calorific value compared to the other fuels. It is estimated that the calorific values of MDO, LNG, and LBG in MJ/kg are 43, 48, and 49.3, respectively (Bengtsson et al. 2011; Spoof-Tuomi and Niemi 2020). MDO consumption per distance was around 10–12% higher than in the other scenarios. The operator's trajectory plan for improving efficiency would bring fuel consumption down to about 23% in 2050 compared to 2023 in all scenarios.

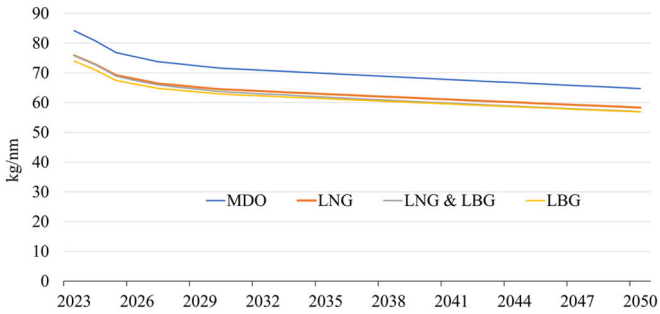

Fig. 2 Fuel consumption per distance

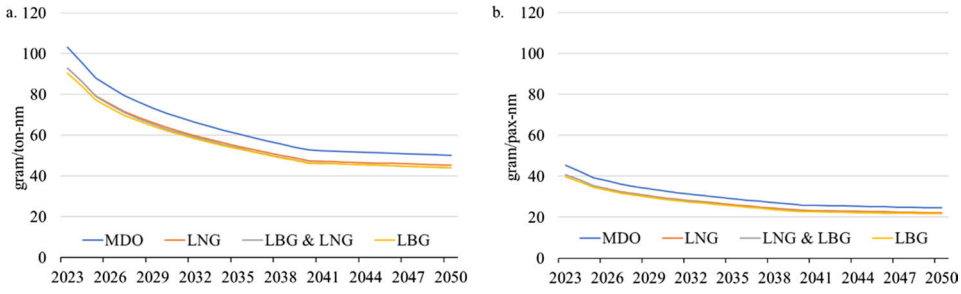

Fig. 3 Fuel consumption per transport work

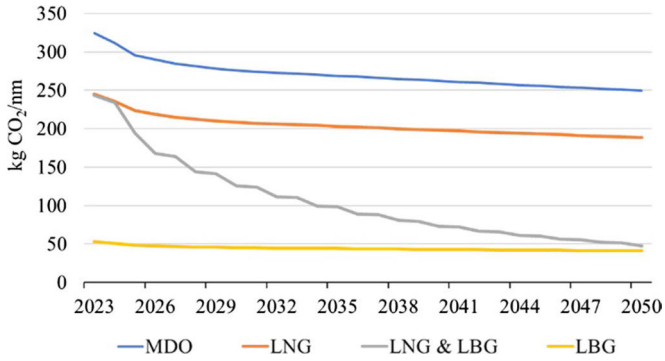

Fig. 4 CO_2 emissions per distance

Figure 3 presents the fuel consumption per transport work for cargo and passengers. The same pattern was found between fuel consumption per distance and transport work. MDO showed the highest consumption per ton-nm and pax-nm, 10–12% higher than other fuel types. Fuel consumption per ton-nm was about two times higher than the consumption per pax-nm. This was caused by the mass allocation method, which generated a higher burden for the cargo than the passengers and their accompanying vehicles. Allocation creates partitioning of input or output to distribute the impacts. From 2023 to 2050, calculations showed that the mass allocation for cargo and passenger ranged between 87–87.5% and 13–12.5%, respectively. The transition plan entails a fuel efficiency improvement that would reduce fuel consumption per transport work from 2023 to 2050 by 45% and 51% for passenger and cargo transport works across all scenarios (for a review of the reduction potential of various abatement measures, see Bouman et al. 2017).

4.2 Carbon emissions

MDO showed the highest carbon emissions per distance, followed by LNG, LNG & LBG, and LBG, as shown in Fig. 4. MDO consumption was only 10–13% higher than other fuels. However, the emissions of MDO per distance were much higher than other fuels.[2] Carbon emissions from MDO was 24% higher than LNG and 84% higher than LBG throughout the studied years. Carbon emissions from MDO varied between 25 and 81% higher than scenario 3 (LNG & LBG) throughout the studied years due to the stepwise addition of LBG into the fuel mixture. MDO and LNG are fossil fuels that cause higher environmental impacts than LBG. The total EF (gram CO_2 per MJ) during WtT and TtP for MDO, LNG, and LBG are 89.6, 66.5, and 10.7, respectively. Therefore, the pattern for the emissions per distance was different compared to fuel consumption per distance. This shows that the fuels have

[2] MDO has higher emission factors which are associated with higher emissions; moreover its heating value is lower in comparison to LNG or LBG.

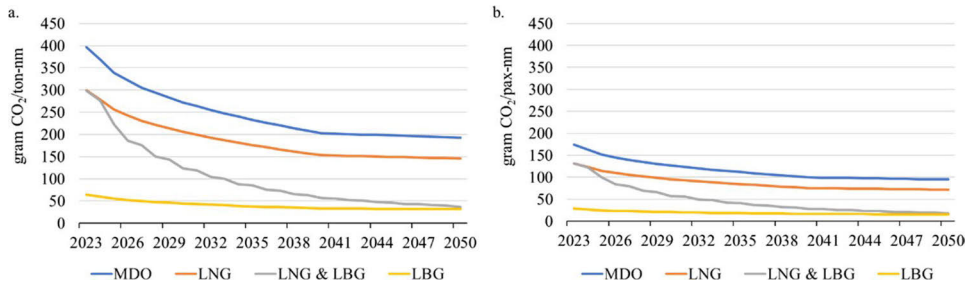

Fig. 5 CO_2 emissions per transport work

reasonably small differences in calorific value, while the carbon emissions among fuels are significantly different.

Figure 5 shows carbon emissions per transport work across all scenarios. Similar trends were found among the results of emissions per distance and per transport work, where MDO emissions was significantly higher than LBG. Mass allocation resulted in the emissions per (cargo) ton-nm being about two times higher than pax-nm. This number aligned with the comparison of fuel consumption per ton-nm and pax-nm (Fig. 3).

Contribution analysis was also applied to investigate which lifecycle stage contributes the most to emissions. Figure 6 displays (a) the average contribution analysis of CO_2 emissions across four scenarios from 2023 to 2050 based on lifecycle stage, and (b) the average contribution analysis of different emissions to climate change impact. Scenarios 1 and 2, where MDO and LNG were used, showed similar results. The main contributor was from the TtP stage, which accounted for about 83.7% and 84.2% of the total carbon emissions of MDO and LNG, respectively. Similar trends were shown by the average result of LNG & LBG, where TtP was the biggest contributor, covering 71% of total carbon emissions. The opposite pattern was found in LBG. The upstream WtT was responsible for 68% of its total carbon emissions, since carbon emissions during TtP was considered biogenic. The TtP emission contribution was mainly from the 5% MDO that was used as pilot fuel.

The contribution analysis also assessed the climate change impact per distance. The characterization factors for CH_4 and N_2O were 25 and 298, respectively (Statistics Netherlands 2020). It was found that N_2O was insignificant across the four scenarios. Different results were shown for CO_2 and CH_4, where the former gas was the

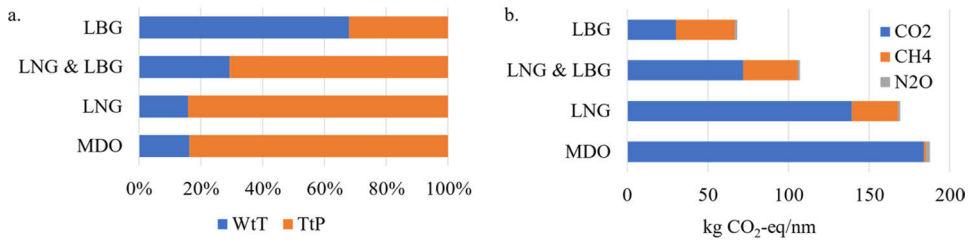

Fig. 6 Contribution analysis of **a** CO_2 emissions, **b** climate change impact

Table 5 Summary of fuel and carbon costs

Year	Fuel or carbon costs (STEPS, SDS, Net Zero)	MGO/MDO		LNG		LNG & LBG		LBG	
		Fuel (low)	Fuel (high)	Fuel (low)	Fuel (high)	Fuel (low)	Fuel (high)	Fuel (low)	Fuel (high)
2023	Fuel (€)	3,430,244	4,652,953	3,487,589	5,998,329	3,489,982	6,007,341	3,873,391	7,451,308
	STEPS (€)	0	0	0	0	0	0	0	0
	SDS (€)	0	0	0	0	0	0	0	0
	Net Zero (€)	0	0	0	0	0	0	0	0
2030	Fuel cost (€)	2,755,446	3,737,624	2,110,536	3,616,937	2,506,844	4,631,479	2,890,616	5,613,931
	STEPS (€)	970,249	970,249	875,475	875,475	609,773	609,773	352,475	352,475
	SDS (€)	1,791,229	1,791,229	1,616,261	1,616,261	1,125,734	1,125,734	650,722	650,722
	Net Zero (€)	1,940,498	1,940,498	1,750,950	1,750,950	1,219,545	1,219,545	704,949	704,949
2050	Fuel cost (€)	1,393,042	2,583,869	1,136,898	2,156,973	2,087,720	4,228,394	2,133,008	4,327,057
	STEPS (€)	1,215,273	1,215,273	1,096,565	1,096,565	471,271	471,271	441,488	441,488
	SDS (€)	2,700,607	2,700,607	2,436,812	2,436,812	1,047,269	1,047,269	981,084	981,084
	Net Zero (€)	3,375,759	3,375,759	3,046,015	3,046,015	1,309,086	1,309,086	1,226,355	1,226,355

main contributor to climate change in MDO and LNG, making up 98% and 82% of the total impact, respectively. Meanwhile, CH_4 was the main contributor to climate change in LBG. The total climate change impact from CH_4 was about 31% and 54% for LNG & LBG and LBG scenarios, respectively. The separate emissions of CH_4 and N_2O are shown in Supplementary material Table 3.

4.3 Economic impacts

This section discusses the economic implications of using different fuels and applying different carbon tax schemes. Table 5 summarizes fuel and carbon costs in the years 2023, 2030, and 2050. MDO had the narrowest high/low difference, with the largest being that of LBG. The results also indicate that the more renewable options were always more expensive than the fossil ones.

The carbon costs showed consistent trends among three schemes: STEPS, SDS, and Net Zero. Net Zero is the scenario that aims to reduce carbon emissions to zero by 2050, hence the highest carbon price. The results of carbon costs also corresponded positively with the emissions calculations, where the lowest was from LBG, followed by LNG & LBG, LNG, and MDO. The carbon price was also set to be higher in 2050 for each scheme, as displayed in Table 5. A complete illustration of total costs from the combinations of different fuel and carbon prices can be found in Supplementary Material Fig. 1.

There are different passenger ticket prices. We have price information, fuel cost, operating profit, and revenue for the year 2022. We use this information to estimate the share of fuel cost in total costs. Applying a similar method, complemented by calculations of fuel carbon cost in the future, we estimated the share of fuel and carbon costs in the ticket price (Fig. 7). The high price of fuel and Net Zero carbon price were used to calculate the change in ticket price. The high fuel price was applied because the values between the estimated fuel cost in 2023 and the actual fuel cost in 2022 reported by Shippax (2023) were aligned. The fuel cost associated

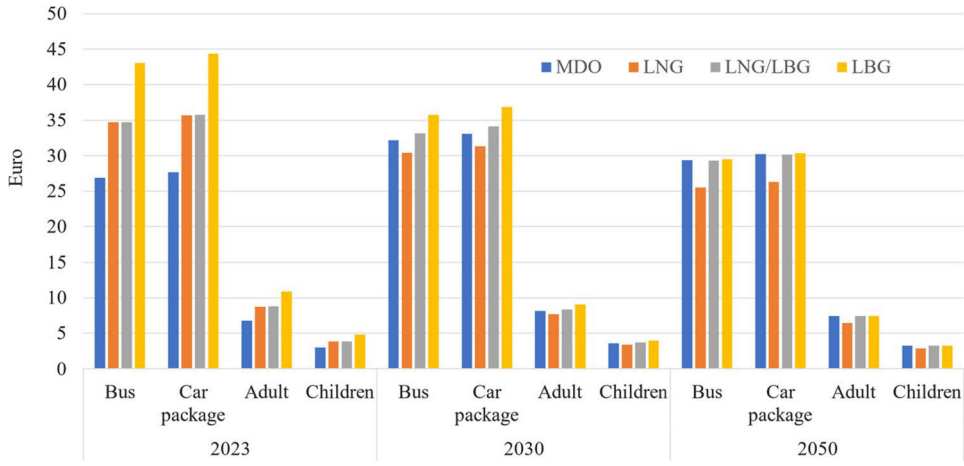

Fig. 7 Summary of the fuel and carbon costs' contribution in the tickets with the Net Zero carbon tax scheme



with passengers in the year 2022 was about € 778,185, while the estimated calculation for 2023 was € 778,931. The Net Zero scheme anticipated the highest possible cost incurred from carbon pricing.

The results indicate different trends among various fuel types. These differences were affected by the dynamics between fuel prices and carbon tax. Although fuel prices were predicted to decline in the future, the opposite trend was found with the carbon tax, which would increase with time. LBG will cause the highest costs until 2030 and level out with MDO in 2050. The opposite results are seen in MDO, with the lowest costs in 2023, becoming the most expensive option in 2050, due to the high costs associated with carbon emissions from MDO. Overall, LNG showed consistent costs, which were not the most expensive in 2023 and became the least expensive in 2023 and 2050.

5 Discussion

5.1 Environmental and economic impacts

Most vessels still use HFO and MDO, accounting for about 76% and 20% of total maritime fuel consumption, respectively (IMO 2021). At the same time, there is an increase in LNG demand in the maritime sector. This trend can be fuelled by climate change concerns and the European MRV legislation. Switching to LNG can reduce carbon emissions by 25%, compared with MDO. However, the overall climate change impact from using LNG is not significantly lower than MDO since LNG has higher CH_4 emissions due to methane slip (unburned methane) (see Fig. 6), although engine manufacturers are progressing in reducing the slip. These findings are also confirmed by previous studies (Brynolf et al. 2014a, b; Gilbert et al. 2018; Spoof-Tuomi and Niemi 2020). Shipping needs to switch to a renewable fuel option, such as LBG, to meet emissions targets and contribute in preventing the catastrophic effects of climate change. Although its methane emissions are as high as those of LNG, the CO_2 emissions is mainly biogenic and can considerably reduce overall climate change impacts. Even a stepwise introduction of LBG as a mixture with LNG can provide long-term climate benefits (Fig. 6).

However, ship operators do not necessarily have a strong incentive to change if carbon pricing is not high enough. Siu et al. (2022) reported that the switch from fossil to renewable fuels in the maritime sector will happen if the carbon pricing is no less than 213 €/ton CO_2, making the adoption of LBG and biomethanol likely in the late 2040s. Similar outcomes were found between those authors' model and our calculations, where we show that the transition will likely happen by 2050 only if the carbon pricing follows the net-zero scenario. Assuming the latter scenario is applied, the carbon costs of using MDO or LNG will range between 52–73 and 43–74%, respectively, depending on whether the fuel price is on the lower or higher side (see Fig. 7). The carbon costs of using a mix of LNG-LBG and LBG will be around 21–39% and 12–23%, respectively. The expensive carbon costs will likely make ship operators consider alternative fuels. Another way to address the issues is to introduce bunker levy schemes, as also considered by the IMO (Kosmas and



Acciaro 2017). However, opposite to carbon pricing, bunker levy schemes cause an increase in overall costs, leading to speed adjustments for fuel efficiency which in the long run is expected to drive the adoption of environmentally friendly technologies in shipping.

Introducing a carbon price within the maritime sector would increase fuel expenses, consequently raising voyage costs. Under the different assumptions on fuel types, fuel prices, and assumptions on carbon pricing between 9 and 45 €/ton CO_2 eq, the transport cost increased by about 0.4–16% (Rojon et al. 2021). An analysis of Danish cargo shipping suggests that a carbon tax between 350 and 450 €/ton CO_2 eq would be needed to meet the Paris Agreement and result in a 100% increase in cargo transport costs (ben Brahim et al. 2019).

Our results are between those of previous studies, considering the assumptions of carbon pricing ranged from about 57 to 221 €/ton CO_2 eq. As ferry operators face higher fuel costs due to the carbon tax, they may adjust their pricing strategy to cover these additional expenses. In the absence of competition, this can result in higher ticket prices for passengers and cargo. The extent of the price increase will depend on the level of the carbon tax, the efficiency of the ferry's fuel consumption, and competition in the ferry industry. In our case, the RoPax operator has the option to try to promote green travel or transportation and try transferring the increased fuel costs into the price of different types of passenger tickets, accompanying vehicles, cabins, and into lounge and cargo prices. This can of course make passengers opt for other modalities (road or air) and it can decrease the volume of goods being transported, resulting in an increase in the price of imported goods (Rojon et al. 2021). Previous studies have shown that the cost impact on the end products is very small, especially for the higher value-added goods (Schwartz et al. 2022; World Economic Forum 2021), often carried by RoPax vessels. Still, the impact of increasing shipping costs may have serious effects as, for example, shown by a recent analysis of possible modal shifts caused by sulphur regulation (Zis et al. 2019).

Our study moreover shows that the impact on passenger ticket prices is relatively higher and boils down to passengers' climate change concerns and willingness to pay. Recent evidence from the aviation industry shows that passengers' willingness to offset their carbon footprint for money remains low (Berger et al. 2022). However, carbon compensation has recently suffered from a bad reputation, and a direct offsetting mechanism may be more attractive to passengers. A low CO_2 footprint for cargo owners may even provide a competitive advantage, distinguishing their products from competitors using transportation with a higher CO_2 footprint.

Over time, as ferry operators adapt to the carbon tax and invest in cleaner technologies, the emissions associated with ferry travel could decrease, reduce the carbon tax burden, and potentially stabilize ticket prices in the long run.

5.2 Uncertainties

ISO 14040 defines allocation as *'partitioning the input or output flows of a process or a product system between the system under study and one or more other product systems'* (ISO 2006). Different allocations are commonly applied when dealing with



multiple inputs or outputs, such as economic or mass allocations (Baumann and Tillman 2004). The standard does not specify certain methods and lets users select between mass and area allocations (Finnish Standards Association 2013). However, applying different methods can yield different outcomes, as shown by Fridell et al (2018), where one method could generate a result that is six times higher than the other method; discrepancies between methods can even be as high as ten times (Backstrom 1999). No single scientifically correct method exists; hence, the method can be chosen based on consensus within the RoPax industry (Fridell et al. 2018). Consequently, comparison between results across different studies should be carried out carefully, considering the allocation methods used. This study applied mass allocation due to its straightforward manner and data availability. The area method will require more estimation, such as the area occupied by the passengers and their accompanied vehicles.

Other than methods, uncertainties in the value of variables could lead to results' variability across different studies in both environmental and economic aspects. For the environmental impacts, uncertainty can stem from emissions generated by different fuels. However, the source of differences is usually not difficult to trace and is usually related to the product life cycle stage, such as transport distance or different electricity mix between countries (Brynolf et al. 2014a, b; Spoof-Tuomi and Niemi 2020). Moreover, the LCT perspective requires practitioners to be transparent with all the data used and assumptions applied. Higher uncertainties emerged from the economic analysis since fuel prices are notoriously difficult to predict, especially when extraordinary events, like the pandemic, occur. The world shut down, and oil producers could not sell their products as demand plummeted, causing crude oil to reach negative price levels (Le et al. 2021). Hence, we introduced two fuel price levels and three carbon pricing schemes to provide comprehensive results showing different possible outcomes from economic uncertainties.

5.3 Fuel availability

Switching from fossil fuel to LBG will present a challenge, in view of the many uncertainties surrounding the potential of LBG in shipping. First, it is unclear how much LBG will be available, as this will depend on several factors, such as feedstock cost and availability, as well as the supporting policies (Energy Transitions Commission 2021). It has been predicted that feedstock demand would increase due to various human activities, likely leading to a rise in feedstock prices due to limited availability. Second, the level of competition between different biomass uses will determine the level of LBG production that will be shared between the power/heat sector and the transport sector (IEA Bioenergy 2017). Siu et al. (2022) reported that the current annual production of LBG is about 62,800 tonnes, produced from different sources such as biowaste, fishery waste, agricultural waste and residue, and landfill gas. It was shown that 73% of the total LBG was produced in Europe, and the remaining 23% was from the United States. In Finland, Gasum is the only player in LBG production; its annual production is around 4300 tonnes.



Due to its availability, blending LNG and LBG can serve as a transitional step towards a cleaner energy future, especially in sectors where transitioning directly to LBG might not be possible due to availability and infrastructure limitations (DNV 2019). These fuels can be mixed at any ratio (shown by scenario 3 in this study) according to availability, regulations, and price, which will determine the fuel's emissions reduction potential and overall environmental impact.

6 Conclusions

The environmental and economic aspects of employing diverse marine fuels alongside varying carbon pricing strategies have been examined. Our study explored different fuels namely MDO, LNG, a blend of LNG-LBG, and LBG. The results of emissions monitoring vary across different vessels; nevertheless, our methodology is transferable to other vessels, RoPax or not, and acceptable by MRV standards. We also emphasized transparency in data collection, methodology, and calculation. For example, the choice between mass and area allocation can cause significant differences in emissions, as we show, with cargo emissions from cargo being twice as high as those attributable to passengers. The public data of EU MRV (EMSA 2023) show variations in carbon emissions per nm and carbon emissions per transport work, without any specific pattern. Disclosing the monitoring plan, selected methods, and emissions are the basis of MRV aiming at decarbonization. Moreover, the impending requirement, set by the EU MRV, for separate reporting of CH_4 and N_2O emissions by 2024 could prompt ship operators to explore renewable fuel alternatives. The explored alternatives would not only decrease CO_2 emissions but also improve the impact of climate change.

Integrating carbon pricing will result in a rise in overall operating costs. In principle, it is more feasible to pass the costs to cargo than to passengers, given the lower price elasticity of the former and the rather limited share of transport costs in final prices. For bulkers and tankers instead, transport costs represent a higher share of final prices but, even in this case, the impact should be limited given the low price elasticity of the transported goods (commodities and oil).

LBG appears promising in addressing climate change caused by shipping, but its high CH_4 emissions still require technological solutions going forward. Moreover, biomass availability and competition among sectors vying for LBG can lead to price increases. Relevant stakeholders must reassess the balance between environmental impact, economic performance, and the trade-offs of future fuels and carbon prices. A potential solution involves gradually blending LNG with LBG and progressively increasing the LBG part. This approach could help mitigate environmental impact while addressing concerns about LBG availability and price fluctuations.

In a situation where fuel is scarce, a RoPax ship would be priority as it transports both passengers and cargo and, as a result, it could be used to ration fuel usage. It is also important to understand that, from a technological perspective, a dual-fuel engine gives operators a competitive edge, due to the ease of switching from one type of fuel to another (also known as fuel flexibility). On the other hand, fuel prices will continue to behave as those of any other commodity in a



free market. This means that the market forces of demand and supply of biofuels, especially LNG and LBG in this case, will obviously influence the prices and quantities of these fuels in future energy markets.

Our analysis assessed the situation up to 2050. In reality, unforeseen changes are likely to occur. Nonetheless, the study aligns with IMO strategy, hopefully benefiting shipowners, especially those in RoPax shipping, in their decisions on decarbonization. Future research can focus on other potential fuels, such as biomethanol or electrofuels. This is especially important since switching to methanol will require engine retrofit, leading to increased costs. Methane slip is another important issue of using LNG or LBG, and its elimination requires further research and development. On the side of economics, there may be merit in exploring ways for the logistics chain to bear the increased costs, and to assess the potential added value to end users from green transportation.

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Data Availability Not applicable.

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Techno-economic assessment of hydrogen application in cereal crop farming

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The application of hydrogen in modern farming is transitioning from a conceptual idea to a practical reality, poised to meet future agricultural machinery requirements and transition goals. Increasing tensions between farmers and various institutions underscore the growing sensitivity around fossil fuel dependency in the agricultural sector, particularly in northern economies. This study investigates the economic feasibility of using decentralized hydrogen systems to fully replace fossil fuels in cereal crop farming across four agricultural zones. Specifically, it examines the economic viability of on-farm hydrogen production using electrolysers to meet the fuel needs of different farm structures. Various scenarios were modelled to assess the impact of switching to hydrogen fuel for annual farm operations, using Net Present Value (NPV) and Levelized Cost of Hydrogen (LCOH) metrics for hydrogen refuelling facilities on distinct farm structures. The results indicate that economic feasibility is a significant challenge, with LCOH reaching as high as 57 €/kg of hydrogen in some cases, while the best-case scenarios achieved LCOH as low as 7.5 €/kg. These figures remain significantly higher than those for diesel and alternative fuels such as methane, FAME, and HVO. The study also assessed strategies for reducing hydrogen production costs using low-cost electricity and maximizing plant efficiency by increasing the electrolyser utilization rate to 70%. Additionally, the potential for revenue generation through the sale of by-products was explored. Our findings highlight both the challenges and opportunities associated with hydrogen use in agriculture, emphasizing the critical role of access to renewable energy sources and the economic limitations of by-product revenue streams. In conclusion, while decentralized hydrogen production can contribute to emission reductions in cereal crop farming, further research and policy support are essential to improve its feasibility and sustainability.

KEYWORDS

fuel consumption, hydrogen refuelling system, decarbonisation, agricultural machinery, hydrogen, crop farming

Introduction

The market for green hydrogen exceeded USD 9.6 million in 2023 and is expected to grow at a CAGR of over 31% from 2024 to 2032. The reason for this increase is due to the growing demand for cleaner fuel alternatives and concerns over carbon emissions. In the agricultural sector, hydrogen is already being used for tasks such as grain drying and cooling through hydrogen generators, and in specific farming machinery like electric tractors to

improve energy efficiency and reduce carbon emissions (Conklin, 2023). Supporting data from[1] Our World in Data (2020) places agriculture as the fourth largest contributor to *per capita* greenhouse gas (GHG) emissions, with a footprint of 0.75 tonnes of CO2 equivalent. This places agriculture just behind the leading sectors of electricity and heat production (1.94 tonnes CO2 equivalent), transportation (0.93 tonnes CO2 equivalent), and manufacturing and construction (0.79 tonnes CO2 equivalent), underscoring the importance of targeted emission reduction strategies in the agricultural sector to address its significant environmental impact.

Fuel consumption is a significant factor in modern agriculture, especially in crop farming, as it directly impacts the economic viability and environmental sustainability of farming practices. Agricultural field machinery currently relies almost exclusively on internal combustion engines, 75% of these engines in the US and EU are powered by diesel oil (Lagnelöv et al., 2020). Diesel oil, characterised by its high energy density and safe handling, is an indispensable energy source for agricultural machinery, particularly tractors. Tractors, harvesters, and drying machines are the primary fuel consumers on farms, making them critical contributors to the energy consumption of each farm (CEMA, 2022). Tractors, in particular, are the backbone of modern farms and are extensively used for tasks such as ploughing, planting, and harvesting, making them the primary consumers of farm fuel (Farias et al., 2017). Similarly, harvesters, used for reaping crops, require intensive fuel consumption over shorter periods, and they draw significant quantities during peak harvesting times. Therefore, evaluating energy usage on agricultural farms is imperative, given the growing concerns about energy prices in the current world market and the pressing need to reduce greenhouse gas emissions (Giampietro, 2003).

The transition to alternative fuel sources in off-road transport systems, such as farm tractors, has gained significant momentum in recent years. This shift, largely motivated by the desire to move away from traditional fossil fuels, encompasses the use of fuels like methanol and hydrogen, as well as the adoption of electrification through battery packs (Caban et al., 2018; Ewald Luger, 2021). These initiatives aim to foster more sustainable and environmentally friendly practices within the agricultural sector, where fuel is extensively utilized for transportation, operating tractors and machinery, and irrigation. The rising costs of fossil fuels have notably impacted the economics of crop production, especially for those crops heavily reliant on machinery operations with high fuel consumption (Stakens et al., 2023). This has led to a faster increase in production costs compared to other crops, driven in part by escalating fuel prices.

Simultaneously, there has been a significant evolution in regulatory frameworks aiming to curtail emissions from off-road diesel engines. This has resulted in the implementation of more stringent emission standards for agricultural machinery engines in Europe and the United States, as discussed by Tim and Aparna (2016). Consequently, these regulations have influenced farmers' crop choices, leading them to prefer crops that require less fuel to produce, thereby maximizing profitability (Safa and Samarasinghe, 2013). So far, the GHG emissions from offroad machinery have not been regulated. In October 2023, the Californian Air Resources Board announced that they are considering a 6% reduction in CO_2 emissions in their upcoming Tier 5 regulation.[2]

Our study acknowledges a dual challenge in the agricultural sector: its fuel energy footprint is both an environmental issue and the existing challenges with the use of alternative fuels at the farm can potentially lead to production- and economic problems at the transitioning farm. This duality intertwines the concerns of maintaining a stable food supply with the imperative of environmental protection which scrutinizes machinery use in the sector. While our research acknowledges these intertwined dilemmas, it primarily concentrates on exploring the decarbonization pathways within the sector. Offroad engine application have such pathways in common with other so-called hard-to-abate sectors, notably maritime transportation (Hellström et al., 2023). Lots of studies have recently been devoted to alternative fuels for ships, for which the production pathway typically builds on largescale, centralized production facilities (Seithe et al., 2020; Fan et al., 2021; Korberg et al., 2021). However, farm machinery applications offer an interesting opportunity to explore farm-scale, decentralized production of alternative fuels. For example, biogas has been studied extensively over the past decade or so. With the introduction of hydrogen engines, decentralized production has become an interesting option. To date, few studies have investigated hydrogen usage in agricultural machinery in a systematic way that incorporates the fuel usage patterns of agricultural machinery on farms. Most of these studies have been limited to investigating machinery powertrain transitioning by introducing new concepts of machinery that use different energy sources like batteries, Fuel cells, and modified engines that can accommodate different fuel blends. However, they have not sufficiently discussed the implications of adopting these new technologies from a farm operations level perspective.

In the dynamic landscape of agricultural innovation, where there's a burgeoning market for new tractor powertrains and machinery design is evolving to comply with stricter emission standards, hydrogen fuel emerges as a promising alternative. This transition to a certain degree is not solely about meeting environmental objectives; it also encompasses a crucial business dimension. The end goal of this transition is to achieve emission reduction while simultaneously ensuring that agricultural operations can be sustained economically amid escalating fuel prices and rigorous environmental mandates (Ewald Luger, 2021; CEMA, 2022). Therefore, the purpose of this study is to evaluate the environmental and economic sustainability of hydrogen technologies applied to farm-level agricultural practices.

The paper is organized as follows: it begins with an overview of decarbonization pathways and technologies currently implemented

1 https://ourworldindata.org/emissions-by-sector

2 https://dieselnet.com/news/2023/11carb.php

in the agricultural machinery sector, drawing on various literature sources. It then details the methodology used to assess fuel usage in agricultural machinery across different farm structures. The analysis further examines the implications of transitioning to a hydrogen-based fuel system in farms, concluding with a techno-economic assessment of the findings to establish the economic viability of renewable agricultural fuel systems in varying geographical farm settings.

Literature review

Decarbonisation of farming using hydrogen

Decarbonization options for agriculture encompass a broad spectrum of practices, ranging from crop rotation and precision farming to the adoption of renewable energy sources. Central to this transformation is the modernization of farm machinery – a shift from diesel-powered to electric or hydrogen-fueled vehicles and equipment (CEMA, 2022). New Holland (Germany-based manufacturer) introduced the second generation of its hydrogen-powered tractor, the NH2™, in 2012. This innovative model, built upon a conceptual design, employs a fuel cell to generate power for its electric drive train motors (Fuel Cells Bulletin, 2021). Despite the groundbreaking nature of this technology, infrastructure in Germany, like most other places, was not yet sufficiently developed to fully support the widespread adoption of such advanced machinery. This highlighted a broader challenge: transitioning to greener agricultural practices demands not just investment in cutting-edge technologies but also in the underlying infrastructure. The challenges posed by infrastructure, namely limited charging, and refueling points, as well as handling and storage issues related to hydrogen, have produced apprehensions regarding safety at refueling stations, which are essential to the successful implementation of these innovative technologies (Bhandari and Shah, 2021).

The production of hydrogen, which is pivotal for the clean energy transition in agriculture, is categorized into grey, blue, and green, reflecting the carbon intensity of each production method (Hermesmann and Müller, 2022). Grey hydrogen, produced from fossil fuels, is associated with high carbon emissions, whereas blue hydrogen mitigates this impact through carbon capture and storage techniques. Green hydrogen stands out as the most eco-friendly option, utilizing renewable energy sources to generate hydrogen through water electrolysis (Montenegro Camacho et al., 2017; EU Commision, 2022; Nasser and Hassan, 2023).

There is a possibility towards decentralizing hydrogen production, facilitating on-site generation at farms, not only addresses distribution challenges but also promotes sustainable agricultural practices (Janke et al., 2020). Despite its potential, this decentralized approach is impeded by significant obstacles, including high upfront costs, technological complexities, and substantial capital requirements for implementation (Fuel Cells Bulletin, 2021). Currently, hydrogen production is predominantly reliant on fossil fuel processes, such as steam reforming of natural gas (accounting for 76% of production) and coal gasification (23%), which contribute to greenhouse gas emissions (Aydin and Dincer, 2022; Hermesmann and Müller, 2022). However, there is a growing focus on shifting towards low-carbon hydrogen as a vital energy carrier, projected to increase its production capacity from 120 million tons per annum in 2020 to 530 million tons by 2050, highlighting its importance in achieving a low-carbon economy (Paris et al., 2021). This shift is crucial as scientists and policymakers alike recognize the need to reduce reliance on non-renewable energy sources and mitigate the environmental impacts associated with traditional hydrogen production methods (Dincer, 2012; IEA, 2019; Hermesmann and Müller, 2022).

Recent studies on the economic feasibility of farm-scale hydrogen production have shown mixed results, with the cost of hydrogen production and the required infrastructure investments being significant factors (Dincer and Acar, 2015; Aydin and Dincer, 2022; Breuer et al., 2022; EU Commission, 2022). This is primarily because authors have not been able to reach a uniform approach to solve the major challenges identified prior which have rendered hydrogen at present an unfeasible alternative due to the costs of technical requirements needed to facilitate its safe use in decentralized settings. Despite these challenges, the long-term benefits of transitioning to hydrogen, including reduced carbon emissions and lower operational costs, provide a compelling case for its adoption in farming (IEA, 2019).

Evaluating the feasibility of an on-farm fuel production system requires quantifying the amount of fuel consumed by the farm machines. However, it is equally important to consider the broader impact of fuel usage on the overall energy profile of the farming system. Research has shown that the emission footprint attributable to the use of fossil fuels by agricultural machinery ranges from 10% to 35% of total emissions from agricultural energy inputs, which encompass all energy used in agricultural operations in cereal crop farms were the majority of the studied cases (Dyer and Desjardins, 2003; Larry, 2008; Roberto Henke, 2021; Abbas et al., 2022a; Abbas et al., 2022b). Authors broadly agree that the factors influencing fuel consumption on a farm are varied, with machinery usage being a significant basis. Abbas et al. (2022b) underscores the significance of the notion of agricultural and environmental sustainability as a means of minimizing the depletion of natural resources while simultaneously increasing crop production. Consequently, thorough evaluations of energy resource inputs and outputs are crucial to ascertain the resilience and sustainability of a system (Abbas et al., 2022a).

Brynolf et al. (2018) identified a major challenge with alternative fuels for tractor engines: despite their lower power and energy output, they are costlier than standard diesel. To mitigate this economic barrier, farms could potentially adopt a strategy of localized/decentralized, small-scale production of fuels, particularly hydrogen, for their own use, as suggested by Janke et al. (2020). However, while Janke et al. (2020) examined the concept of decentralized hydrogen production, their research did not adequately address the diverse fuel usage patterns in different agricultural settings. Specifically, their methodology in designing hydrogen energy system modelling leaves room for debate, primarily because it did not adequately consider the variables that influence fuel consumption in agricultural

machinery across various settings. The reliance on generalized assumptions about annual tractor mileage, and consequently annual fuel consumption, may not accurately reflect the nuanced demand for hydrogen in the farming sector (Janke et al., 2020).

On-farm hydrogen investment requirement

Transitioning agricultural machinery to hydrogen fuel requires significant initial investments but offers considerable long-term economic and environmental benefits (Charles, 2021; CEMA, 2022). Concerning on-farm hydrogen applications, the upfront costs are dominated by the acquisition and installation costs of electrolysers, which are crucial for generating hydrogen from water using electricity. These setups, along with the necessary storage and compression facilities, can incur annual electricity costs of approximately $50,000 to $60,000, assuming the electricity is sourced externally rather than produced on-site systems (H. Mousazadeh et al., 2010; Carroquino et al., 2019; Charles, 2021). Studies have indicated that the costs of electrolysers range from $1,000 to $3,500 per kW for capacities between 1–10 MW in the United States and EU, with costs potentially dropping to $320–$400 per kW for larger scale electrolysers as capacity increases by 2030 electrolysers (Janke et al., 2020; Micena et al., 2020; Reksten et al., 2022).

Additionally, the capital costs for hydrogen fuelling standalone systems are increased by the need for auxiliary devices. These include a compressor unit costing €394,398, a cooling unit priced at €140,000, a dispenser at €107,000, and storage costs that vary with hydrogen tank size, ranging from €632 to €800 per kg of hydrogen depending on the supplier. These figures underscore the financial commitment required upfront, balanced by the promise of future rewards in sustainability and cost savings (Porter and Michael, 2014; Grüger et al., 2018; Bhandari and Shah, 2021).

Moreover, integrating renewable energy sources like wind parks and solar grids on the farm itself significantly boosts the economic viability of these hydrogen systems (Porter and Michael, 2014; Micena et al., 2020). This integration not only strengthens the business case but also utilizes the farm's existing resources to enhance sustainability and cost-effectiveness. Such operational efficiencies help amortize initial costs over time. Furthermore, producing hydrogen on-site for ammonia (NH_3) fertilizer can greatly reduce both fuel and fertilizer expenses, substantially lowering long-term operational costs. For example, a large 2800-acre US farm that annually spends $120,000 to $135,000 on fuel and fertilizers for dryland crop cultivation could see a reduction in operational costs by $38,000 to $67,000 through the implementation of solar photovoltaic systems for electricity generation (Charles, 2021). This approach not only ensures resource conservation but also offers significant financial savings, making it a compelling option for sustainable agricultural operations.

The major issue with existing research on hydrogen application in farming is the overgeneralization of fuel consumption patterns on agricultural farms. Case studies suggest that hydrogen fuel cells operate at an estimated efficiency of 57%, significantly surpassing the 45% peak efficiency of diesel engines (Lajunen et al., 2018). Yet, unlike diesel oil that can be easily stored on farm, hydrogen faces high storage costs. This implies that farms should utilize strategies that rely on spot usage and projected energy consumption. Therefore, our research methodology also takes into consideration the variation in these consumption patterns over different agricultural settings as will be detailed in the following section.

Overall, while the transition to hydrogen fuel in agricultural machinery requires high initial investments, particularly in technical equipment and energy solutions, it is expected to offer a viable path toward reducing long-term operational costs and fostering sustainable farming practices. The central guide to the execution of the study was to quantify the techno-economic implications of such systems being implemented by actual case farms in various settings, as will be elaborated in the next section.

Methodology

Research process

We conducted a detailed techno-economic assessment to evaluate the feasibility of producing hydrogen on a small scale and in a decentralized manner, as a sustainable and eco-friendly alternative to diesel fuel for farm tractors. To systematically address our research objectives, the methodology is structured around three principal steps:

I. Fuel consumption modelling: This step focuses on quantifying the fuel consumption and associated emissions of farm machinery within a calendar year. By considering variables such as geographic location, cropping practices, and land size, we aim to develop a predictive model that estimates the annual fuel needs and emission outputs of diverse farm structures, providing a granular understanding of their fuel energy profiles.
II. Dimensioning of the hydrogen production and refuelling plant: Building on the consumption patterns identified, the study progresses to the conceptualization of a hydrogen refuelling station tailored to each farm's specific requirements. The design criteria ensure the refuelling infrastructure can satisfy the entirety of the energy demands posed by agricultural operations, facilitated by an optimally sized electrolyser and a hydrogen storage system designed to offer a minimum two-day demand buffer.
III. Economic Analysis: The final facet of our methodology involves an economic evaluation, leveraging the concept of the Net present value to investigate the levelized cost implications for farms adopting hydrogen fuelling solutions. This analysis is critical for understanding the financial viability and environmental payoff of transitioning to hydrogen fuel, considering both immediate and long-term perspectives.

Fuel consumption modelling

This section of the study is structured to methodically examine such inputs and outputs for individual farms, much of this will not be discussed in this article as the topic has already been greatly

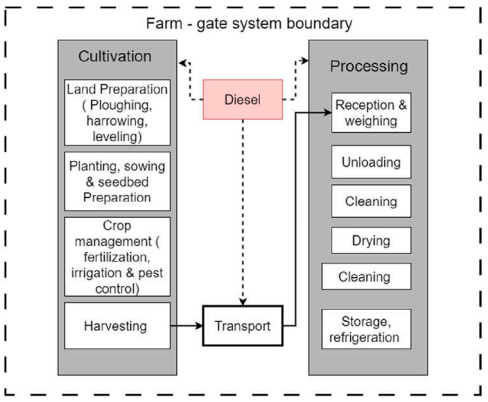

FIGURE 1
Farm - gate system boundary.

discussed by studies employing a life cycle assessment concepts (Weidema and Meeusen, 2000; Safa and Samarasinghe, 2013; Abbas et al., 2022a; Tihanov and Ivanov, 2021). While the focus on outputs has predominantly been on emission footprints, this study also scrutinises into the inputs, categorizing them into direct energy inputs (such as fossil fuels) and indirect energy inputs (including energy embedded in machinery, energy for fertilizer manufacturing, and electricity used for drying and irrigation). Contrary to including the whole farm energy profile, for the case of this study, the investigation only presents the findings of fossils (fuel + lubricant). This is because if green hydrogen is adopted as an alternative fuel, these types of emissions could be reduced by a factor of almost 100%. This comprehensive approach is designed to provide a holistic understanding of the energy dynamics within a farm structure in a farm-to-gate system boundary while analysing the operational aspects of fuel consumption by machinery used in crop farming.

When dealing with energy systems inform of fuels, not all farms have the same energy footprint much as they might be growing the same type of crop. Therefore, it is important that fuel use on different types of farms is analysed based on the farm operational activities that require agricultural machinery. Furthermore, the farmland ownership structure greatly influences the emission footprints and thus should be included when policies are being implemented to achieve equality in responsibility sharing by different farm holders.

System boundary definition

In establishing the system boundary for this research, as illustrated in Figure 1, we focused on the operational dimensions of fuel consumption associated with machinery employed in crop farming. This encompasses a range of activities, starting from field preparation (cultivation) through to the post-harvest processes (processing), specifically for crop farms. The choice to centre on cereal crops for this study is driven by their significant contribution, accounting for more than 70% of global crop production (Fantin et al., 2017).

Scenario development

To undertake a meaningful study with so many variables (location, type of crop, farm structure, machinery fleet etc), four case scenarios were developed.

The categorization of farm structures in this study adheres to the EU[3] criteria for farm ownership, which is predominantly based on the size of the land. Under this classification, farms are categorized as small-holder if they utilize less than 15 hectares (ha), medium-scale if they range between 20 and 50 ha, medium-intensity if they span 50–150 ha, and intensively mechanized if they exceed 150 ha (EU, 2020).[4] This classification also considers the diversity in farming practices that arise due to regional climatic conditions, agricultural legislation, and mandates, even though the focus is on the same types of crops.

The scale of agricultural operations, ranging from small family-run farms to large commercial enterprises, can impact fuel consumption patterns. Smaller farms, often limited by resources such as land size, typically rely on manual or traditional farming methods. However, for this study, we assumed data on farm machinery intensity per scenario. More importantly, it is evident that larger farms with more land are likely to have a greater number of machinery pieces than smaller farms. Therefore, it is crucial to consider this assumption. To accurately reflect the differences in farm operations, the scenarios developed in this study are based on farmland distribution data from Eurostat. This allows us to capture the true demographics of the national agricultural industry in the selected regions.

As detailed in Table 1, the study includes scenarios of small-holder farms in Italy, medium-scale farms in Germany and Sweden, and large, intensively mechanized farms in the United States. The crops selected for focus in this study are wheat, maize, and barley, which are significant contributors to global arable farming. This methodological approach enables a detailed understanding of how fuel consumption varies across different types and sizes of farms, within the context of diverse agricultural practices and policies.

Modelling machinery operations

Under this section of the research, we conducted a detailed investigation into the fuel consumption patterns associated with a variety of crop farming practices, structured across different scenarios to capture the nuances of crop seasons, farming techniques, and regional variances. This analysis was grounded in an evaluation of the fuel footprint linked to the operation of agricultural machinery, particularly tractors, through various stages of farming activity (refer to Figure 2). Drawing upon the foundational work of Grisso et al. (2003), Šarauskis et al. (2014), and Tihanov and Ivanov, (2021), we categorized farming operations into five key areas based on their energy demands and operational phases: land preparation, planting and seedbed preparation, crop management, harvesting, and post-harvest processes.

3 https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Farms_and_farmland_in_the_European_Union_-_statistics

4 https://www.europarl.europa.eu/RegData/etudes/ATAG/2020/659325/EPRS_ATA(2020)659325_EN.pdf

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TABLE 1 Scenarios based on the selected farm geographical locations.

Scenarios	Country	Crops	Farm structure	Farm machinery
Sc1-I	Italy	Wheat, Maize	Small holder	2WD, 4WD
Sc2-G	Germany	Wheat, Maize	Medium Scale	2WD, 4WD
Sc3-S	Sweden	Wheat, Barley	Medium Intensity	2x2WD, 2x4WD
Sc4-U	United States	Wheat, Maize	Intensive (mechanized)	3x2WD, 3x4WD

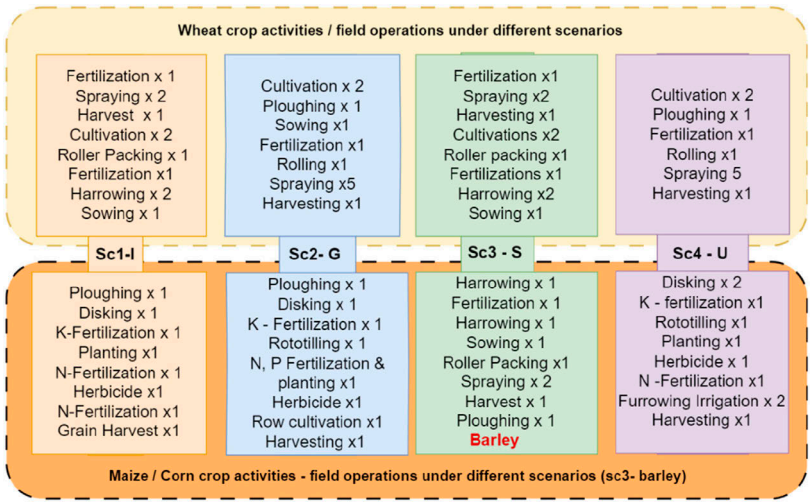

FIGURE 2
Crop activities/field operations for each scenario (Sc1, Sc2, Sc3 and Sc4).

For land preparation, including tasks such as ploughing, harrowing, and levelling, our methodology pinpointed the necessity for machinery within the 90 kW–130 kW power class, a decision informed by literature that emphasizes the significant influence of soil properties and machinery efficiency on fuel consumption (Klöckner, 2020; Paris et al., 2022; The U.S.Department of Agriculture (USDA), 2022). The subsequent phase of planting and seedbed preparation was noted for its shift towards precision, requiring machinery on the lighter end of the spectrum (<50 KW) and underscoring the differential fuel use driven by operational precision and duration.

In addressing crop management practices—fertilizing, irrigation, and pest control—our approach leveraged insights from the European Union's Common Agricultural Policy (CAP) as a framework for integrating eco-friendly practices through precision agriculture (Balogh, 2023). This included the deployment of 2WD tractors equipped with variable-rate technology, optimizing fuel consumption by adjusting to soil-specific needs, even if with a marginal increase in fuel use due to the technology itself.

Harvesting was identified as a particularly fuel-intensive stage, with combine harvesters at the forefront of operations in large-scale farming contexts, such as those prevalent in the United States (The U.S.Department of Agriculture (USDA), 2022). Our analysis here was enriched by examining how the volume of crops harvested, field terrain, and crop moisture levels collectively impact fuel efficiency, reflecting on the complex dynamics highlighted by Klöckner (2020) and Paris et al. (2022).

Lastly, the post-harvest phase, which includes drying, storage, and transportation, was scrutinized for its fuel consumption implications. Drying and storage does not belong to the category of offroad (mobile) machinery, but hydrogen could be used for those operations and hence (positively) impact the hydrogen economy of the farm. Emphasizing the critical role of strategic planning in reducing carbon emissions during transportation—a key concern under the EU's Green Deal—our study assumed for the utilization of heavy-duty 4WD tractors for these energy-demanding tasks.

By integrating these diverse strands of literature and analysis, our methodology offers a nuanced understanding of fuel consumption across the agricultural cycle, positioning our study as a significant contribution to the discourse on agricultural sustainability and efficiency. Through this comprehensive examination we were able to trace fuel usage in accordance with agricultural machinery and crop stages across all scenarios under our scope of investigation.

Fuel consumption model

A mathematical model is developed to estimate annual fuel consumption for various crop practices (refer to Equation 1). To create an accurate model, it is essential to identify and consider the significant factors that influence fuel usage. The model incorporates variables such as land area allocated for each crop, the number of operations per crop type, fuel consumption per operation, and machinery efficiency. For this study these are the factors that were selected; the type of operation being carried out, the type of crop being planted, the size of the farm, the type of machinery used per distinct operation, the frequency and duration of operations, as well as machinery fuel consumption patterns under similar operations. By considering these variables, we can model fuel consumed by each farm under each scenario.

$$F = A \cdot \sum_{i=1}^{n} (f_i \cdot r_i \cdot M_i) \quad (1)$$

F: Annual farm fuel consumption
A: Total land area allocated for each type of crop
n: Number of operations for each crop type (from land preparation to harvesting from the field)
f_i: fuel consumption per hectare for i-th field operation (litres per hectare)
M_i: Selected agricultural machinery (2WD or 4WD) fuel consumption per hectare (based on tractor standard field test)
r_i: Number of treatments an i-th field operation is carried out per crop season

The fuel estimation model presented here is a simplified version that aims to provide an estimate of fuel consumption for tractors used in farming operations. However, it is important to note that this model does not consider certain agronomic factors such as weather, soil type, and machine age/technicalities, which can have a significant impact on fuel consumption.

The data used for tractor fuel consumption per field activity was collected from a variety of sources including secondary sources, case studies, and standard field performance tests from DLG[5] (Deutsche Landwirtschafts-Gesellschaft – German Agricultural Society). These sources have already accounted for the agronomic characteristics while providing performance metrics during field operations in various locations. As a result, this model can be considered a linear model for fuel estimation, applicable to farms growing the same crops in different geographical locations. It is important to keep in mind that this model is not an all-encompassing solution for fuel estimation. Rather, it provides a basic estimate that can be used as a starting point for further analysis and optimization of fuel usage in farming operations.

Hydrogen refuelling station component sizing and dimensioning

Methodology

A hydrogen refuelling station comprises several key components, including an electrolyser, compressors, hydrogen tanks, a dispenser, and a pre-cooling unit (PCU), each playing a crucial role in the fuelling process as described briefly in 5. Compressors, especially piston compressors as noted in this study, are essential for elevating hydrogen pressure from low levels in storage to the higher pressures necessary for fuelling operations, a process highlighted by Micena et al. (2020). Maintaining the purity of hydrogen during this compression is critical, as emphasized by Grüger et al. (2018), given its application as a pure fuel source in vehicles. The selected piston compressor in this study is assumed to increases the pressure from 1 MPa to a discharge pressure of 90 MPa, aligning with the electrolyser's output and meeting the SAE J2601 standard, which sets the maximum pressure for Class 70 refuelling stations at 87.5 MPa as greatly detailed by studies (Grüger et al., 2018; Micena et al., 2020; Šimunović et al., 2022).

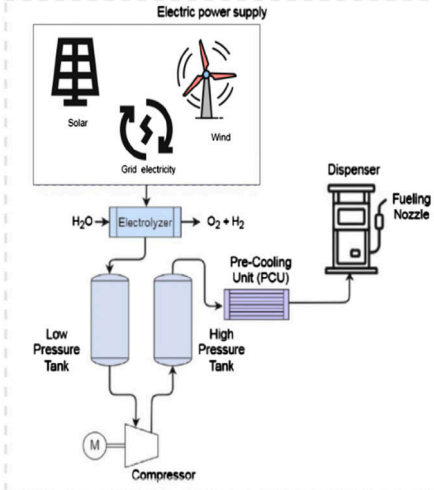

FIGURE 3
Schematic outline of a hydrogen component setting Sources: Micena et al., 2020.

This research, therefore, adopts a two-tiered approach to hydrogen storage, mirroring the design suggested by Grüger et al. (2018). Initially, the hydrogen is stored at low pressure, serving as a buffer, and ensuring a consistent flow to the compressor (Grüger et al., 2018). This low-pressure tank, directly linked to the electrolyser's output, maintains the initial pressure level (Grüger et al., 2018). Post-compression, the hydrogen is stored in a high-pressure tank, ready for use during peak demands and operating at the same 90 MPa pressure as the compressor's output (Micena et al., 2020) (refer to Figure 3). The dispenser and pre-cooling unit (PCU) are governed by the industry-standard SAE J2601 protocol, as detailed by Janke et al. (2020) and Šimunović et al. (2022). This protocol stipulates that hydrogen's temperature must not exceed 85°C during refuelling. Consequently, when compression increases the hydrogen's temperature, cooling is required to prevent overheating. The system targets a pre-cooling temperature

5 https://www.dlg.org/en/agriculture/tests/dlg-awards-explained

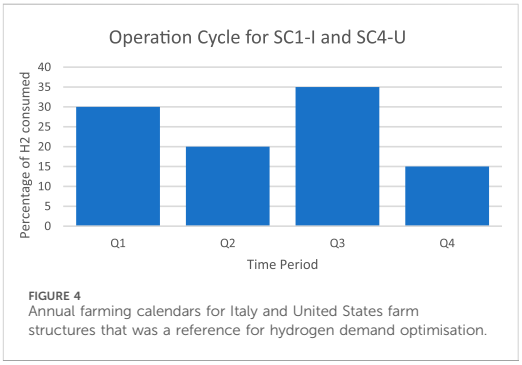

FIGURE 4
Annual farming calendars for Italy and United States farm structures that was a reference for hydrogen demand optimisation.

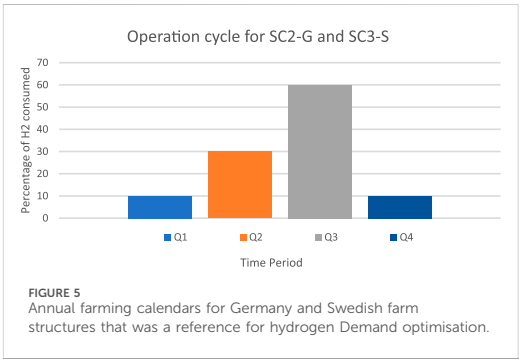

FIGURE 5
Annual farming calendars for Germany and Swedish farm structures that was a reference for hydrogen Demand optimisation.

of −40°C for refuelling at 70 MPa (Micena et al., 2020). Equipped with a pre-cooling unit, hose, and nozzle, the dispensing system facilitates the transfer of cooled hydrogen into the vehicle's tank, ensuring efficient and safe refuelling.

Hydrogen refuelling plant optimization

Our methodology involves optimizing the sizes of electrolysers and hydrogen storage tanks to meet the energy demands of agricultural operations. We employ a heuristic and iterative approach, tailoring hydrogen production to the fluctuating demand schedules across different farming cycles and geographic regions as shown in the Figures 4, 5. The goal is to balance production efficiency with storage capacity, ensuring a continuous hydrogen supply, particularly during peak agricultural periods.

H2PT component modelling

Operation Cycles (OC): Assumptions for operation cycles were based on regional weather patterns and agricultural activities. In SC2-G and SC3-S, we assumed a split usage of hydrogen, 10% of the annual fuel consumption in the first + fourth quarter due to winter seasons while 30%, 60% is consumed in the second, third quarter respectively (refer to Figure 5). In addition, for SC1-I and the SC4-U we assumed that they consume hydrogen quarterly, with the consumption being distributed as 30%, 20%, 35%, and 15% across the four quarters as depicted in Figure 4. Similarly, to SC2-G and SC3-S, these countries also have 40 non-operational days per year. Based on the assumptions detailed above, Equation 2 was used to model daily hydrogen demand of these different scenarios as a first step towards hydrogen storage tank size modelling.

$$Daily\ demand\ (OC) = \frac{\%age * Total\ H2}{Total\ days\ in\ a\ year - non\ Agricultural\ Operational\ days} \quad (2)$$

Daily Hydrogen Demand and Component Sizing: This involved calculating the operational days for a hydrogen-powered tractor (8 h a day, 5 days a week) and determining the minimum required production capacity of the electrolyser and storage capacity of the tanks. Maximum daily hydrogen demand was computed to ascertain the minimum electrolyser production capacity and storage tank size (Equations 2–5).

$$Max\ Daily\ H2\ Demand = max\ (Daily\ Demands\ for\ each\ operation\ period) \quad (3)$$

$$Electrolyzer\ Size\ (kW) = \frac{Max\ Daily\ H2\ Demand}{Electrolyser\ Daily\ hydrogen\ demand} \quad (4)$$

$$Tank\ Size\ (kg) = Max\ Daily\ H2\ Demand \times Days\ of\ Buffer \quad (5)$$

Economic analysis

The system's economic viability was assessed using two principal financial indicators: the Levelized Cost of Hydrogen (LCOH) and the Net Present Value (NPV). LCOH is pivotal for optimizing the configuration of the Power-to-Hydrogen (PtH2) plant, particularly concerning the electrolyser's capacity and hydrogen storage capacity. Conversely, NPV helps compare the financial aspects of a hydrogen-based system with those of a traditional diesel-powered system. Determining the NPV is critical for understanding the financial ramifications of transitioning to a hydrogen fuel system in agricultural settings, notably for operations involving machinery in crop farming such as wheat, maize, and barley. These indicators were utilized to build a functional model to compute the financial and economic results summarized in the next section.

Operationalization of the functional model

The models used in this analysis integrate financial projections and economic assessments. The computational steps taken to arrive at the results are as follows:

i. When calculating energy requirements and costs, this model assesses the economic feasibility of adopting hydrogen as an alternative fuel, by computing for capital requirements, both variable and Fixed operational costs associated with producing the targeted hydrogen demanded/needed by each farm annually to fully cover its fuel needs on site using the average spot prices of electricity in each locations/scenario.

ii. Using projected future electricity prices under each scenario, the model is improved to create a best-case scenario that farms could operate under if the Utility Rate (UR) of the hydrogen refuelling station across all scenarios is improved to reach 70% by selling off excess hydrogen at the same targeted hydrogen price which is 3€/kg across all scenarios. Furthermore, under this setting, the financial revenues are improved by incorporating assuming a best case scenario at which these stations could operate given that future renewable energies are projected to have an impact on future hydrogen prices. Under this we also considered discussions about possibility of earning extra revenues through if farms could sell off by products like oxygen and recovering thermal heat to industry partners as recommended by (Janke et al., 2020).

iii. The financial analysis part of the study is carried out using NPV and LCOH for each individual scenario using the collected economic parametric data.

Formulas

To calculate the NPV, we need to estimate the annual savings or revenue and subtract the OPEX for each year, then discount these annual net savings back to the present value using the discount rate (refer to Equation 6).

$$NPV = -CAPEX + \sum_{t=1}^{n} \frac{Annual\,Savings - OPEX}{(1+r)^t} \tag{6}$$

where:

- n is the number of years (15 years in this case).
- r is the discount rate.

Annual Savings would be the value of the hydrogen produced each year if it were to be sold or the savings from not purchasing diesel. OPEX is the annual operational cost.

The LCOH is calculated by dividing the total discounted cost (CAPEX + OPEX) by the total discounted hydrogen production over the system's lifetime (refer to Equation 7).

$$LCOH = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{7}$$

- I_t, Investment cost
- M_t, Maintenance cost
- F_t, Fuel cost
- Et, Energy produced
- r, Discount rate
- t, Lifetime of the project

Assumptions and input data

The economic parameters outlined below are applied to analyse the Net Present Value (NPV) and Levelized Cost of Hydrogen (LCOH) for decentralized hydrogen production facilities on farms in Italy, Germany, Sweden, and the United States. These parameters include essential financial and technical metrics that underpin the evaluation of the profitability and viability of such systems in different national contexts.

General Parameters.

- Lifetime (n): The assumed operational lifespan of the hydrogen production system is consistently set at 15 years across all countries.
- Interest on Capital: A uniform interest rate of 3% is applied, reflecting the cost of capital for financing the equipment required for setting up a hydrogen refuelling station. This figure also sets a consistent risk margin that is associated with the fragility of these kinds on investments which are mostly considered to be new technologies in the markets.
- Electrolyser Capacity: Varies significantly by country, with capacities ranging from 50 kW in Italy to 350 kW in the United States (refer to Table 2). The capacity variations in electrolyser capacities were optimised to suit the hydrogen demand profiles of the farms under study.
- Hydrogen Storage Tank Size: Similarly, storage capacities differ, with Italy at 20 kg and the United States at 400 kg, indicating differing scales of hydrogen storage capability. The tank sizes were optimised to keep a buffer storage of 2 days under each scenario to meet variations in fuel consumption during peak demand during operational seasons. Furthermore, hydrogen has higher costs of storage due to the energy consumption during storage and thus the logic is to store enough fuel to avoid operational constraints rather than storing the total annual fuel needed for farm operations as it is common with diesel fuel.
- Target Annual Hydrogen Production: Targets are set based on country-specific demands and capabilities, ranging from 806 kg/yr in Italy to 45,518 kg/yr in the United States. These targeted hydrogen quantities are energy equivalents from the Annual diesel fuel consumed under each scenario as investigated in 5.
- Targeted Selling Price of Hydrogen: A standardized price of 3 €/kg is used across all countries to estimate revenue from hydrogen sales. This price was chosen as an ideal selling price that would make hydrogen competitive with fossil fuels and other alternative fuels.
- Discounting Rate: Reflects country-specific financial environments (for our case we used the average 10[6]-year bond interest rates), with rates from 4.09% in Italy 2.42% in Sweden.

Assumptions For capital expenditures (CAPEX)

Under economic modelling of hydrogen production, a detailed assessment of capital expenditures (CAPEX) was performed using the data in Table 3. This assessment included costs associated with key components necessary for the setup and operation of hydrogen production facilities. The economic cost data used was collected from secondary literature sources including feasibility reports, and articles that have already extensively researched the implications of developing hydrogen refuelling stations in the countries understudy

6 https://www.treasurydirect.gov/savings-bonds/i-bonds/i-bonds-interest-rates/

TABLE 2 Economic data for the hydrogen fuel stations.

Plant operation parameter	Italy	Germany	Sweden	United States	
Lifetime, n (Year)	15	15	15	15	years
Interest on Capital	3	3	3	3	%
Electrolyser Capacity	50	170	110	350	kW
Hydrogen Storage tanks size	20	180	120	400	kg
Target Annual hydrogen to be produced	806	9,716	6,080	45,518	kg/yr
Targeted selling Price of H2 (6)	3	3	3	3	€/kg
Discounting rate	4.09 (1)	2.52 (8, 9)	2.42 (11)	3.63(9, 12)	%

TABLE 3 Capital expenditure for hydrogen fuel stations investment requirements.

CAPEX for hydrogen system	Italy	Germany	Sweden	United States	
Electrolyser (€)	1,100 (1)	1,000 (9)	970 (11)	1,450 (13)	€/kW
Stack replacement costs %age of elec. Capex (€)	15	15	15	15	%
Storage Tank (250bars) low Pressure tank	200 (3)	200 (3)	200 (3)	200 (3)	€/kg
Compressor	(<10 kW) 6,700 (1)	300,000 (10)	Scaled @ Factor 0.6 (10)	Scaled @ Factor 0.6 (10)	€
Dispenser + Chiller (€)	170,000 (4)	170,000 (4)	170,000 (4)	Scaled @ Factor 0.6 (10)	€
Installation and Permitting	15% of the capital equipment cost			Scaled @ Factor 0.6 (10)	

to reflect national market prices of these components however, some parameters were applied uniformly across all scenarios as follows.

- Electrolyser Costs: The electrolyser, a crucial component for hydrogen production, exhibited country-specific costs per kW. The costs ranged from 970 €/kW in Sweden to 1,450 €/kW in the United States, significantly impacting the initial investment required for each location.
- Stack Replacement Costs: These costs were uniformly set at 15% of the electrolyser CAPEX across all countries. This assumption ensures a standardized approach to accounting for maintenance and part replacements in the 8 years which is essential for continuous operation.
- Storage Tank Costs: For 250 bar low-pressure storage tanks, the costs were consistent at approximately 200 €/kg across all countries. This consistency facilitates comparability and uniformity in evaluating storage solutions.
- Compressor Costs: There was significant variability in compressor costs, with Italy incurring a relatively low cost of 6,700 €, while Germany's costs scaled based on a factor of 0.6, reflecting the larger systems used.
- Dispenser and Chiller Costs: These were uniformly set at 170,000 € except for the United States, where costs were scaled to account for the higher capacities used.
- Installation and Permitting Costs: These were calculated as 15% of the capital equipment cost, with specific scaling factors applied in different countries to reflect local regulatory and installation requirements. The figure was reached due to the regulatory frameworks that are in existence to avert risks associated with safety operations thus requiring specialised technical expertise for installation of the system which some cases assume to range between 10%–12% whereas 5%–3% was to cover the initial permitting costs by local authorities (Proost, 2019).

Assumptions For operational expenditures (OPEX)

Operational expenditures (OPEX) were analysed to understand the ongoing costs associated with the hydrogen production facilities refer to Table 4. These costs encompass electricity prices, maintenance, and operational overheads, among other factors.

- Electricity Prices (Average Spot Prices 2023): There was significant variability in electricity prices, ranging from 40 €/MWh in the United States to 126.766 €/MWh in Italy. These prices directly influence the operational costs, as electricity is a primary input for hydrogen production via electrolysis.
- Electrolyser OPEX: Uniformly set at 50 €/kW across all countries, this cost covers the maintenance and operational overheads of the electrolysis units. This ensures a standardized assessment of the operational costs associated with the electrolysers.
- Storage OPEX: Consistent at 5 €/kg, this cost was applied uniformly across all countries to ensure a standardized evaluation of the operational costs associated with hydrogen storage.
- Dispenser and Chiller Costs: Set at 5,350 € uniformly, except for the United States where scaled results were used to reflect higher capacities and usage rates.
- Compressor OPEX: These costs varied, with a fixed cost of 15,000 € in Germany and scaled results in other countries, reflecting the differences in compressor capacities and operational demands.

TABLE 4 Operational expenditure for hydrogen fuel systems in different scenarios.

OPEX for hydrogen system	Italy	Germany	Sweden	United States	
Electricity Prices (Average Spot Prices 2023)	126.766	95.18	46.47	40	€/MWh
Electrolyser	50 (3)	50 (3)	50 (3)	50 (3)	€/kW
Storage	5 (3)	5 (3)	5 (3)	5 (3)	€/kg
Dispenser + chiller (€)	5,350 (4,7)	5,350 (4,7)	5,350 (4,7)	Based on scaled result	€
Compressor	4% of CAPEX	15,000 (10)	Based on scaled result	Based on scaled result	€

By standardizing these assumptions across different countries, the study ensures a consistent framework for evaluating the economic costs associated with operating these systems. This approach allows for comparability and reliable assessment of the potential financial outcomes associated with transitioning to hydrogen-based systems in agricultural settings.

Modelling a possible best scenario from the first economic model

Proost, (2019) underscored the critical role of annual operating hours (load hours) in determining the cost of electrolytic hydrogen. The study revealed that low operational times (<2000 h per year), even with zero electricity costs, would result in hydrogen prices exceeding 10 €/kg, a finding that is both surprising and counterintuitive. Given that the electrolyser capacities across various scenarios, it is evident that the target annual production capacities do not achieve a utilization rate of even 40% except for United States.

The European Hydrogen Roadmap anticipates that the hydrogen economy will be supported by an abundance of cheaper renewable electricity, driven primarily by the increased adoption of wind and solar energy. These renewable sources are projected to contribute more than 15% of grid electricity by 2030 and 65% by 2050 (EU Hydrogen Road Map, 2019). Janke et al. (2020) highlighted the potential for farmers to use renewable electricity from sources like wind to produce hydrogen for farm machinery, benefiting from lower electricity costs. Additionally, the authors proposed that such hydrogen systems could generate extra revenue through waste heat recovery and selling oxygen to industrial consumers, thereby enhancing the profitability of these projects users (Janke et al., 2020).

These perspectives formed the basis for creating a best-case scenario in this study, which accounts for several factors: increasing the utilization rate (UR) of each electrolyser to 70%, reducing electricity prices based on future projections of cheaper renewable energy due to increased investments, and incorporating a subsistence production model where excess hydrogen is sold to other end. This comprehensive approach aims to provide a more accurate and optimistic assessment of the economic viability of decentralized hydrogen production systems on farms (refer to Table 5).

Results

Fuel consumption modelling

The results from our study are present in Table 6 and provide an insightful overview of diesel fuel consumption for wheat and maize cultivation across four scenarios (Sc1-I, Sc2-G, Sc3-S, Sc4-U), measured in total litres and efficiency (litres per hectare, L/ha). In Sc3-S, the fuel consumption of barley is considered. This is because the Swedish weather partners do not typically favour maize or corn, so farmers often plant barley as a cover crop. The analysis aims to provide a better understanding of fuel efficiency and consumption in agricultural practices.

Sc1-I exhibits the lowest total annual fuel consumption at 2,685 L, with wheat and maize requiring 104.5 L/ha and 109.3 L/ha, respectively. This scenario indicates relatively efficient fuel use, possibly due to less intensive land use. The total land utilized amounts to 25 ha, split between wheat (10 ha) and maize (15 ha).

Sc2-G shows a higher total fuel consumption at 34,967 L, with wheat at 142.2 L/ha and maize at 134.6 L/ha. The increased fuel use per hectare in this scenario suggests more fuel-intensive agricultural practices. The land utilization significantly jumps to 232 ha, with wheat cultivated on 152 ha and maize on 80 ha.

Sc3-S includes barley and demonstrates a total fuel consumption of 20,264 L, with wheat using 80.6 L/ha and barley 79.8 L/ha. The inclusion of barley and its comparative fuel efficiency to wheat in this scenario highlights potential crop-specific agricultural practices influencing fuel consumption. The total land used is 180 ha, distributed between wheat (125 ha) and barley (55 ha).

Sc4-U records the highest total fuel consumption at 182,400 L, where wheat and maize require 130.2 L/ha and 108.3 L/ha, respectively. The significant fuel use in this scenario, especially for maize, points to highly intensive farming operations or larger scale cultivation requiring more fuel per hectare. This scenario also has the largest land utilization at 1,300 ha, with 500 ha for wheat and 800 ha for maize.

This simplified analysis underscores the variability in diesel fuel efficiency and total consumption across different crops and scenarios. The fuel efficiency (L/ha) offers insights into the relative energy demands of wheat, maize, and barley cultivation under varied agricultural conditions. It is evident that even though multiple farms may grow the same crop simultaneously, there can be significant variations in fuel footprints due to external factors such as weather conditions, farming practices, and the state of machinery used. Furthermore, the results certainly affirm that the farm structure has significant effect on the total fuel annual fuel consumption of each farm but does not necessarily mean that large scale farmers are less efficient when it comes to fuel usage per crop cultivated on a farm.

The fuel footprint of different farm activities can be analysed by studying which activities dominate the fuel usage across all farms as seen in Figure 6.

The graph highlights that land preparation and harvesting are the most fuel-intensive stages of field operations across all crops and

TABLE 5 Data used to study the best possible operational mode of these hydrogen systems.

Country	Utility rate (70%) kgs H2	2025–2030 Projections (€/MWh)	2030–2035 Projections (€/MWh)	2035–2040 Projections (€/MWh)
Italy	7,407	126.8	75	65
Germany	25,295	95.2	65	55
Sweden	16,354	46.5	45	40
United States	51,864	42.5	40	37.5

TABLE 6 Results of Total Annual fuel consumption for farms under different scenarios because of growing two types of cereal crops.

	Diesel wheat Litres (L/ha)	Diesel maize Litres (L/ha)	Total fuel consumed Litres/yr.
Sc1-I	1,045 (104.5)		
		1,640 (109.3)	2,685
Sc2-G	24,196 (142.2)		
		10,771 (134.6)	34,967
Sc3-S	15,875 (80.6)	(barley)	
		4,389 (79.8)	20,264
Sc4-U	80,000 (130.2)		
		102,400 (108.3)	182,400

scenarios. Similar patterns have been observed in other studies. For instance, Grisso et al. (2014) found that ploughing and harvesting can constitute more than 60% of total fuel consumption in agricultural operations. This is consistent with our findings, where land preparation, particularly, shows the highest fuel consumption in scenarios such as Sc1-I for both wheat and maize.

Planting and crop management exhibit moderate to high variability in fuel consumption across different scenarios. This suggests there are significant opportunities for improving efficiency in these stages. Studies like Francesco et al. (2011) have also highlighted the potential for fuel savings through optimized planting techniques and better crop management practices.

Post-harvest activities consistently require the least fuel, indicating efficient practices are already in place during this stage. This finding aligns with research by Flammini et al. (2022), Gustavo et al., (2013) which also reported minimal fuel use in post-harvest operations due to advancements in mechanical efficiency and streamlined processes.

Hydrogen production and refuelling station dimensioning

The capacity and daily production of hydrogen varied across countries, reflecting the scale of agricultural activities and energy requirements (Table 7).

The optimization process ensured that a single electrolyser unit would suffice for the maximum daily hydrogen demand, with storage capacities tailored to each country's needs (Table 7).

Economic analysis

The financial viability of decentralized hydrogen production on farms is critically dependent on both capital expenditures (CAPEX) and operational expenditures (OPEX). This section discusses the cost assessment across Italy, Germany, Sweden, and the United States, using the detailed assumptions and data provided in the previous section.

Capital expenditures (CAPEX)

Electrolyser costs

The initial investment in electrolysers shows significant variation across the countries, with costs ranging from €55,000 in Italy to €507,500 in the United States (refer to Table 8). This substantial difference can be attributed to local market conditions, technology costs, and the scale of hydrogen production systems required. Sweden and Germany fall in between, with costs of €106,700 and €170,000 respectively. These variations significantly impact the total CAPEX, making the USA's initial investment notably higher than other countries.

Stack replacement costs

Uniformly set at 15% of the electrolyser CAPEX, stack replacement costs ensure a consistent approach to maintenance across different regions. These costs are €8,250 in Italy, €25,500 in Germany, €16,005 in Sweden, and €76,125 in the United States. The uniform percentage ensures proportionality to the initial investment, facilitating a standard method for financial planning.

Storage tank costs

The costs for storage tanks are standardized at approximately 200 €/kg, leading to absolute costs of €4,000 in Italy, €36,000 in Germany, €24,000 in Sweden, and €80,000 in the United States. This uniformity ensures comparability in evaluating storage infrastructure across different countries.

Compressor costs

Compressor costs exhibit significant variability, with Italy incurring a relatively low cost of €6,700, while Germany faces a scaled cost of €300,000 due to larger system sizes. Sweden's costs are €218,199, whereas the USA's are €436,975.5 both of which were

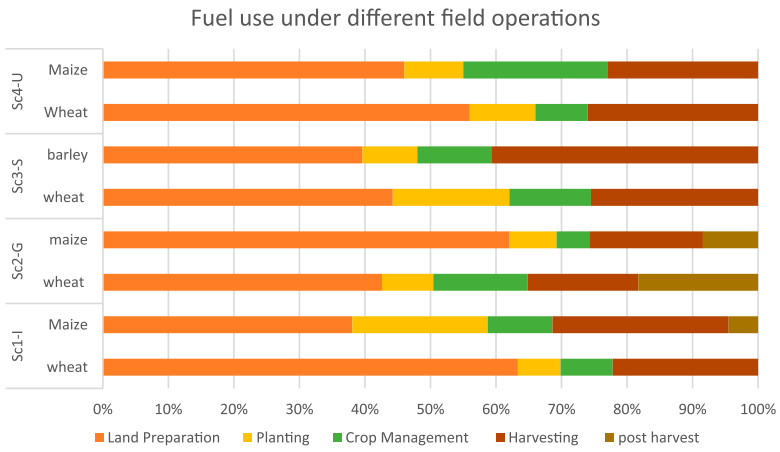

FIGURE 6
Fuel usage by different cereal crop activities as a percentage of total annual fuel consumed under different scenarios.

derived from scaling the sizes of the compressor by a factor of 0.6 from the reference hydrogen plant. The variability in costs reflects different system requirements and local manufacturing efficiencies.

Dispenser and chiller costs

Uniformly set at €170,000 for most countries, dispenser and chiller costs are significantly higher in the United States at €509,804.8. This discrepancy is due to the scaling required for larger systems in the United States, reflecting higher capacity requirements. Furthermore, the assumptions take into consideration that EU countries on aspects of product development of these technologies have higher prospects of having standard equipment costs due to economic partnerships under joint research projects with industry partners.

Installation and permitting costs

Installation and permitting costs, calculated as 15% of the capital equipment cost, vary by country: €36,592.5 in Italy, €105,225 in Germany, €80,236 in Sweden, and €538,936.5 in the United States. These costs account for local regulatory and labour conditions, impacting the total CAPEX.

The annual fixed operational costs for decentralized hydrogen production systems exhibit significant variability across Italy, Germany, Sweden, and the United States (refer to Table 9). The high costs of electrolyser maintenance and interest expenses dominate Italy's and the USA's FCOP profiles, underscoring the importance of initial investments and financing when switching to such energy systems. However, for variable operational costs are directly proportional to the capacity sizes and are dominated by the electricity costs followed by the costs of water consumed for the electrolysis process refer to the Supplementary Table SA1.

Studies such as those by Larry (2008) and Jonas and Lagnelöv (2018) emphasize the high operational costs associated with electrolyser maintenance and labour, aligning with the findings presented here. These studies also highlight the critical role of financing in hydrogen production, consistent with the significant interest costs observed in this analysis.

Additionally, the IEA (2019) report notes that high labour and maintenance costs can significantly impact the overall operational expenses of hydrogen production systems. This is particularly evident in Germany and Sweden, where salaries and overheads constitute the largest portion of FCOP. The report suggests that optimizing labour efficiency and reducing maintenance costs could improve the economic viability of these systems.

NPV and LCOH

The economic analysis of the hydrogen system was investigated based on two critical financial metrics: Net Present Value (NPV) and Levelized Cost of Hydrogen (LCOH). These metrics were evaluated under different operational scenarios to understand the economic feasibility and competitiveness of hydrogen production for machinery operations across Italy, Germany, Sweden, and the United States. The results are divided into two sets: one based on hydrogen demand for machinery operations (HDP) under assumptions that these farms produce fuel for their own needs on the farm and nothing further. However, the results of the first economic model revealed that the projects are not feasible across all scenarios refer to Table 10.

The negative NPVs across all countries indicate that, under current conditions, the hydrogen production systems are not financially viable Table 10: Results of the first economic model. The LCOH values vary significantly, with the United States achieving the lowest LCOH at 10.9 €/kg H2, reflecting its larger scale and potentially lower operational costs. Conversely, Italy has the highest LCOH at 57.4 €/kg H2, suggesting higher costs per kilogram of hydrogen produced due to smaller scale operations and higher electricity price. Thus, the LCOH where quite higher for all farms with lower volumes of production therefore confirming the trend of LCOH being directly proportional to the utility rate of the electrolyser in use due to the existence of economies of scale refer to Figure 7.

TABLE 7 Results of the Electrolyser Optimisation and Tank sizing.

Country	Electrolyser capacity (kW)	Electrolyser daily production (kg)	Max daily H2 demand (kg)	Electrolyser size (units)	Tank size (kg)
Italy	50	29	3	1	7
Germany	170	99	86	1	173
Sweden	110	64	54	1	108
United States	350	203	196	1	392

TABLE 8 Capital requirement for the hydrogen fuel system setup across different scenarios.

Equipment capital costs (CAPEX)	Italy	Germany	Sweden	United States
Electrolyser (€)	55,000	170,000	106,700	507,500.0
Stack replacement costs 15% of elec. Capex (€)	8,250	25,500	16,005	76,125.0
Storage Tank (€)	4,000	36,000	24,000	80,000.0
Compressor (€)	6,700	300,000	218,199	436,975.5
Dispenser + Chiller (€)	170,000	170,000	170,000	509,804.8
Installation and Permitting (€)	36,592.5	105,225	80,236	538,936.5
Total Initial Capital costs (€)	280,542.5	806,725.0	615,139.1	2,149,341.8

TABLE 9 Annual Fixed Costs of operations for the distinct hydrogen fuel system setups across different scenarios.

Annual fixed cost of operation (FCOP)	Italy	Germany	Sweden	United States
Electrolyser (€)	2,500	8,500	5,500	17,500.0
Storage at 5€/KG (€)	100	900	600	2000.0
Dispenser + chiller (€)	5,350	5,350	5,350	32,754.0
Compressor (€)	268	15,000	8,727.9	28,074.9
Salary and overheads	3,000	30,000	30,000	30,000
Maintenace	281	8,067	615	21,493
Interest (3%)	8,416	24,202	18,454	78,021
Fixed Cost of Operation (FCOP) (€)	19,915	92,019	69,247	209,843

The second results of the economic model explored the impact of increasing the electrolyser utilization rate to 70% (refer to Figure 8). Additionally, a sub-scenario includes the effect of offsetting extra revenue from by-products. The results revealed that Increasing the electrolyser utilization rate to 70% significantly improves the NPV and reduces the LCOH in all countries (refer to Figures 7, 8). These improvements highlight the importance of optimizing electrolyser utilization and leveraging additional revenue streams to enhance the economic feasibility of hydrogen production systems as viable option that can increase feasibility of these systems however, issue of how these products will reach the market is still under study. The United States still maintains a relatively low LCOH at 10.8 €/kg H2, with a further increment to 14.6 €/kg if the utility rate is raised to 70% while it reduces to 12.9 €/kg H2 when considering by-product revenue offsets. Germany achieves the most substantial reduction in LCOH, from 21.8 €/kg H2 to 11.6 €/kg H2, and further down to 7.5 €/kg H2 with by-product revenue refer to Figure 8. Significant reductions are seen under the scenario of Italy whereby increasing its utility rate would reduce the LCOH from 57.4 €/kg H2 to 18.7 €/kg under the best-case scenario of Italian farms.

Discussion

Most of the research on hydrogen application in farming has focused on enhancing the performance of machinery by improving efficiency. Carroquino et al. (2019) conducted a study on a self-sufficient renewable energy system that used solar energy to power irrigation in a vineyard. The excess energy produced was used to generate hydrogen for a fuel cell electric vehicle that was used on the site for workers' mobility. The authors found that this system could save up to 1,084 L of diesel by replacing it with hydrogen. However, the study did not cover the use of agricultural tillage machinery. So, this study conducted here is much more holistic taking all or most of the farm machinery activities

TABLE 10 Results of the first economic model.

	Utilisation rate (%)	Load hours (HDP)	NPV (HDP) (€)	LCOH (HDP) (€/kg)
Italy	7.6	667	−555575.0	57.4
Germany	26.9	2,355	−2415481.5	22.3
Sweden	26.0	2,280	−1521762.1	21.8
United States	61.4	5,382	−4525573.5	10.9

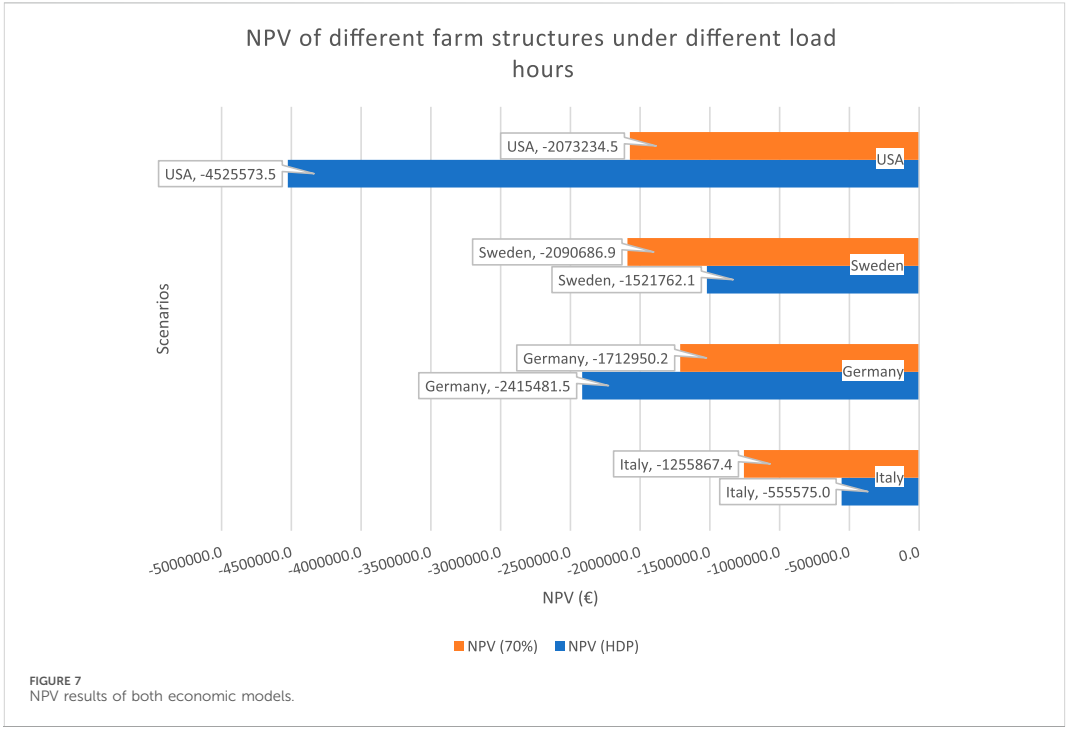

FIGURE 7
NPV results of both economic models.

that contribute to these food systems which will be impacted by the future transitions in the transport industry.

In another study, Janke et al. (2020) investigated different cases and technological scenarios to explore the future use of hydrogen by single-case farms. They proposed that four farms of 300 hectares could share investment costs for a wind-powered hydrogen refuelling unit. The authors found that sharing costs reduced the hydrogen production cost by 35% due to economies of scale and more distributed hydrogen demand. However, they only modelled the system to replace 28% of the total annual fuel use on these farms, and they used an assumed figure. None of these studies have considered the fuel consumption patterns resulting from the use of agricultural machinery on the farm. Therefore, this study takes into account the desirable positions of most agricultural stakeholders that are aiming towards decarbonisation by having hydrogen produced on the farm run the whole farm machinery.

In our case study, we have found that fuel consumption on a farm is dependent on the activities related to the crop being grown, which in turn are subject to the specific field operations required for each type of crop. The study has also revealed that, even if two farms are growing the same crop, external factors such as regulations on tillage methods, soil texture, weather, and location can significantly affect their fuel consumption patterns. Moreover, we have identified that the variations in carbon abatement tax have a significant impact on the adoption of these technologies, with Germany having the highest carbon tax cost savings, but not necessarily the highest emission reductions.

The study was also able to quantify the possible emission footprints of different farm structures in producing cereal crops. With the highest footprints belonging to highly mechanised farm structures but also these farms have the most economical potential for hydrogen production on site if renewable sources are employed for electricity production as observed in the results of the second economic model.

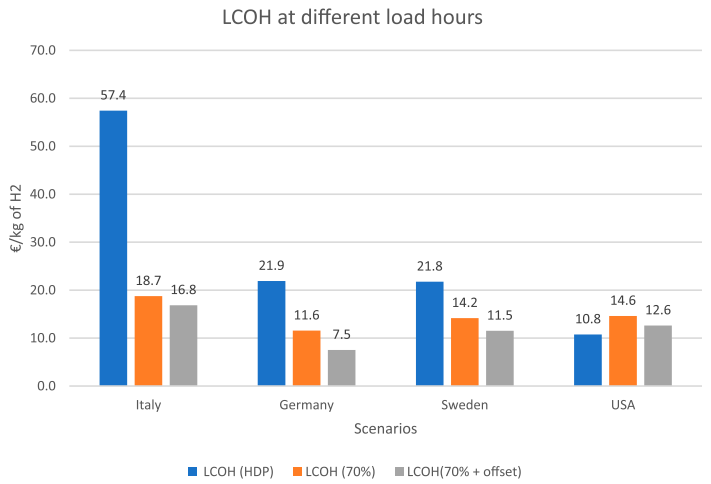

FIGURE 8
Levelized Cost of energy across both economic models under different load hours.

The study highlights that hydrogen systems for farm usage face significant challenges, primarily due to the high-cost implications of owning such systems. This includes substantial expenses for the equipment, storage, and handling of hydrogen, driven by the necessity to mitigate safety risks during operation (Proost, 2019). Despite these financial hurdles, hydrogen technologies offer a promising solution to reduce emissions from fossil fuel usage on farms, which account for approximately 15%–25% of a farm's total emissions (Flammini et al., 2022). However, this reduction is only a partial solution. A significant portion of farm emissions, particularly those from fertilizer use, remain unaddressed by hydrogen systems. Fertilizer emissions constitute the largest share of a farm's emission profile, suggesting that while hydrogen can help mitigate some environmental impacts, it does not fully resolve the issue (Larry, 2008).

Comparatively, the adoption of electric-powered tractors presents an alternative with its own set of benefits and challenges. Electric tractors offer the advantage of zero tailpipe emissions and lower operational costs due to reduced fuel and maintenance needs (Francesco et al., 2011). Moreover, they align well with the increasing availability of renewable electricity, which can further enhance their sustainability credentials (IEA, 2019). However, the current limitations of electric tractors, such as high weight to PTO ratios, limited battery life and the need for significant charging infrastructure, pose challenges for their widespread adoption, particularly on larger farms or those with high-intensity usage (Jonas and Lagnelöv, 2018). In contrast, hydrogen systems, despite their higher costs, offer quicker refuelling times and longer operational periods, which can be more suitable for extensive farm operations.

Conclusion

This study explored the application of hydrogen in cereal crop farming, with a focus on decentralized hydrogen production using electrolysers across various farm categories defined by size, structure, and crop type. Andreas et al. (2019) emphasized that reducing hydrogen production costs requires purchasing low-cost electricity, maximizing plant efficiency, and minimizing investment costs. Our study investigated the positive impact of low-cost electricity based on future price projections by the IEA,[7],[8] USEIA,[9] and CE DEFT,[10] considering scenarios at five-year intervals from 2025 to 2040.

To maximize plant efficiency, we examined increasing the utilization rate to 70%, recognizing that future renewable energy sources may not achieve corresponding load hours due to their operational limitations. Other studies, such as those by the IEA (2019), highlight the importance of strategically placing hydrogen plants in areas with high full-load hours. This is particularly crucial when these plants are connected to photovoltaic (PV) or wind parks, as it is essential for optimizing performance.

Hydrogen technology is becoming increasingly applicable in agriculture, with significant advancements in hydrogen-powered tractors, such as those developed by Deutz in Germany. However, the economic feasibility of using exclusively green hydrogen is challenging, particularly for small-scale farms. To enhance hydrogen supply chains and make them more

7 International Energy Agency - World Energy Outlook 2023: https://www.iea.org/reports/world-energy-outlook-2023.

8 International Energy Agency - World Energy Outlook 2022: https://www.iea.org/reports/world-energy-outlook-2022.

9 U.S. Energy Information Administration - Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/.

10 CE Delft - Energy and Electricity Price Scenarios: https://cedelft.eu/wp-content/uploads/sites/2/2021/04/CE_Delft_3H58_Energy_and_electricity_price_scenarios_DEF.pdf.

economically viable, it is crucial to consider other types of hydrogen, not just green hydrogen, especially for farms committed to reducing emissions (IEA, 2019).

The findings underscore the necessity for farms to have access to renewable energy sources to make hydrogen prices more affordable. The potential benefits of incorporating additional revenues from byproducts such as heat recovery and oxygen sales are limited. Although these byproducts can reduce hydrogen costs by about 2 €/kg, the associated conditioning and transportation costs are substantial. Furthermore, generating significant revenue from these byproducts is challenging due to the lack of readily available markets for large volumes of oxygen and thermal energy.

Overall, decentralized hydrogen production holds promise for reducing emissions in cereal crop farming. However, significant challenges remain, including high costs of ownership, the need for low-cost renewable energy and the economic viability of byproduct revenue streams. Further research and policy support are essential to address these challenges and enhance the feasibility of hydrogen use in agriculture. For hydrogen to be a competitive fuel for agricultural machinery, its price should be maintained below 3 €/kg. Otherwise, the high costs of storage and distribution pose significant limitations on the geographical location of production sites (Larry, 2008).

Study limitations

This study has several limitations that future research should address. Firstly, the scope was limited to cereal crops such as wheat, maize, and barley. Future studies should include cash crops like fruits, sugarcane, and cotton, as well as animal husbandry, to provide a more comprehensive analysis. Secondly, the study did not model the sizes of hydrogen components other than storage tanks and electrolysers, which were considered negligible for obtaining an overview but are essential for detailed analysis. Thirdly, the focus was on food systems in the global northern hemisphere, particularly farms in the United States and the EU. Lastly, the study did not consider the costs of tractor equipment or other agricultural machinery, focusing solely on the cost of the hydrogen fuel system as an alternative to reduce fossil fuel dependency. Future research should include these factors to provide a more detailed economic analysis of hydrogen use in agriculture.

Data availability statement

The datasets presented in this study can be found in online repositories. The names of the repository/repositories and accession number(s) can be found in the article/Supplementary Material.

Author contributions

KA: Conceptualization, Data curation, Formal Analysis, Investigation, Methodology, Project administration, Resources, Software, Supervision, Validation, Visualization, Writing–original draft, Writing–review and editing. MH: Conceptualization, Data curation, Formal Analysis, Funding acquisition, Investigation, Methodology, Project administration, Resources, Supervision, Validation, Visualization, Writing–original draft, Writing–review and editing. JS: Conceptualization, Data curation, Formal Analysis, Investigation, Methodology, Project administration, Resources, Supervision, Validation, Visualization, Writing–original draft, Writing–review and editing.

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Conflict of interest

The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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Supplementary material

The Supplementary Material for this article can be found online at: https://www.frontiersin.org/articles/10.3389/fenrg.2025.1479212/full#supplementary-material

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Review

A comparative technoeconomic and life cycle assessment of a fully battery-electric ROPAX ferry

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ABSTRACT

The maritime sector is a significant contributor to global greenhouse gas emissions. It is a hard-to-abate sector, where no easy ways out are in sight. Unlike much of road transportation, where electrification has become a widely adopted solutions, fully battery-electric propulsion has not been considered a viable option. Recent developments have, however, changed this belief. The introduction of all-electric battery-powered propulsion is not just a matter of changing power source but requires a number of changes in the ways ships are operated and, in the way, (fast) charging is enabled. This study assesses the environmental and economic performance of novel shipping concept designed around a 110 MWh lithium iron phosphate battery-electric RoPax ferry to operate on the Helsinki–Tallinn route, representing the first deployment of such a large-scale system in short-sea shipping. A life cycle assessment (LCA) with a well-to-wake boundary and a techno-economic analysis were conducted to benchmark the battery-electric vessel against conventional fossil fuels and alternative low-carbon fuels under recently introduced regulatory schemes. A well-to-wake life cycle assessment (LCA) and techno-economic analysis were conducted using a two-tier approach: Tier 1 quantifies total life-cycle greenhouse gas emissions via GWP100, while Tier 2 expands to midpoint indicators to assess environmental trade-offs beyond climate change. Results show that when powered by 100 % renewable electricity, the battery-electric ferry achieves the lowest GWP (~61,881 tCO_2-eq over 30 years), compared to ~1.69 million tCO_2-eq for marine gas oil, ~1.67 million tCO_2-eq for liquefied natural gas, ~955,342 tCO_2-eq for liquefied biogas, and ~348,446 tCO_2-eq for renewable e-methanol. However, use of the current Finnish–Estonian grid mix increases emissions more than tenfold, underscoring the importance of clean grid integration. Economically, while battery-electric propulsion entails higher capital expenditure, it yields the lowest total cost of ownership under EU ETS and FEUM pricing frameworks. These findings position battery-electric RoPax ferries as a promising pathway for decarbonising short-sea shipping with both environmental and regulatory compliance advantages.

1. Introduction

The shipping sector emitted approximately 1056 million tonnes of CO_2 in 2018, accounting for about 2.89 % of global CO_2 emissions (IMO, 2020). At the EU level, maritime transport contributes 3–4 % of total emissions, exceeding 124 million tonnes of CO_2 in 2021 (EU,[1] 2024).

To complement global IMO initiatives, the EU has implemented policies such as the"Fit[2] for 55″ package and FuelEU[3] Maritime (FEUM) and extending emission trading (EU ETS) to shipping, which aim to reduce GHG intensity in maritime transport and encourage the adoption of renewable and low-carbon fuels (IMO, 2023). These regional measures, together with global initiatives—such as the IMO's decision in

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[1] https://climate.ec.europa.eu/eu-action/transport/reducing-emissions-shipping-sector_en.
[2] https://www.lr.org/en/services/statutory-compliance/fit-for55/?creative=&keyword=fit%20for%2055&matchtype=e&network=o&device=c&utm_source=bing&utm_campaign=&utm_medium=cpc&utm_content=&utm_term=fit%20for%2055&msclkid=b58f4427d82a1d3a33792364a0248a71.
[3] https://transport.ec.europa.eu/transport-modes/maritime/decarbonising-maritime-transport-fueleu-maritime_en.

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April[4] 2025 to introduce a levy on shipping emissions—provide necessary incentives and frameworks for transitioning the shipping sector toward sustainable and climate-resilient operations.

Unlike, much of road transportation where electrification is winning terrain, maritime transportation is a hard-to-abate sector, where no clear commercially feasible pathway to meet GHG emission targets is in sight. Several decarbonization pathways have been proposed. These include scaling up the production and use of low-emission fuels such as hydrogen, LNG, ammonia, and methanol; improving vessel efficiency through advanced design and technological innovation; and enhancing operational practices like slow steaming and optimized routing (Fan et al., 2021; Korberg et al., 2021; Breuer et al., 2022; Hellström et al., 2024). A clear disadvantage of the so-called alternative fuels is their high price, today several times higher than fossil benchmarks.

In addition to various alternative fuels that are broadly discussed in decarbonising maritime transport (Hellström et al., 2024), one other interesting pathway to reduce shipping emissions onboard the ships is using electric batteries to power the vessels (Wang, 2022a; Perčić et al., 2023). When the electricity used to charge the batteries is generated from renewable energy sources, the greenhouse gas emissions associated with operating the vessel become nearly negligible (Fan et al., 2021). However, batteries have significant limitations. Batteries are mostly viable for short sea shipping and especially on dedicated point-to-point routes as battery charging infrastructure needs to be in place to make the recharging of the batteries possible between the sea crossings (Wieczorek et al., 2019). In addition, production of batteries requires specific raw materials, and greenhouse gas emissions are generated on the production phase when battery packs are manufactured (Perčić et al., 2023).

Short sea shipping routes, particularly the shortest ones in liner traffic, such as those served by RoRo/RoPax (roll-on/roll-off/passenger) ships designed to carry wheeled vehicles or trains, are well-suited for fully battery-powered operations. These vessels can be equipped with batteries that are recharged during port calls. Additionally, ships operating on other relatively short, point-to-point routes could also be considered for battery integration, enhancing their operational efficiency and environmental sustainability (Korberg et al., 2021). At the same time, ocean crossing vessels in the form of deep sea shipping would require big and expensive batteries that it seems viable to utilize alternative methods to achieve their emission reduction targets such as usage of carbon-neutral or zero-carbon fuels to power up the vessels instead of utilizing batteries to run these ships (Korberg et al., 2021; Hellström et al., 2024).

In this context, we distinguish between all-electric battery-powered vessels and hybrid vessels, still using an internal combustion engine (ICE) as the prime mover, or an all-electric fuel cell-powered vessel. The benefits of hybrid-electric RoPax-ferries is established in a number of studies (Mayanti et al., 2024; Wang et al., 2018). Recent studies suggest that even fully battery-electric ship may both economically and environmentally be a viable option in the near future (Percic et al., 2020; Korberg et al., 2021). Over the past few years, the growth in battery capacity of fully electric vessels has been rapid. The world's first (large) all-electric car ferry, MF Ampere, was commissioned in 2014 with a battery capacity of 1090 kWh, while the first RoPax (or car and passenger ferry), MS Ellen, started operation in 2019 and was equipped with a 4.3 MWh battery pack (Kolodziejski and Michalska-Pozoga, 2023). Until recently, the biggest BE vessel in operation was the Yangtze River Three Gorges 1 with an installed battery capacity of 7,5 MWh. On April 29, 2024, the Chinese container shipping company COSCO reported that its Greenwater 01, an all-electric container ship equipped with batteries exceeding a capacity of 50 MWh, performed its inaugural voyage (Lopez, 2024). Moreover, an all-electric ferry with a >40MWh battery is currently under construction at the Incat Tasmania shipyard (Incat, 2023).

This study pushes the boundaries of current research by investigating a shipping concept based on a fully battery-electric RoPax ferry sized to a 110 MWh battery pack, a capacity significantly larger than those assessed in previous studies (Perčić et al., 2020a; Korberg et al., 2021). The introduction of a battery capacity of such magnitude, however, requires rethinking the way ships and shore-side charging stations are operated. Hence, it is the electric shipping concept rather than merely the vessel that should be considered. Moreover, new EU regulations are increasingly shifting the economic feasibility from conventional fossil power sources to renewable ones, yet the effect has not been compared against the rapidly developing battery technology. Therefore, the study first outlines the new electric shipping concept and then evaluates its decarbonization potential and commercial viability through an integrated comparative techno-economic analysis and life cycle assessment (LCA) grounded in realistic operational and commercial requirements. We benchmark the technical design and duty-cycle performance of the next-generation electric shipping concept against conventional fossil fuels and alternative low-carbon options, quantifying both carbon intensity and cost implications across the energy chain under EU ETS and FEUM. By investigating the opportunities and challenges inherent in these emerging energy solutions, this research provides critical insights into the feasibility of electrification as a pathway for decarbonizing short-sea shipping, thereby contributing valuable knowledge to the broader efforts of the maritime energy transition.

To achieve the objectives of this study, the paper is structured as follows: Section 2 presents a review of relevant literature on battery technologies and marine fuels. Section 3 outlines the operational profiles, vessel parameters, and details the LCA methodology and economic analysis. The results and interpretation of the findings are presented in Section 4, followed by the discussion in the Conclusions section 5.

2. Literature review

2.1. Battery electrification in marine vessels

Battery electrification in marine vessels, particularly for short-route applications such as RoPax ferries, represents a transformative strategy for significantly reducing operational emissions and fuel consumption. As emission regulations grow increasingly stringent, maritime operators are compelled to integrate innovative technologies and alternative fuels, reshaping the dynamics of fuel production and market availability. Currently, alternative fuel adoption in shipping is predominantly led by LNG-powered vessels and those utilizing hybrid or battery propulsion systems. Globally, among the 1349 operational alternative fuel vessels, 926 rely on LNG, while 396 employ hybrid or battery propulsion (Kolodziejski and Michalska-Pozoga, 2023). A notable upward trend in the preference for hybrid and battery propulsion systems is evident, with 417 of the 1046 alternative fuel ships currently on order adopting these technologies, compared to 534 vessels opting for LNG propulsion (DNV and EMSA, 2020; Kolodziejski and Michalska-Pozoga, 2023).

Jeong et al. (2022) express concerns about the overall environmental benefits of battery-powered ships, highlighting potential issues related to lifecycle emissions and the environmental impact of battery production and disposal. Nevertheless, substantial evidence from lifecycle assessments and technical studies continues to affirm the environmental advantages of maritime electrification. Research conducted by DNV GL illustrates that vessels operating on a decarbonized electricity supply, such as that available in Norway, can achieve greenhouse gas (GWP) payback periods remarkably short. Specifically, fully electric ferries demonstrate payback periods as brief as 1.4 months, while hybrid platform supply vessels achieve comparable efficiency, with payback periods of approximately 1.5 months (Lasselle et al., 2016). These findings reinforce the technical viability of integrating battery systems into maritime operations and underscore the rapid offsetting of

[4] https://www.imo.org/en/MediaCentre/PressBriefings/pages/IMO-approves-netzero-regulations.aspx.

environmental impacts linked to battery production and installation.

Technical studies have further established the feasibility of integrating batteries into maritime propulsion systems (Thangalakshmi and Ganeshram, 2022). Detailed analyses addressing the risks of lithium-ion battery thermal runaway and explosion have led to the development of robust fire suppression measures such as direct foam injection and high-pressure water mist systems that have been validated under marine conditions (DNV and EMSA, 2020). Additionally, research on the integration of shipboard microgrids has highlighted the potential of hybrid energy storage systems (HESS) to manage dynamic load fluctuations effectively while ensuring power quality (Mutarraf et al., 2018). Studies examining the installation and operational optimization of battery energy storage onboard vessels have identified digital control strategies and predictive battery management systems as critical enablers for maximizing efficiency and prolonging battery life (Kolodziejski and Michalska-Pozoga, 2023).

Economic assessments provide compelling evidence for the long-term cost benefits of battery electrification. Despite high initial capital costs and infrastructure investments, multiple studies report fuel savings in the range of 15–30 % and payback periods often under five years (Perčić et al., 2023). In applications such as RoPax ferries and even smaller vessels like all-electric fishing boats, reduced maintenance requirements and simplified drivetrain configurations further contribute to lower overall life cycle costs (Ben, 2020; Wang, 2022b; Guven and Ozgur Kayalica, 2023; Kolodziejski and Michalska-Pozoga, 2023). The case study of all-electric fishing vessels, for example, demonstrated that among various lithium-ion chemistries, Lithium Iron Phosphate (LFP) batteries offer a balanced profile in terms of environmental impact, safety, and cost-effectiveness.

Jeong et al. (2022) highlighted that the lifecycle environmental benefits of battery-powered ships are significantly influenced by the electricity mix used for charging. They argue that emissions could merely shift from onboard operations to the electricity generation phase (Jeong et al., 2022). However, subsequent studies indicate that when battery systems are integrated with renewable or decarbonized electricity grids, significant net environmental benefits can be achieved. For instance, research investigating alternative marine fuels for superyachts demonstrated that hydrogen produced using wind energy can result in greenhouse gas emission reductions exceeding 90 % compared to Marine Gas Oil (MGO) (Mutarraf et al., 2018; Vicenzutti and Sulligoi, 2021; Wang, 2022c). These findings suggest that as renewable energy increasingly dominates global electricity production, the concerns related to shifted emissions are likely to diminish progressively.

Furthermore, advances in battery technology continue to address existing limitations. Innovations in battery chemistries—such as improvements in NMC and the adoption of solid-state batteries are expected to enhance energy density, thermal stability, and overall safety (Ben, 2020; Chen et al., 2020; Porzio and Scown, 2021; Kolodziejski and Michalska-Pozoga, 2023). The ongoing development of sophisticated battery management systems that integrate machine learning and predictive analytics is anticipated to further optimize charge–discharge cycles and reduce degradation, thereby extending battery life and improving operational reliability (Chen et al., 2020; Karkosiński et al., 2021).

2.2. Existing life cycle assessment (LCA) evaluating alternative marine fuels

The study by Gilbert et al. (2018) on the full life-cycle air emissions of alternative shipping fuels underscored the necessity of alternative fuels to meet both current and future environmental regulations. Their LCA included LNG, methanol, liquid hydrogen (LH2), biodiesel, straight vegetable oil (SVO), and bio-LNG. The research emphasized that while alternative fuels could potentially reduce emissions, significant barriers remain, particularly upstream in their life cycles, which often involve high emissions during production and refining stages (Gilbert et al., 2018).

A comparative LCA conducted by Chatzinikolaou and Ventikos (2015) examined the environmental impacts of different marine fuels. They concluded that LNG and methanol have lower NOx and SOx emissions compared to conventional fuels, aligning with the findings of Brynolf et al. (2014). However, the methane slip associated with LNG engines remains a significant challenge, potentially offsetting the GHG benefits Methane slip refers to an "event" during of which some unburnt methane escapes from the combustion process into the atmosphere (Kuittinen et al., 2024). Furthermore, the study by Avadí et al. (2018) highlighted the importance of considering local environmental impacts in LCAs. For instance, while using methanol, local environmental impacts, such as potential toxicity from methanol spills, must also be considered. Methanol biodegrades quickly but it is toxic at high concentrations, requiring careful management (Avadí et al., 2018).

The technological feasibility of using alternative fuels is another critical aspect to consider. Korberg et al. (2021) discussed the technical challenges of utilizing advanced fuels like hydrogen for maritime propulsion, particularly the need for specialized infrastructure, enhanced safety measures, and engine modifications. Harahap et al. (2023) further emphasized that infrastructure challenges create ripple effects that extend to policy adoption, as increased uncertainty and risks in energy markets act as significant barriers to the wider adoption of these fuels. These findings are consistent with studies on the Croatian short-sea shipping sector, where Life Cycle Cost Analyses (LCCA) also highlighted the importance of evaluating the economic and technical feasibility of different fuel options (Burel et al., 2013; Perčić et al., 2020a).

Similarly, Perčić et al. (2020) conducted a Life-Cycle Cost Assessment (LCCA) for alternative marine fuels in short-sea shipping in Croatia. They found that electricity-powered ships, given Croatia's electricity mix of 46 % renewable sources, offered the most environmentally and economically viable option, capable of achieving a 50 % reduction in greenhouse gas (GHG) emissions (Perčić et al., 2020).

The regulatory landscape is also a crucial factor. The European Union's stringent emission regulations, as discussed in the report on decarbonizing maritime transport from the EU perspective, drive the adoption of cleaner fuels and technologies (European Parliament, 2020). This regulatory pressure has led to increased interest in alternative fuels that can comply with the International Maritime Organization's (IMO) regulations on sulfur oxides (SOx), nitrogen oxides (NOx), and particulate matter (PM) emissions (European Parliament, 2020).

3. Methods and materials

3.1. Operational route

As a case route the study considered Helsinki–Tallinn route between Finland and Estonia. It stretches roughly 48 nautical miles (88.9 km) and is characterized by frequent daily departures (Fig. 1). The operational dimensions of the vessel under study are designed to make six crossings per day, each crossing lasting approximately 2 h 15 min, thus resulting in over 3.15 million nautical miles travelled throughout a typical 30-year operational lifetime. These operations highlight both the high energy demand profiles of the current RoPax services and the importance of optimizing environmental performance of these systems.

3.2. Vessel parameter selection

In this study, five RoPax propulsion technologies were analysed, comprising four internal combustion engine (ICE) powertrain configurations and one fully battery-electric ferry. To ensure a consistent and realistic basis for comparison, all technologies were evaluated under an identical operational profile, and key parameters were established for the analysis (see Fig. 2). First, to accurately compare different energy technologies, all vessel profiles were required to maintain the same per-trip energy demand of 35 MWh (shaft power) per leg. Second,



Fig. 1. Geographical and Operational parameters of the vessel. Helsinki – Tallin Route.

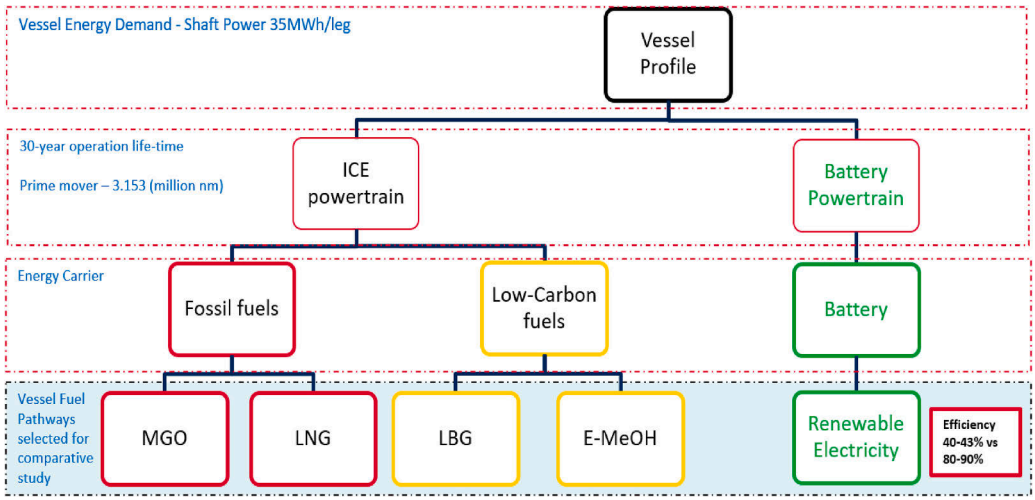

Fig. 2. Constrains of vessel parameters.

recognizing that prime mover technologies vary in configuration, the study applied constraints to assess each technology's carbon footprint over a 30-year lifetime. This corresponded to a total operational distance of 3.15 million nautical miles for both battery- and ICE-powered vessels.

Third, the study considered scenarios reflecting a plausible industry transition. The baseline involved no transition at all, relying on fossil fuels such as Marine Gas Oil (MGO), and Liquefied Natural Gas (LNG). A partial transition scenario involved low-carbon fuels like LBG (Liquefied

Biogas) and e-methanol. Finally, a fully battery-powered vessel running on charged electricity represented the most ambitious transition pathway.

3.3. Energy consumption profile

3.3.1. Conventional vessel (ICE powertrain)

We adopted the Tallink Megastar's fuel consumption as a baseline to model the fuel profiles for the selected pathways of a new electric vessel of similar size on the same route. The data was collected from EU MRV (EU MRV, 2025). This approach of using an existing vessel as a reference for scenario development follows a data-driven methodology, as seen in similar LCA-based research on marine transport (Bengtsson et al., 2011; Perčić et al., 2020; Sun et al., 2020; Wang et al., 2022b). Specifically, we compared the two vessels under the assumption that fuel consumption is directly proportional to power output. Using the following ratio, we can compute for the fuel consumption for selected vessel:

$$fC_2 = fC_1 * \left(\frac{P_2}{P_1}\right) \quad \text{Equation 1}$$

where:

FC_2 = Fuel consumption of the vessel selected for comparative study (ICE)

FC_1 = Fuel consumption of the reference vessel (Megastar)

P_2 = Shaft power of the vessel understudy.

P_1 = Shaft power of reference vessel (Megastar)

The operational profile of the Megastar closely mirrored the design considerations of the electric vessel under development for the same route, although the Megastar showed higher per-leg energy consumption due to its greater shaft power (i.e 45 MW). By grounding our analysis in real-world operational data, we ensured that our comparisons among alternative fuel pathways would accurately reflect the practical constraints and performance characteristics of this short-sea route. Using Equation (1) as a reference, we computed for both the annual and lifetime fuel consumption for ICE vessels operating under different fuel profiles (see Table 3). Consequently, when calculating fuel consumption for low-carbon fuels such as LBG, we assumed it to be equivalent to the vessel's consumption rates for LNG (see Table 4).

3.3.2. Fully battery powered electric RoPax vessel

This section details the methodology used to model the fully battery-powered electric RoPax vessel configuration within this comparative study (see Table 1). The design and operational parameters for this vessel were based on data provided by a shipyard participating in the feasibility consortium. Due to the proprietary and sensitive nature of some specific design elements, certain detailed data are restricted from publication. However, the critical parameters influencing the energy consumption and cost analysis are presented and summarized in Table 2.

For the battery-powered vessel, it was assumed that the onboard battery capacity must be sufficient to power the vessel for its full daily operations cycle. Accordingly, the required battery capacity (BC) was calculated using the following formula:

$$BC = 1.23 * EC * (6 * L) \quad \text{Equation 2}$$

where.

- BC is the required Battery Capacity (MWh)
- EC is the energy consumption per nautical mile (kWh/nm) and
- L is the length of one-way trip (nm).

The battery capacity is increased by a factor of 1.23 to account for maintaining the battery's State of Charge (SOC) within a defined operational window (range minimum 40 %, maximum 80 %), as well as to incorporate safety margins and compensate for battery degradation over time. This approach is consistent with methods employed in prior maritime electrification studies(Gilbert et al., 2018a; Perčić et al., 2020;

Table 1
Fuel consumption profiles of different fuel pathways for conventional vessel.

Conventional Vessel	2 shafts	
Power class	35 MW	
speed	27knots	
Prime mover	ICE	
Fuel	Tonnes of fuel/yr	Tonnes of fuel (30yr LFT)
MGO	14,583.33	437,500.00
LNG profile		
Pilot fuel (MGO)	230.26	6907.89
LNG (main fuel)	12,280.70	368,421.05
Total LNG + MGO	12,510.96	375,328.95
Methanol Profile		
Pilot fuel (MGO)	1535.09	46,052.63
Methanol (main fuel)	27,631.58	828,947.37
Total fuel Methanol + MGO	29,166.67	875,000.00

Table 2
Fully battery electric ROPAX Vessel.

Operational Profile of Battery ship	
Prime mover	Battery Pack
Energy Carrier	Renewable electricity
Battery capacity (MW)	110 MWh ship battery, ship (2 X 85 MWh onshore batteries)
Lifetime Energy Consumption 30yrs (GWh)	2299.50
Energy demand per crossing (MWh/leg)	35 (shaft power)
What is the minimal charge of the battery in operations (%age)	40 %
What is the maximum charge of the battery in operations (Percentage)	80 %
Battery pack lifetime	10 years
Battery type	Lithium ferro-phosphate (LFP)

Table 3
Material Input data for manufacturing of ICE prime mover platforms (Source: Engine manufacturer).

Vessel Type	MGO Ship	LNG Ship	Methanol Ship
Main engine type	8-cylinder 46F-C	8-cylinder 46DF	8-cylinder 46F
Number of units (kW)	5 x 10000	5 x 9160	5 x 10000
Engine material	Mass (kg)	Mass (kg)	Mass (kg)
Cast iron	90600	94000	90600
Steel	35200	36800	36200
Aluminium	2000	2000	2000
Oil and grease	30	30	30
Plastic	30	30	30
Rubber	50	50	50
Paint	100	100	100

Table 4
Module material Inventory per kWh (source: Guven and Ozgur Kayalica, 2023).

Component	LFP
Cathode active material [g/kWh]	2031.28
Graphite [g/kWh]	956.61
Carbon black [g/kWh]	42.32
PVDF [g/kWh]	61.84
Aluminium [g/kWh]	481.83
Copper [g/kWh]	519.65
LiPF6 [g/kWh]	3.75
EC [g/kWh]	297.29
DMC [g/kWh]	240.98
PP [g/kWh]	36.61
PE [g/kWh]	25.33
PET [g/kWh]	4.9
BMS [g/kWh]	11.81
Total [kg/kWh]	4.71

Guven and Ozgur Kayalica, 2023).

Based on this calculation, the vessel requires an onboard battery pack capacity of 110 MWh. The vessel is modelled with a diesel-electric shaft propulsion configuration, with the prime mover being a fully electric battery system rather than a conventional internal combustion engine (ICE).

Lithium-ion (Li-ion) batteries were selected as the baseline technology, given their superior performance characteristics compared to older technologies such as lead-acid and nickel-metal hydride batteries. Advantages include higher energy density, better durability, lower self-discharge rates, improved tolerance to high temperatures, and reduced maintenance needs (Ramkumar et al., 2022; Perčić et al., 2022). Their higher nominal voltage (typically 3.7 V) and energy density make them particularly suitable for heavy-duty maritime propulsion.

Among Li-ion chemistries, Lithium Ferro-Phosphate (LFP) was specifically selected. LFP batteries offer superior thermal stability, lower fire risk, and longer cycle life compared to nickel-rich chemistries like NCA and NMC 811 (Guven and Ozgur Kayalica, 2023; Perčić et al., 2022, 2023). Furthermore, LFP manufacturing results in 0.95 %–1.35 % lower CO_2 emissions and reduced freshwater and energy consumption, aligning with the safety, durability, and sustainability objectives critical to the RoPAX ferry's operational profile.

Due to the substantial size and energy density of the battery pack, a Battery Management System (BMS) is considered an essential part of the design. The BMS serves as the primary electronic control unit, monitoring key parameters such as State of Charge (SOC), State of Health (SOH), and battery temperature. It ensures balanced charging/discharging, activates thermal management processes during overheating, and protects battery modules from degradation, thus enhancing operational safety and extending system lifespan (Ramkumar et al., 2022).

The study assumes a battery pack lifetime of 10 years, necessitating two battery replacements over the vessel's 30-year operational period. Thus, a total of three battery packs are accounted for in the life cycle modelling.

Consistent with the defined system boundaries (Section 3.4.1), several elements were excluded from the scope of this analysis.

- Onshore battery storage systems (2 × 85 MWh) located at the Helsinki and Tallinn ports were excluded, as these are considered part of the broader port infrastructure. In addition to supplying vessel charging, such systems can provide ancillary services including peak shaving to reduce demand on the local grid, frequency regulation to support system balancing, and reactive power support to maintain voltage stability. These functions not only strengthen grid reliability but also reduce the need for costly grid reinforcement, while creating additional revenue opportunities for port operators. Consequently, they improve both the scalability and the long-term economic viability of port electrification, even though they are outside the scope of the vessel-focused LCA.
- The construction phase of the vessel was not included, based on the assumption that the weight differences between the battery-electric and conventional ICE vessel types are negligible. While the battery pack adds significant mass, this is largely offset by the removal of heavy internal combustion engines, fuel tanks, and auxiliary machinery, enabling structural optimization. As a result, the battery-electric vessel achieves comparable overall displacement to a conventional design by reducing structural steel weight to accommodate the battery pack without increasing total tonnage (Blasig, 2024).
- End-of-life stages for both the vessel and batteries were omitted due to uncertainties regarding future decommissioning practices and potential vessel transfers between operational regions.

Key design and operational parameters for the fully battery-electric RoPAX vessel, including its prime mover configuration, energy carrier, energy demand, SOC limits, battery lifetime, and selected battery type, are summarized in Table 2 below.

3.4. Life cycle assessment framework

To evaluate the climate and environmental performance of these vessel profiles, a two-stage assessment framework was applied. This framework aligns with the Life Cycle Assessment (LCA) methodology described by Wang, 2022a,c, which divides the evaluation into four core stages: Goal and Scope Definition, Inventory Analysis (LCI), Impact Assessment (LCIA), and Interpretation.

The Inventory Analysis (LCI) stage involves a comprehensive mapping of the entire fuel production and vessel operation pathway. This includes raw material extraction, processing, manufacturing, transportation, distribution, and bunkering operations. Operational parameters such as lifetime fuel consumption, engine construction, battery manufacturing, and electricity generation for battery-electric propulsion are also considered. Toc capture varying levels of analysis, two complementary assessment tier were employed.

Tier-1 – Screening Carbon-Footprint Analysis: This simplified, literature-based approach estimates carbon emissions using secondary emission factors from existing regulations and publications (refer to Tables 5 and 6). It provides fast and transparent CO_2-equivalent (CO_2-eq) results for well-to-wake (WTW) emissions by combining well-to-tank (WTT) and tank-to-wake (TTW) factors. Tier-1 does not model all upstream processes of capital goods or non-CO_2 midpoint categories, making it suitable for fast screening and initial comparisons.

Tier-2 – Attributional LCA in SimaPro (Multi-Impact): This is a comprehensive inventory-based assessment that is developed using the SimaPro software and ecoinvent background datasets. It models both the fuel supply chains (WTT) and the manufacturing of capital goods, including main engines, foreground unit processes for fuel production, and batteries. Environmental impacts are quantified using the ReCiPe 2016 Midpoint (H) method, with Global Warming Potential over 100 years (GWP100) highlighted to ensure comparability with Tier-1.

The third stage, Impact Assessment (LCIA), evaluates the potential environmental impacts associated with both upstream, well-to-tank, (WTT) and downstream, tank-to-wake, (TTW) processes. This assessment primarily focuses on the Global Warming Potential (GWP) as the key metric, while also considering other relevant environmental impacts. Emission factors for each fuel type are applied in conjunction with their respective calorific values and vessel-specific consumption data, allowing for a nuanced evaluation of each fuel pathway.

The fourth and final stage, Interpretation, involves synthesizing the results from both the inventory analysis and impact assessment. This synthesis facilitates the drawing of conclusions regarding the relative environmental performance of each vessel fuel profile and provides actionable feedback and recommendations for maritime decarbonization strategies, particularly in high-frequency operational corridors such as the Helsinki–Tallinn route.

3.4.1. System boundary and functional unit setting

The functional unit (FU) of this study is defined as the carbon footprint of operating a RoPax vessel over a 30-year lifetime on the Helsinki–Tallinn route. By adopting this long-term perspective, the study

Table 5
WTT emission factors of different fuels.

	LCV	WTT	
Fuel	MJ/g of fuel	gCO2 eq/MJ	Sources
MDO/MGO	0.0427	14.4	Regulation (EU) 2023/1805
LNG	0.0491	18.5	Regulation (EU) 2023/1805
Synthetic MeOH	0.0199	10	Carlo and Mark (2022)
LBG	0.0493	21.3	Spoof-Tuomi and Niemi (2020)

Table 6
TTW emission factors of different fuels.

	TTW				
Fuel	CO_2	N_20	CH4		sources
MDO/ MGO	3.206	0.00018	0.00005	g pollutants/ g fuel	Regulation (EU) 2023/ 1805
LNG	2.75	0.00011	Computed as % of mass fuel CH4 slip	g pollutants/ g fuel	Regulation (EU) 2023/ 1805
Synthetic MeOH	0	0	0	g pollutants/ g fuel	Carlo and Mark (2022)
LBG	1	0.0022	0.41+ slip (Computed as % of mass fuel consumed)	g pollutants/ MJ	Spoof-Tuomi and Niemi (2020)

provides valuable insights into sustainability, enabling decision-makers and stakeholders to optimize maritime transport operations and minimize environmental impact (Cucinotta et al., 2021).

In line with established LCA principles and the ISO 14040 series standards, this research adopts an extensive Well-to-Wake (WTW) system boundary to capture the full life cycle of each fuel pathway (Klöpffer, 2014; Klöpffer and Grahl, 2014; Wang et al., 2018). Within this framework, the life-cycle emissions are categorized into three main phases: Manufacturing (M), Well-to-Tank (WTT), and Tank-to-Wake (TTW) (refer to Fig. 3).

The Manufacturing (M) emissions account for the environmental impact of producing key vessel components, including the engine for combustion-based systems and the battery for electric propulsion. The Well-to-Tank (WTT) emissions cover the entire fuel cycle, encompassing raw material extraction, fuel production, processing, and transportation to the vessel (Lee et al., 2024). The Tank-to-Wake (TTW) emissions represent the direct operational emissions released during vessel operation, including fuel combustion and methane slip (CH_4) in ICE-based propulsion systems. In the case of battery-electric vessels, emissions are determined by the carbon intensity of the electricity used for charging during operations (Brynolf, 2014; Seithe et al., 2020; Wang et al., Wang, 2022c; Lee et al., 2024). This implies that the total life-cycle emissions E_i (kg/tonnes) of a given pollutant i are obtained by summing the emissions from all three LCA phases:

$$E_i = E_m + E_{WTT} + E_{TTW} \quad \text{Equation 3}$$

By integrating the manufacturing (M), WTT, and TTW stages, this study provides a holistic assessment of the vessel's environmental impact over its operational lifetime. This comprehensive methodology follows the ISO 14040 framework encompassing goal and scope definition, inventory analysis, impact assessment, and interpretation to ensure that all relevant environmental impacts are fully captured and evaluated across the vessel's entire life cycle (European Commission. Joint Research Centre. Institute for Environment and Sustainability, 2010; Charles H, 2014; Klöpffer, 2014; Gilbert et al., 2018; Guven and Ozgur Kayalica, 2023; Perčić et al., 2023).

3.4.2. Life cycle inventory

3.4.2.1. Inventory for Tier-1 emissions: simplified carbon footprint analysis

3.4.2.1.1. Construction of engines and battery manufacturing (prime mover). Our study considered five ROPAX operational profiles, four of which were internal combustion engine (ICE) powertrain topologies, alongside one fully battery-powered RoPax ferry. The system boundary encompassed the manufacturing stages of the primary propulsion components namely, the engines and battery systems for each vessel.

For the ICE profiles, material input data related to engine manufacturing was provided directly by the engine manufacturer participating in the feasibility consortium (see Table 3). For the battery-electric alternative, material inventory were sourced from Guven and Ozgur Kayalica (2023), specifically focusing on lithium iron phosphate (LFP) battery chemistry (see Table 3).

The emissions associated with the manufacturing stages of both internal combustion engine (ICE) platforms and battery systems are calculated using a mass allocation approach. This method quantifies manufacturing-stage emissions in CO_2-equivalent terms by multiplying the mass of each material *j* by the aggregated global warming potential for 100 years (GWP) of its respective CO_2, CH_4, and N_2O emissions, and then summing these products across all materials, as expressed in Equation (4). Material-specific emission factors were sourced from Guven and Kayalica (2023) and are derived from the GREET® life-cycle assessment model (see Appendix). All computations were performed in Microsoft Excel.

$$E_M = \sum_{j=1}^{n} \left(m_j * \left[EF_{CO2,j} * 1 + EF_{CH4,j} * 28 + EF_{N2O,j} * 265\right]\right) \quad \text{Equation 4}$$

where.

- m_j is the mass of material j
- $EF_{CO2,j}$, $EF_{CH4,j}$, and $EF_{N2O,j}$ are the emission factors (in kg pollutant per kg material) for each respective gas during production of material j.

3.4.2.1.2. Emissions due to upstream processes - WTT. A typical methodology for quantifying well-to-tank (WTT) emissions of marine fuels involves multiplying the mass of each consumed fuel by its lower calorific value (LCV) and the corresponding WTT emission factor and then summing these products across all fuel types. The calculation can be investigated using the equation below:

$$E_{WTT} = \sum_{f=1}^{n} \left(m_f * LCV_f * EF_{WTT,f}\right) \quad \text{Equation 5}$$

where.

- m_f is the mass of the *f-th* fuel consumed (in tonnes)
- LCV_f is the lower calorific value of the *f-th* fuel (in MJ/g), and
- $EF_{WTT,f}$ is the emission factor of the *f-th* fuel (in gCO_2-eq/MJ)

3.4.2.1.3. Operational emissions -TTW. To quantify tank-to-wake (TTW) emissions in tonnes of CO_2-equivalent (tCO_2-eq), the emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are first computed separately, then combined using their respective 100-year global warming potentials (GWP_{100}). This procedure provides a standardized metric for comparing the climate impacts of different emission sources. The calculation is shown Equation (6):

$$E_{TTW} = \sum_{f=1}^{n} \left(m_f * \left[EF_{CO2,f} * 1 + EF_{CH4,f} * 28 + EF_{N2O,f} * 265\right]\right) \quad \text{Equation 6}$$

where.

- m_f is the mass of the *f-th* fuel consumed (in tonnes)
- $EF_{CO2,j}$, $EF_{CH4,j}$, and $EF_{N2O,j}$ are the emission factors (in kg pollutant per kg fuel) for each respective gas during combustion of fuel *f*.

3.4.2.2. Inventory for Tier-2 emissions- Multi-Impact LCA

3.4.2.2.1. Upstream (WTT) — energy chains and capital goods (prime movers). The WTT block includes (i) extraction/collection, processing/upgrading, transport and bunkering for LNG, MGO, e-MeOH, LBG, modelled on an mass and energy basis (g-eq MJ^{-1}), and (ii) the manufacturing footprint of the prime movers (main engines and after-treatment), treated as capital goods and amortised to the FU (emissions per unit of work done).

Prime-mover manufacturing: bill-of-materials from the OEM (cast iron, steel, aluminium, elastomers, coatings, auxiliaries) is mapped to

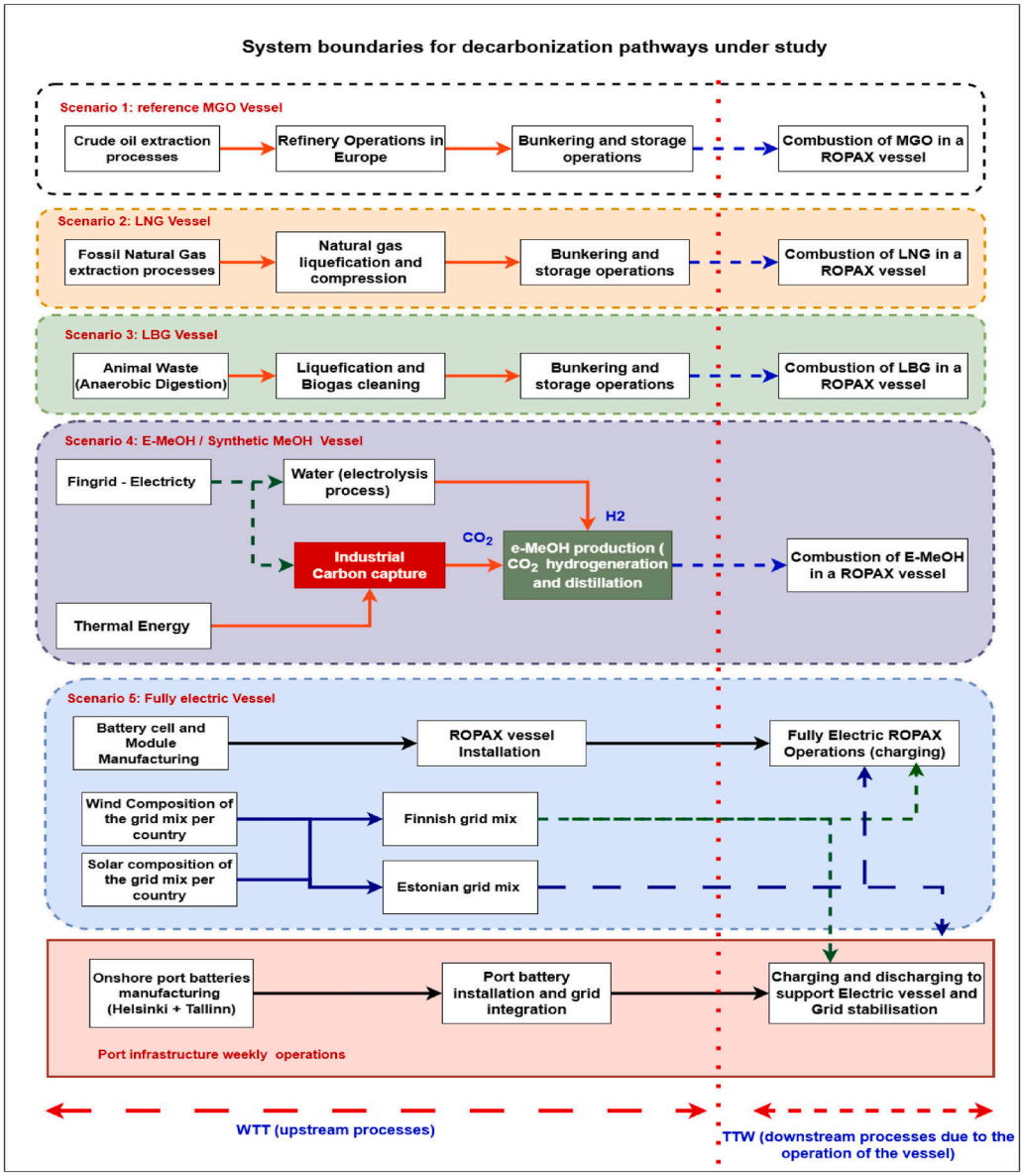

Fig. 3. System boundary for inventory data collection and analysis.

background unit processes in simapro software. Upstream processes of manufacturing engines are assumed to be in Sweden. whereas the battery is modelled to be manufactured in China and shipped to Finland for assembly. The emission inventory data for batteries and engine manufacturing used under this stage are from ecoinvent 3&2 data-sets embedded in the software. Emissions are converted to ReCiPe Midpoint categories and allocated over the vessel's total lifetime to analyse emissions sources (and across parallel units where applicable). This is consistent with attributional LCA practice for including capital goods when they are germane to the comparison of propulsion options (Bengtsson et al., 2011; Brynolf et al., 2014).

e-MeOH process blocks (power-to-liquid): We explicitly model electrolysis H_2, CO_2 capture, methanol synthesis, and conditioning-

- Hydrogen via electrolysis. The cradle-to-gate inventory for electro-methanol (e-MeOH) in this study is taken from Peppas et al. (2024), which provides a transparent LCA for synthetic methanol alongside alternative fuels, including the underlying electrolysis-H_2, CO_2 supply, and methanol synthesis building blocks and data ranges suitable for maritime attributional modelling (refer to tables C & D in appendix). We adopt their parameterisation as the reference WTT dataset and apply our route-bounded energy demand to derive well-to-wake results (Huang et al., 2022). Scenario variants (electricity mix, CO_2 source, and process integration) are implemented as sensitivity cases around that reference. Base case assumes alkaline electrolysis; literature indicates 56–57 kWh kg^{-1} H_2 electricity plus ~0.9 kWh kg^{-1} for compression to ~35 bar; ~11 kg water per kg H_2 (range for alkaline ~54–84 kWh kg^{-1})(Malmgren et al., 2021).
- CO_2 capture options. For the CO_2 supply to synthesis we evaluate three pathways: direct air capture (DAC) using moisture-swing solid sorbent, flue-gas capture (industrial point-source), and biogenic CO_2 (e.g., from biomass conversion) (refer to tables E &D in appendix). The DAC electricity demand is parameterised at ≈ 1.1 MJ kg^{-1} CO_2 (≈0.31 kWh kg^{-1}), consistent with the HyMethShip methodological annex for moisture-swing DAC; this figure anchors our base DAC case, while higher-energy variants are explored in sensitivity to reflect technology spread reported in the literature (Malmgren et al., 2021).

LBG process blocks. WTT includes anaerobic digestion (feedstock preparation, digester operation), upgrading to biomethane, and liquefaction. In RED-II-style accounting, digestate credits and off-gas combustion can yield very low—or even negative—net WTT intensities for some waste pathways; liquefaction energy ~0.7 kWh kg^{-1} LBG is reported under renewable electricity (Dong et al., 2024; Spoof-Tuomi and Niemi, 2020).

LNG pathway (natural gas → liquefaction → distribution); Gas production/processing, pipeline transport, liquefaction, shipping, terminal handling. The study assumes the source of LNG is to be Netherlands thus means LNG is transported to bunkering station in Helsinki ports to facilitale operations. Liquefaction energy is a major contributor; typical ranges ≈0.2–0.4 kg CO_2 per kg LNG depending on technology and power source (Skone et al., 2016; Selma et al., 2023). Upstream CH_4 leakage is scenario-tested (regional gas supply variability). WTT is provided as g-eq MJ^{-1} LHV.

MGO/MDO pathway (refining and distribution): Crude extraction, transport, refining (atmospheric & vacuum distillation; hydrotreating), distribution. The study considered VLSF/MGO from a refinery in Netherlands which is the transported by sea to Helsinki for bunkering operations when modelling the upstream processes of this fuel pathway.

Electricity grid modelling: Electricity used in upstream processes—particularly for hydrogen electrolysis, CO_2 capture, fuel synthesis, and battery charging—is modelled using country-specific grid mixes to reflect regional energy system characteristics. For this study, the 2025 grid compositions of Finland and Estonia were analysed using data from Low Carbon Power org.[5] Finland's grid is dominated by low-carbon sources, with nuclear (35 %), wind (25 %), hydro (14 %), and bioenergy (11 %) comprising the majority of generation, while fossil fuels such as coal and oil are absent. Estonia's grid, by contrast, includes significant shares of oil (22.2 %), coal (7 %), and imported electricity (24.1 %), alongside renewables such as wind (21.1 %) and solar PV (16.5 %). These differences are critical in modelling the upstream emissions of electricity-intensive processes, particularly for battery-electric vessels and synthetic fuel production. The carbon intensity of electricity directly influences the well-to-tank (WTT) emissions of electrolysis-based hydrogen and e-fuels, as well as the tank-to-wake (TTW) emissions of electric propulsion systems. Accordingly, the study applies a weighted grid mix for hybrid scenarios (e.g., 50 % Fingrid + 50 % Estonian grid) and tests sensitivity to grid composition to capture the variability in upstream emissions and its impact on overall life-cycle performance (Brynolf et al., 2014; Malmgren et al., 2021; Peppas et al., 2024).

3.4.2.2.2. TTW emission inventory for selected marine fuels. The Tank-to-Wake (TTW) combustion emission factors for Marine Gas Oil (MGO/MDO), Liquefied Natural Gas (LNG), Liquefied Biogas (LBG), and synthetic methanol (e-MeOH) were compiled from recent peer-reviewed studies to support attributional life cycle modeling in SimaPro (refer to Table 7). Emission data for MGO/MDO were sourced from Gilbert et al. (2018), who provided standardized combustion profiles for conventional marine fuels. LNG emissions were extracted from Kuittinen et al. (2024), based on real-world measurements from a 4-stroke low-pressure dual-fuel engine operating at 80 % load without selective catalytic reduction (SCR), including methane slip and black carbon. LBG data were modelled by Dong et al. (2024) using RED-II accounting for biogas derived from municipal organic waste. Synthetic methanol emissions were obtained from Kanchiralla et al. (2023), who assessed both internal combustion engine (ICE) and solid oxide fuel cell (SOFC) configurations under prospective life cycle scenarios.

3.5. Economic impact analysis

3.5.1. Economic analyses

The cash flows of using different types of energy sources are calculated and net present costs of the ships are investigated and compared to one another. The goal of the economic analyses is to assess the economic potential of all-electric battery-powered propulsion in RoPax shipping. In this study, an all-electric battery-powered vessel is compared to ships with conventional powertrains served by internal combustion engines. The battery-powered RoPax ship is compared to the same vessels and energy sources as in the LCA part of the study. The economic potential of these ships is calculated by taking both costs and potential revenue streams into account.

For costs, both capital expenditure (CAPEX) and operational expenses (OPEX) of the vessels are calculated first, after of which possible environment related cash flows such as FEUM revenues from pooling of vessels are subtracted from the total costs, and EU ETS costs and FEUM pooling expenditure are added up to these total costs.

Table 7
Fuel combustion stage emission factors: sources- MGO/MDO from (Gilbert et al., 2018); LNG from (Kuittinen et al., 2024); LBG from (Dong et al., 2024); e-MeOH (Kanchiralla et al., 2023).

Pollutant	Unit	MGO/MDO	LNG	LBG	e-MeOH
CO_2	g/kWh	524	460	275.5	520
CH_4 (Methane slip)	g/kWh	0.01	2.8	0.016	~0
NO_x	g/kWh	14.8	3.4	1.34	2.6 (ICE)/ ~0 (SOFC)
CO	g/kWh	0.026	5	2.59	1.7 (ICE)/ ~0 (SOFC)
PM_{10}	g/kWh	0.16	0.0055	0.011	0.093 (ICE)/~0 (SOFC)
SO_x	g/kWh	0.32	~0	0	0
N_2O	g/kWh	0.018	~0	0.01	~0
NMVOC	g/kWh	2.4		1.59	
BC	mg/kWh	7.3–39	0.4	0.19	
Formaldehyde (HCHO)	mg/kWh	~72	500		0.49
PN_{av} >23 nm	particles/kWh		0.85×10^{12}		
PN_{av} >10 nm	particles/kWh		2.7×10^{12}		

[5] https://lowcarbonpower.org/region/Finland.

3.5.2. Revenues

Literature proposes a price premium for transporting goods with sustainable maritime fuels (Schwartz et al., 2022). At the same time, experience has shown that there are cargo owners that pay a premium for green maritime transportation carrying their goods (Viking Line, 2024). However, we decided not to include price premiums of sustainable shipping services in this study, because the potential extra payments are based on bilateral contracts between the cargo owners and the providers of transportation services that concern trade secrets. Simultaneously, the size and level of these payments for sustainable shipping services is hard to predict. As price premiums for green transport services are considered to be 0 € per ton of goods transported in our calculations, no actual transportation volumes are needed to be taken into account in this study.

Instead, we take the potential revenues concerning pooling of vessels within FEUM regulation into account. In the other words, sustainable vessels operating with FEUM compliance surplus are capable of trading their compliance surplus points to vessels having a negative compliance balance with the aid of pooling of vessels. It is expected that there is a lack of green maritime fuels and that only a small percentage of ships can utilize green fuels. At the same time, more than 10,000 ships are within the regulation framework of FEUM. For these reasons, the price of the FEUM surplus points sold to a vessel with a negative amount of compliance points is likely valued close to the penalty of FEUM regulation in pooling.

3.5.3. Costs

Both capital expenditure (CAPEX) and operating expenses (OPEX) are taken into account in our calculations. In addition, cash outflows based on EU ETS and FEUM are calculated.

3.5.3.1. CAPEX. In CAPEX we include investments in engines, tanks, or batteries. The CAPEX is targeted at year 0 for alternative vessels, whereas batteries need to be renewed every 10 years over the vessel's 30-year economic lifetime. The formula for calculating net present costs for ship type considering CAPEX are given in Equation (7).

$$CAPEX_a = \sum_{i=0}^{30} \left(\frac{(MC_{a.i} + TC_{a.i} + BC_{a.i})}{(1+r)^i} \right) \quad \text{Equation 7}$$

where:

a, refers to different ship types

i, refers to different years of operations.

$MC_{a,I}$, refers to Engine investment cost on year i to ship type a.

$TC_{a,I}$, refers to Tank investment cost on year i to ship type a.

$BC_{a,I}$, refers to Battery investment cost on year i to ship type a

r, is the discount rate = 10 %

Costs of different energy modes are collected in Table 8. In Table 8, the USD is worth 0.9 EUROs based on the current exchange rate (GoogleFinance, 2025) (see Table 9).

Table 8
Costs table, CAPEX (Lindstad et al., 2021; Theotokatos et al., 2023; Moon et al., 2024)

	MGO	LNG	LBG	Syn MeOH	Elect. 50-50 Fin-Est
Engine (USD/kW)	400	400	400	600	
Tanks (USD/kW)		600	600	200	
Total €/kW	360	900	900	720	
Battery cost, t = 0 (€/kWh)					455
Battery cost, t = 10 (€/kWh)					305
Battery cost, t = 20 (€/kWh)					244

3.5.3.2. OPEX. The formula for calculating net present costs for ship type "a" considering OPEX are given in Equation (8). For OPEX, we compare energy cost (i.e. fuel or electricity cost) and maintenance costs. At the following stage, emission trading (EU ETS) cost, and FEUM penalties are summed up to the results.

$$OPEX_a = \sum_{i=1}^{30} \left(\frac{(AC_{a.i} + FC_{a.i})}{(1+r)^i} \right) \quad \text{Equation 8}$$

where:

a, refers to different ship types.

$AC_{a,i}$, refers to maintenance costs of ship type "a" year i.

$FC_{a,i}$, refers to fuel costs of ship type "a" year i.

R, refers to discount rate = 10 %

While a battery powered ship likely requires a lower level of manning and a smaller crew than alternative vessel types, this element (manning) is not taken into account in our analyses due to uncertainty regarding the magnitude of its impact. The same applies to insurance costs.

3.5.3.3. Sensitivity analyses. Because of the complexity of forecasting EU ETS prices, sensitivity analyses are conducted. Sensitivity analyses are conducted for different EU ETS Prices; 80€ and 160€. For 2025, 70 %, of EU ETS is calculated according to the regulation time schedule (European Commission, 2025).

3.5.3.4. FuelEU maritime (FEUM). FEUM is a new initiative that was taken into use at the beginning of the year 2025. Based on FEUM, penalties for ships that operate with higher greenhouse gas intensity levels than limited with the regulation will be set to these vessels. In our analyses, the studied ships use only the originally intended main fuel and pilot fuel throughout the study period, and no blending of alternative fuels will be done throughout the study period of 30 years. We also assume that ships will utilize pooling and pay the same amount of money for pooling that would have been the size of the penalty otherwise. For that reason, we do not allocate 10 % extra penalties for ships that may have been subject to penalties on operating with a too high a greenhouse gas intensity figure on consecutive years. The ships that have a positive compliance balance will sell these compliance surplus points to MGO powered ships under FEUM regulation – This is considered as revenue from FEUM. Greenhouse gas intensities we have utilized in our calculations are presented in Table 10.

The environmental cash inflows and outflows are calculated with Equation (9). Equation (9) is formulated to take FEUM costs for participating in a pool – and revenues from selling a place in a pool, as well as EU ETS payments into account.

$$ENVIR_a = \sum_{i=1}^{30} \left(\frac{(FEUM_{a.i} + EUETS_{a.i})}{(1+r)^i} \right) \quad \text{Equation 9}$$

$FEUM_{a,i}$, refers to FEUM pooling cost/revenue of ship type "a" year i {FEUM revenue is considered as a negative value}.

$EUETS_{a,i}$, refers to sum of EUETS allowances needed to be purchased for ship type "a" year i.

r, refers to discount rate = 10 %

3.5.4. Combining the discounted cashflows

All the discounted cash outflows and cash inflows are added together using Equation (10).

$$Total\ CASHFLOWS_a = CAPEX_a + OPEX_a + ENVIR_a \quad \text{Equation 10}$$

where, "a", refers to type of ship.

Table 9
Costs table, OPEX (Iannaccone et al., 2020; Safty4Sea, 2022; Pratschner et al., 2023; Corvus, 2025; Globalpetrolprices, 2025; Theotokatos et al., 2023; Ship&Bunker, 2025)

OPEX	MGO	LNG	LBG	Syn MeOH	Elect. 50-50 Fin-Est	Electricity (Finland)	Electricity (Estonia)
Fuel price (€/ton)	700	900	1650	1100			
Electricity (€/kWh)					0.126	0.109	0.142
Maintenance costs/year, €	2,421,644	2,553,395	2,563,628	2,393,287	1,937,315	1,937,315	1,937,315

Table 10
Greenhouse gas intensities for the studied vessels (g CO_2e/MJ) (SustainableShips, 2025).

	MGO	LNG	LBG	Synthetic methanol	Electric
WtW Main fuel	90.6	91	46.2	40.5	0
Total WtW (Takes MGO as pilot fuel into account)	90.6	90.99	46.91	45.84	0

4. Results

4.1. Impact assessment

The life cycle impact assessment results across all propulsion options are summarized in Table 11, providing a comparative overview of environmental performance across climate, air quality, resource use, and toxicity-related categories.

4.2. Interpretation

4.2.1. Carbon footprint (results from Tier-1)

This section presents the comparative assessment of the life cycle greenhouse gas (GHG) emissions of the six marine propulsion pathways over a 30-year operational lifetime using inventory data from tier-1, expressed in tonnes of CO_2 equivalent (tCO_2-eq). The analysis includes both upstream and operational emission sources, as detailed in Fig. 4. To better understand the emission drivers, a contribution analysis was conducted for each pathway, breaking down the relative share of emissions from fuel production, combustion, electricity/fuel consumption, and battery/ICE manufacturing. The results are discussed in ascending order of total emissions, beginning with the most environmentally sustainable option.

The battery-electric vessel powered entirely by renewable electricity

Table 11
Tier- 2 Impact assessment results.

Impact category	Unit	Operation of MGO vessel 30yrs	Operation of LNG Ropax Vessel	Operation of LBG Vessel 30yrs	E-MeOH- Vessel operation (30yrs)	Operation B:Vessel (50 % Fingrid+50 % Estonian Grid	Operation of Electric ROPAX Vessel (100 % Fingrid)
Global warming	kg CO2 eq	4,105,382,076.4	3,937,170,068.6	1,864,737,539.6	1,402,879,709	1,076,593,897.0	565,704,111.9
Stratospheric ozone depletion	kg CFC11 eq	229.1	221.6	400.0	590	425.9	241.1
Ionizing radiation	kBq Co-60 eq	20,189,693.0	8,134,910.5	74,033,129.7	5,676,149,136	375,521,207.8	690,906,951.6
Ozone formation, Human health	kg NOx eq	21,149,219.8	4,463,650.0	1,682,569.9	1,785,187,523	3,777,919.8	1,864,278.2
Fine particulate matter formation	kg PM2.5 eq	3,785,214.7	1,300,656.9	379,337.2	276,939,229	5,176,663.1	1,402,029.2
Ozone formation, Terrestrial ecosystems	kg NOx eq	49,977,499.3	8,359,813.5	3,945,561.1	4,483,186,094	3,886,947.2	–
Terrestrial acidification	kg SO2 eq	57,854,440.1	8,987,373.1	4,477,436.5	5,315,780,338	8,491,394.0	3,582,278.2
Freshwater eutrophication	kg P eq	69,523.0	52,950.8	23,707.5	1,752,572	1,058,704.8	722,834.7
Marine eutrophication	kg N eq	33,300.1	22,543.5	3100.6	241,934	62,963.8	55,543.9
Terrestrial ecotoxicity	kg 1,4-DCB	9,505,379,956.2	8,133,929,435.3	1,828,295,424.6	134,431,358,172	18,525,149,322.2	15,605,507,980.3
Freshwater ecotoxicity	kg 1,4-DCB	8,641,294.7	6,304,210.4	12,330,937.4	401,866,713	316,262,142.5	297,136,123.1
Marine ecotoxicity	kg 1,4-DCB	22,248,470.4	17,204,011.7	17,080,565.3	618,138,462	423,145,483.5	395,438,926.2
Human carcinogenic toxicity	kg 1,4-DCB	139,477,081.3	160,616,275.6	36,692,005.1	500,858,045	466,070,116.3	364,392,540.7
Human non-carcinogenic toxicity	kg 1,4-DCB	182,180,746.8	144,120,778.1	142,209,708.9	3,819,406,917	5,106,112,896.5	4,439,383,211.7
Land use	m2a crop eq	25,818,053.5	20,966,419.1	12,530,392.1	1,578,569,455	147,190,921.1	220,681,704.8
Mineral resource scarcity	kg Cu eq	1,815,839.0	1,400,019.7	701,032.4	13,091,597	19,291,044.2	18,961,411.8
Fossil resource scarcity	kg oil eq	1,172,538,256.4	1,098,625,070.0	32,389,202.9	−462,388,918	279,996,473.4	140,937,909.5
Water consumption	m3	1,803,982.0	2,144,644.1	1,681,416.4	31,527,966	9,595,162.8	7,329,836.9

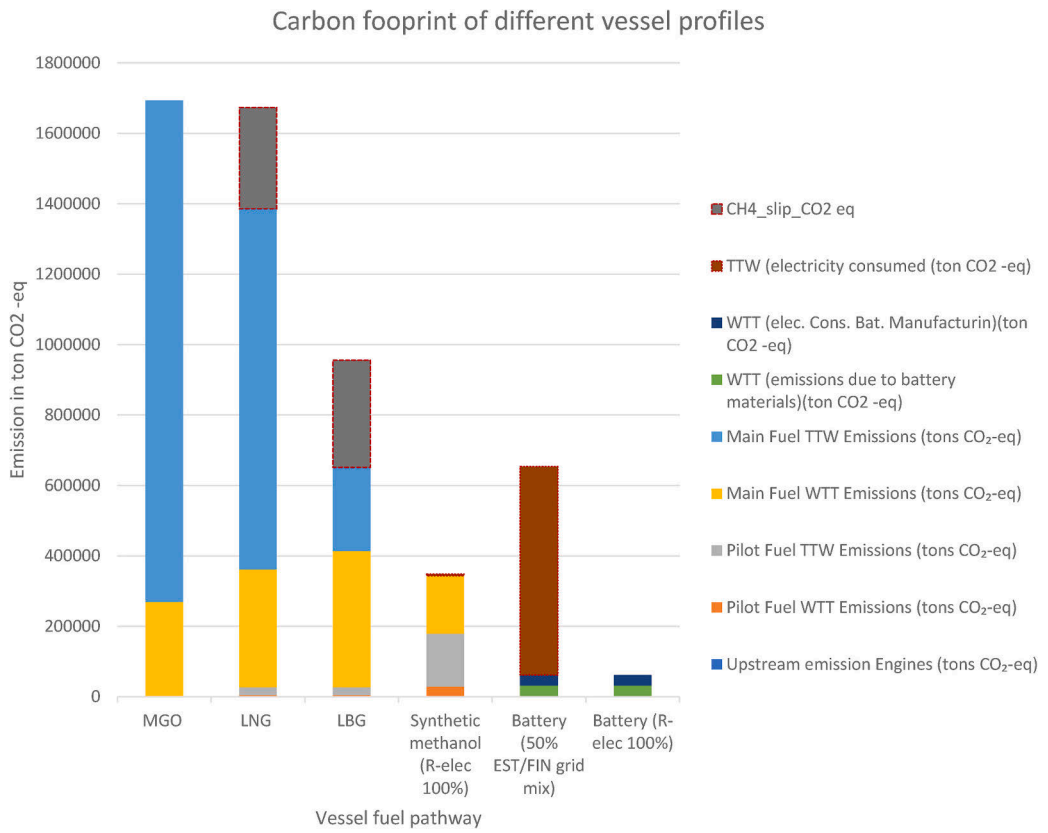

Fig. 4. Carbon footprint results of different vessels scenarios operating under different fuel pathways.

demonstrates the lowest total life cycle emissions, at approximately 61,881 tCO_2-eq. The contribution analysis shows that 100 % of emissions are from battery manufacturing, primarily driven by energy consumption during production using the Chinese electricity grid (carbon intensity: 0.5572 $kgCO_2$/kWh). There are no operational emissions, making this pathway a near-zero-emission solution. These findings reinforce the consensus that direct electrification is the most effective decarbonization strategy for short-sea and inland shipping, as also noted by Fan et al. (2021) and EMSA (2023).

Next in performance is synthetic methanol produced using 100 % renewable electricity, with life cycle emissions of approximately 348,446 tCO_2-eq. Contribution analysis reveals that most emissions arise from pilot fuel combustion (~43 %) and main fuel production (~47 %), with smaller contributions from electricity use during synthesis (~1.3 %). Despite the assumption of carbon-neutral combustion for the main fuel, upstream production processes remain energy-intensive. These findings align with Brynolf et al. (2018), who emphasize the need for clean electricity in synthetic fuel production to realize full climate benefits.

The battery-electric vessel powered by a 50/50 mix of Finnish (Fingrid) and Estonian (Tallinn) grid electricity ranks third, with total emissions of ~654,002 tCO_2-eq. Operational electricity consumption dominates the footprint, accounting for ~90 % of the total. This is driven by the contrast in grid carbon intensity: Finnish grid emits only 36 gCO_2/kWh, while Tallinn's grid emits 479 gCO_2/kWh. Battery manufacturing contributes the remaining ~10 %, based on production powered by the Chinese grid. These results underline the importance of grid decarbonization in parallel with vessel electrification, echoing the findings of Fan et al. (2021).

Liquefied biogas (LBG) produces total emissions of ~955,342 tCO_2-eq. Contribution analysis shows a relatively balanced profile: methane slip accounts for ~32 %, main fuel production for ~41 %, and combustion emissions for ~25 %. While LBG benefits from its biogenic carbon origin, its climate advantage is substantially offset by methane leakage. As previously highlighted by spoof-Tuomi, and Niemi (2020), the deployment of advanced methane mitigation technologies is crucial for ensuring that biogas can serve as a genuinely low-carbon fuel option within the maritime sector.

Liquefied natural gas (LNG) follows LBG with emissions of ~1.67 million tCO_2-eq. Despite lower CO_2 combustion emissions than MGO, LNG's methane slip (~287,811 tCO_2-eq, ~17 %) is a major contributor to its overall footprint. Contribution analysis also indicates significant shares from main fuel production and TTW CO_2 emissions. The results reflect concerns raised Spoof-Tuomi and Niemi (2020) that LNG's use as a transitional marine fuel may offer only marginal climate benefits without strong methane emission controls.

Marine gas oil (MGO) ranks as the most carbon-intensive pathway, with life cycle emissions totalling ~1.69 million tCO_2-eq. The

Table 12
Special characteristics of different GHG emission profiles considering different ferries.

Main energy source of the ferry	Special characteristics considering carbon footprint.
MGO	Over 80 % of the GHG emissions generated as tank-to-wake emissions.
LNG	Tank to wake GHG emissions form 80 percent of the GHG emissions out of which a remarkable portion is methane slip
LBG	40 % of the GHG emissions are generated before utilization of the fuel onboard. Half of the tank-to-wake GHG emissions are based on methane slip.
Synthetic methanol (renewable electricity)	Half of the GHG emissions are based on well-to-tank-emissions and other half are emitted as tank-to-wake emissions of combusting MGO as a pilot fuel.
Battery (50 % Finnish grid-50 % Estonian grid)	90 % of the GHG emissions are related to electricity generation onshore. The rest 10 % were generated during the manufacture of the batteries.
Battery (100 % renewable energy)	All the GHG emissions are related to manufacturing of the batteries out of which half has been formed during the material acquisition and other half in manufacturing the battery packs.

contribution analysis shows that over 84 % of emissions are from direct combustion, with upstream emissions from fuel production making up the remainder. As a fossil-based fuel with no decarbonization pathway, MGO is incompatible with long-term climate targets. Gilbert et al. (2018) similarly highlight the necessity of moving away from traditional marine fuels to meet international emission reduction goals. The specific characteristics of the GHG emissions emitted by different energy sources are gathered in Table 12.

4.2.2. Analysis and interpretation of carbon footprint results (Tier-1 and Tier-2)

We converted WTW climate results to a service-based view by partitioning emissions per nautical mile into "useful" (attributable to delivered shaft power) and "wasted" (attributable to conversion and ancillary losses), using technology-specific shaft-to-fuel efficiencies inferred from Tier-1 (≈45 % for MGO/LNG/LBG, 40 % for methanol DF, 85 % for battery-electric). Applying these same efficiencies to Tier-2 totals (SimaPro, ReCiPe Midpoint background) clarifies that thermal options allocate more than half of their WTW burden to conversion losses (MGO/LNG/LBG), whereas battery-electric allocates the majority to useful output, with a small, wasted Fig. 5.

4.2.3. Other environmental impact categories (Tier-2)

A comparative life cycle impact assessment using tier-2 SimaPro results (see Appendix 6.2) shows that full electrification, when powered by low-carbon electricity, offers the most substantial climate benefits—up to 86 % reduction in global warming potential (GWP) compared to marine gas oil (MGO). However, this transition introduces trade-offs in mineral resource demand, toxicity, and water consumption, particularly linked to battery production and upstream electricity generation. Bio-based fuels such as liquefied biogas (LBG) and electro-methanol (e-MeOH) provide moderate GWP reductions but carry significant burdens in land use, eutrophication, and ecotoxicity, while liquefied natural gas (LNG) offers only marginal climate benefits and maintains high air pollution impacts. These findings underscore that no single propulsion pathway is environmentally dominant across all impact categories. Electrification remains the most promising strategy for short-sea RoPax ferries, but its sustainability hinges on responsible upstream supply chain management. Complementary efforts like CountEmissionsEU—based on ISO 14083[6]—reinforce the importance of transparent Scope 3 emissions reporting, ensuring that green transport solutions are not only low-emission in operation but also sustainable across their full life cycle. This means that using electricity alone is not sufficient; the energy must be demonstrably renewable, and its environmental footprint must be accounted for comprehensively (Paris et al., 2021).

4.3. Economic impacts (tier-1 results)

The battery-powered ferry has the highest capital costs when compared to other vessel types. This is because of the costs of three battery packs that are needed during the lifetime of the vessel. The lowest capital costs are for the marine gas oil powered ships. The vessel operating with synthetic methanol has the highest operating expenses, and simultaneously, the ship powered up with synthetic methanol has the highest overall costs followed by LBG, when EU ETS and FEUM related costs and revenues are not taken into consideration. The CAPEX and OPEX figures are given in Fig. 6. When CAPEX and OPEX figures are summed up, all-electric vessel has around similar level of costs with a ship utilizing LNG as its main fuel.

All-electric ships turn out to be the most economic option out of the studied vessel types when also environmental costs and revenues are summed up to the CAPEX and OPEX figures. The net present costs are the lowest for the battery-based ships due to the effects of FEUM pooling and the reason that no EU ETS allowances need to be purchased by all-electric ships. When considering environmentally more sustainable options such as battery-based ferry, LBG, and synthetic methanol, the business cases for these options will improve remarkably when EU ETS and FEUM regulations are taken into account. As an example, the position of MGO as the most inexpensive option considering the CAPEX and fuel costs for 30 years, turns out to be one of the most expensive alternatives when FEUM and EU ETS are considered in the calculations. The net present costs including environmental costs and revenues for different ship types are illustrated in Fig. 7.

4.4. Environmental and economic impacts (tier-1)

In this section we combine the economic findings with environmental footprints of different vessel types. The results show that when 100 % renewable electricity is used for charging the batteries of all-electric ferry, both the environmental footprint and cost of ownership are the lowest for all-electric battery-based ferry, Fig. 8. LNG and MGO powered vessels cause the biggest costs, mostly because of the FEUM and EU ETS regulations. These ship types (LNG&MGO) also emit the highest amounts of greenhouse gas emissions when measured with carbon dioxide equivalent emissions considering global warming potential for 100 years.

In Fig. 8, EU ETS is set to the level €100 per ton CO2 equivalent emissions emitted.

A battery-based all-electric ferry seems to be the most viable option for the route between Helsinki and Tallinn. The capital costs for purchasing the batteries are still high, but the prices of battery packs are coming down year after year (BloombergNEF, 2024). The good result of the battery-based ferry was strongly related to the regulations that steer costs towards polluting vessels with high greenhouse gas intensities, whereas the greenhouse gas emissions that all-electric ships generate during the operations are minimal. When considering both carbon footprint and costs of operations during the next 30 years, all-electric battery-based ferry seems to be a good option. Discussions with the distribution grid operators in Helsinki and Tallinn also show that

[6] https://www.imo.org/en/ourwork/environment/pages/fourth-imo-greenhouse-gas-study-2020.aspx.

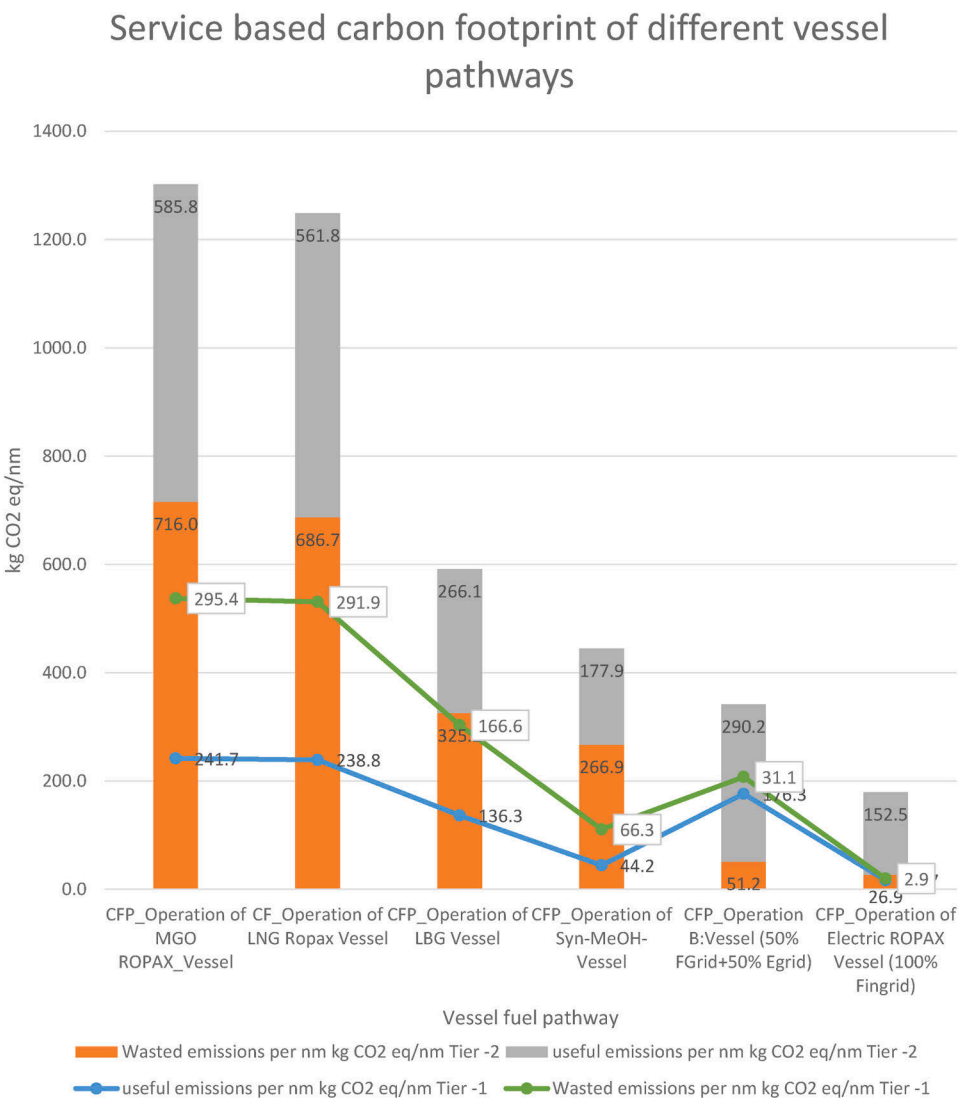

Fig. 5. Harmonized tier 1 & tier 2 carbon footprint results of different vessel pathways represented in units of work done.

charging an electric ship at these capacities is not a significant challenge but a business opportunity.

In addition, a battery-based ferry is more silent and causes less vibration in the hull of the ship when compared to power sources based on internal combustion engines. As a result of lower vibrations, lighter hull structures are possible to be used. However, this effect was not considered in the analysis.

Overall, the future of all-electric battery-based ships seems promising. However, it has to be mentioned that onshore batteries and charging infrastructure needs to be arranged and built to make the loading of ship batteries possible. The role of onshore infrastructure could be studied in the future research. In addition, buying and selling of ships is typically part of the business, and in the future studies it could be investigated how well all-electric battery-powered ships can be moved to alternative shipping routes considering the routes of second and third owner of the vessel. In the wider scale, the industry would benefit of standardized vessel charging systems, so that the charging of batteries would be possible on alternative routes if needed.

Based on this study, the utilization of LNG and MGO seem to be having around same GHG emissions and lifetime costs. A big question is the methane slip from the LNG combustion, and the methane slip will largely determine whether LNG is better option than MGO as an energy

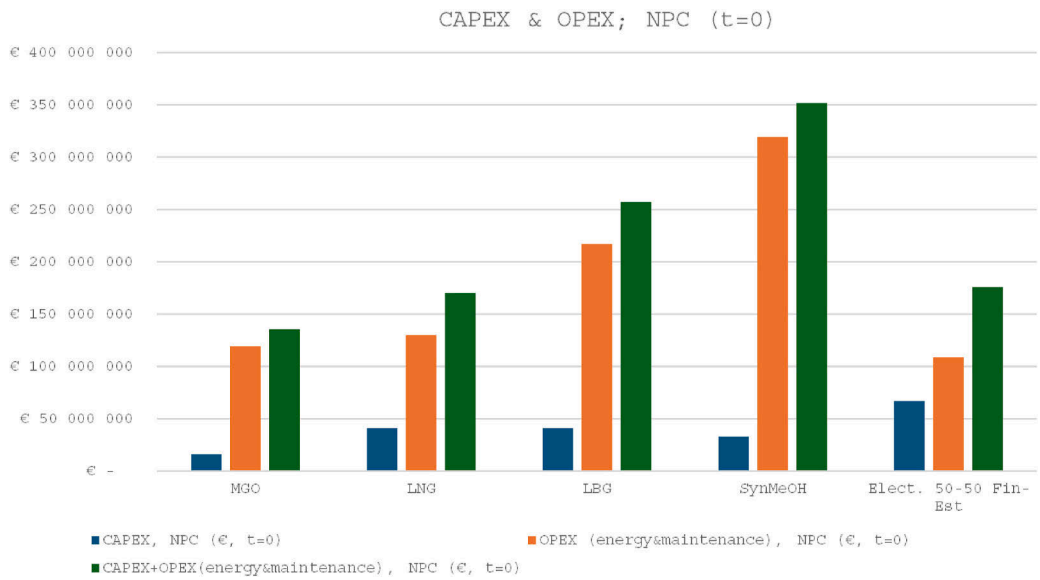

Fig. 6. Capex & opex (without EU ETS and FEUM).

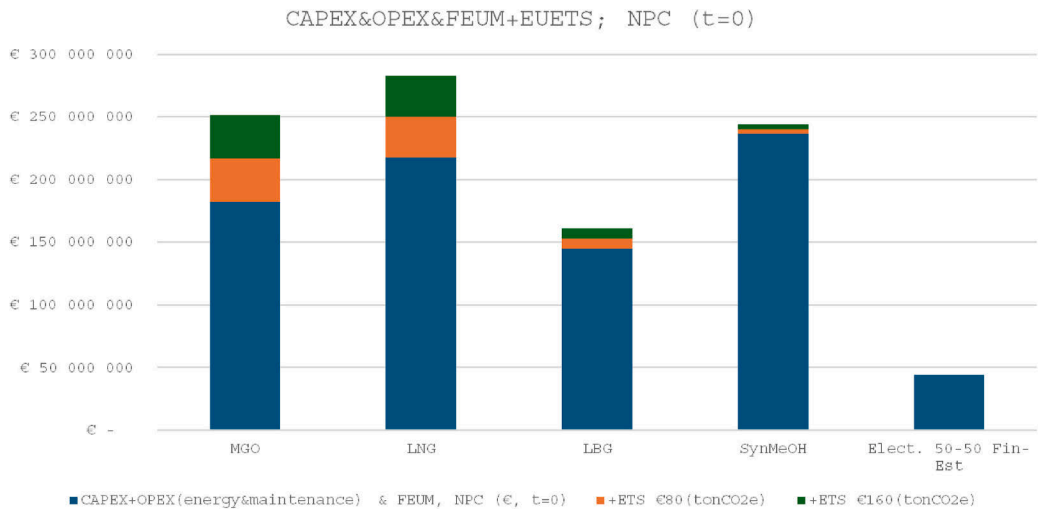

Fig. 7. Net present cost of different energy types.

source. It is not only the GHG emissions but the ways how FEUM and EU ETS regulations consider the methane slip that determines if MGO or LNG powered ships need to pay more on their environmental footprint. However, it seems more promising to utilize and blend biogas on dual fuel (LNG) engines than HVO in diesel engines as a long-term strategy.

4.5. Environmental pricing (tier-2)

In this study, environmental prices caused by different prime movers during the lifetime of the ship (30 years) were calculated with SimaPro-software for different environmental themes. In environmental pricing, central pricing figures dedicated to be used in LCA studies were utilized (Delft, 2023). The environmental prices for different environmental themes for different vessel types are listed in Table 13.

5. Conclusion

This study has investigated the emission reduction potential and

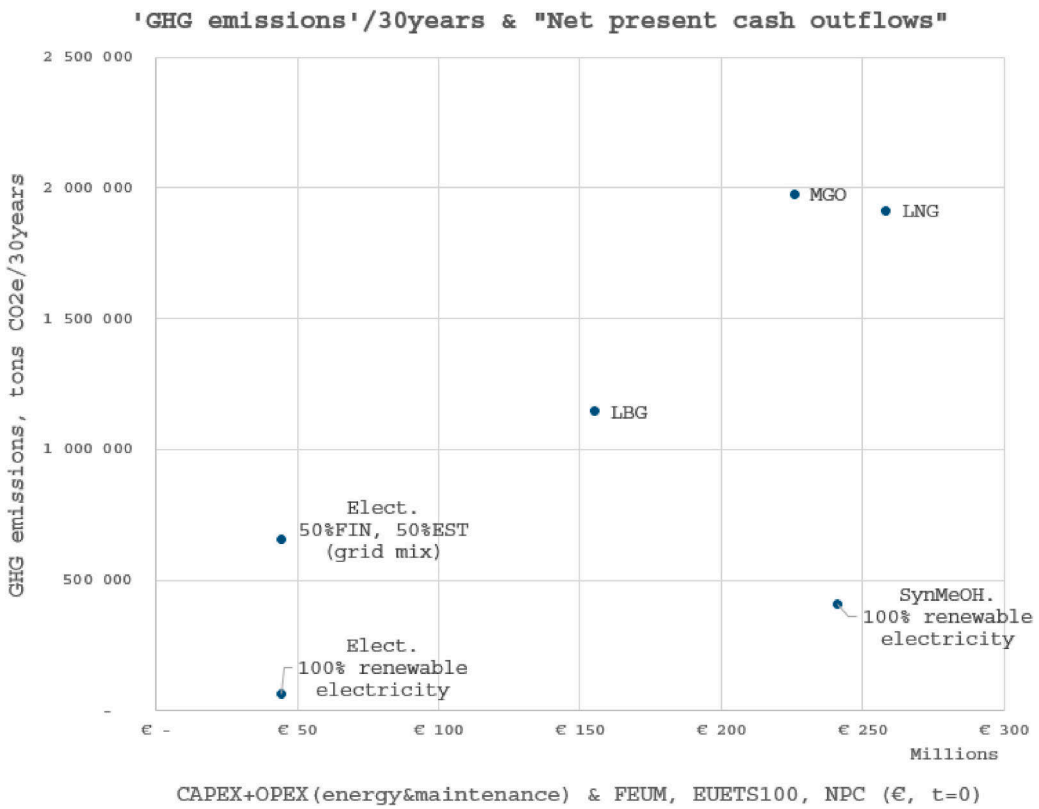

Fig. 8. Net present cash outflows and CO2 equivalent emissions during the lifetime of the vessel.

Table 13
Environmental prices for the various impact categories for each vessel type.

		Environmental prices during the lifecycle in 1000 €					
	Unit of analyses	MGO	LNG	LBG	E-MeOH (100 % Fingrid)	All-electric (50 % Fingrid+50 % Estonian Grid)	All electric (100 % Fingrid)
Global warming	kg CO2 eq	533700K€	511832K€	242416K€	182374K€	139957K€	73542K€
Stratospheric ozone depletion	kg CFC11 eq	7K€	6K€	12K€	17K€	12K€	7K€
Ionizing radiation	kBq Co-60 eq	85K€	34K€	312K€	23953K€	1585K€	2916K€
Ozone formation, Human health	kg NOx eq	39338K€	8302K€	3130K€	3320449K€	7027K€	3468K€
Fine particulate matter formation	kg PM2.5 eq	320608K€	110166K€	32130K€	23456753K€	438463K€	118752K€
Ozone formation, Terrestrial ecosystems	kg NOx eq	20791K€	3478K€	1641K€	1865005K€	1617K€	0K€
Terrestrial acidification	kg SO2 eq	305471K€	47453K€	23641K€	28067320K€	44835K€	18914K€
Freshwater eutrophication	kg P eq	260K€	198K€	89K€	6555K€	3960K€	2703K€
Marine eutrophication	kg N eq	475K€	321K€	44K€	3448K€	897K€	792K€
Terrestrial ecotoxicity	kg 1,4-DCB	6083K€	5206K€	1170K€	86036K€	11856K€	9988K€
Freshwater ecotoxicity	kg 1,4-DCB	181K€	132K€	258K€	8399K€	6610K€	6210K€
Marine ecotoxicity	kg 1,4-DCB	71K€	55K€	55K€	1978K€	1354K€	1265K€
Human carcinogenic toxicity	kg 1,4-DCB	556514K€	640859K€	146401K€	1998424K€	1859620K€	1453926K€
Human non-carcinogenic toxicity	kg 1,4-DCB	12935K€	10233K€	10097K€	271178K€	362534K€	315196K€
Land use	m2a crop eq	2556K€	2076K€	1241K€	156278K€	14572K€	21847K€
Mineral resource scarcity	kg Cu eq	25K€	20K€	10K€	183K€	270K€	265K€
Fossil resource scarcity	kg oil eq	32831K€	30762K€	907K€	−12947K€	7840K€	3946K€
Water consumption	m3	734K€	873K€	684K€	12832K€	3905K€	2983K€

economic feasibility of transitioning to a fully battery-electric shipping concept design around a large RoPax (cruise) ferry. Assuming access to 100 % renewable energy and considering the impact of EU ETS and FEUM, the study found that fully battery-electric propulsion is a much better option both in terms of GHG emissions and total cost of ownership. Accounting for the current grid mix in the operational area of the case vessel, the GHG emissions are in the range of e-methanol while the difference in total cost of ownership is significantly lower.

Our study contributes to the recent interest in electric shipping. The size of the studied vessel (and its 110MWh battery pack) is considerably higher than in recent similar assessments of electric ferries (Percic et al., 2020; Korberg et al., 2021). The study also demonstrates the necessity of rethinking the shipping and charging operations (i.e. the "electric shipping concept"). Our study suggests that battery-powered vessels are both more competitive and climate friendly than other alternative power sources discussed in the context of short-sea shipping, mainly due to way the benefit from the FEUM regulation. Moreover, the electric shipping concept performs well also in the context of environmental cost, which illustrates an additional benefit of FEUM. Hence, all-electric battery-powered vessels may offer a fast pathway to decarbonize this important part of the maritime industry.

Utilization of all-electric battery powered ships influences various policies. For instance, maritime policy, transport policy, energy policy, environmental policy, and innovation policy are all affected by the utilization of all-electric battery powered ferries. Many of the existing policies are developed several years back to cover the usage of conventional fossil fuel powered vessels built around internal combustion engines. From an environmental policy point of view, all-electric battery powered ships cause most of the air emissions during the battery manufacturing phase, whereas GHG emissions and SOx, NOx and particulate matter emissions of these ships during the operations are minimal to non-existent. In reference to the results, battery-electric minimizes both total WTW per nm and the wasted share; synthetic methanol and LBG reduce totals relative to fossil options but retain high wasted fractions due to thermal conversion and methane slip.

As an example, EU ETS is measuring tank-to-wake emissions making all-electric battery powered ships a good and sustainable option both environmentally and economically. Another example concerns employment policies that are traditionally designed to handle the construction and maintenance issues of the ships with a complex powertrain based on internal combustion engines. All-electric battery powered ships have fewer moving parts than is the case with powertrains served by internal combustion engines that need almost constant care during the sea crossings. The recycling of batteries is an important theme under environmental policy, and the used batteries can be often recycled to be used in other applications when their lifetime has come to an end in serving the ship. From the energy policy point of view, batteries need to be charged practically every port call with the aid of the needed charging infrastructure, while ships with internal combustion engines are bunkered often on weekly or bi-weekly basis.

Future research in electric shipping could address some of the limitations of our study. As mentioned, we have not considered the effects of a potentially lighter hull and reduced maintenance needs of a fully electric vessel. Moreover, short sea shipping may entail a wide variety of vessels and operational profiles. Hence, our study could be extended to other types of vessels, such as container feeders, or longer routes and routes with longer time for recharging. Perhaps most importantly, more research is needed in the onshore facilities offered by ports and other actors. These infrastructure investments are likely to be substantial but can also open up avenues for new offerings and business models for ports and energy distributors.

CRediT authorship contribution statement

Anthony Katumwesigye: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Henry Schwartz:** Writing – original draft, Methodology, Investigation, Formal analysis. **Magnus Gustafsson:** Writing – review & editing, Supervision, Investigation, Funding acquisition, Conceptualization. **Magnus Hellström:** Writing – review & editing, Supervision, Project administration, Funding acquisition, Conceptualization.

Data statement

The data supporting the findings of this study are available from the corresponding author upon reasonable request. All relevant datasets generated and/or analysed during the current study were derived from publicly available sources, proprietary databases under institutional licenses, and internal technoeconomic models developed for this research. Due to licensing restrictions and confidentiality agreements related to some of the industrial and economic datasets, direct public access to the raw data is not possible. However, aggregated results, methodological details, and key assumptions necessary for reproducibility have been included in the article and supplementary materials. Further information may be provided by the authors to authorised researchers on a case-by-case basis.

Declaration of interest

This research was conducted as part of a collaborative project involving academic and industry partners. While some technical data (e.g., vessel design specifications) were provided by a shipyard participating in the feasibility consortium, the authors affirm that the analysis and conclusions presented in this paper are independent and free from any commercial or financial bias. The authors declare no other competing interests.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

We acknowledge the collaboration with the consortium partners and PBI, who all generously shared data and showed interest in our study. Yet, all the conclusions and possible remaining errors are ours.

6 Appendix

6.1 Inventory data

A: Inventory data for Marine engine materials (Processing and manufacturing emission footprint)- sources: Guven and Kayalica (2023), (Perčić et al., 2022)

Unit	Material	CO_{2} (g)	N_{2} O (g)	CH4 (g)	NOx (g)	Water (m3)	Energy (MJ)
1 kg	Cast iron	441.9	0.005	3.447	1.073	0.001	29
1 kg	Oil and grease	7.3	0	0.009	0.011	0	37
1 kg	Plastic	3000	0.243	20.693	4.149	0.007	87
1 kg	Rubber	3500	0.086	7.146	4.633	0.005	53
1 kg	Paint	5500	0.173	21.317	7.567	0.008	125
1 kg	Zinc	2400	0.047	5.286	1.846	0.026	42
1 kg	Lead	496.6	0.009	6.935	1.036	0.002	24
1 kg	Aluminium	2600	0.06	5.944	2.398	0.059	36
1 kg	Copper	2200	0.046	5.128	2.471	0.006	48
1 kg	Steel	2000	0.013	3.544	2.094	0.001	21

B: Inventory data for lithium iron phosphate (LFP) Battery materials and Assembly – sources: Guven and Kayalica (2023),

Unit	Material	CO_{2} (g)	N_{2} O (g)	CH4 (g)	NOx (g)	Water (m3)	Energy (MJ)
1 kg	Graphite	4600	0.097	10.599	14.013	0.024	90
1 kg	DMC	1200	0.021	4.518	1.059	0.004	37
1 kg	EC	334.43	0.005	1.218	0.283	0.001	10
1 kg	LiPF6	9900	0.198	21.596	9.059	0.057	176
1 kg	PVDF	2000	0.052	5.354	1.909	0.006	36
1 kg	Aluminium	2600	0.06	5.944	2.398	0.059	36
1 kg	Copper	2200	0.046	5.128	2.471	0.006	48
1 kg	Steel	2000	0.013	3.544	2.094	0.001	21
1 kg	PET	2400	0.053	15.163	2.528	0.008	72
1 kg	PP	1500	0.032	21.614	1.707	0.008	76
1 kg	PE	1200	0.022	21.511	1.592	0.007	64
1 kg	BMS	22100	0.52	55.426	18.629	0.093	394
LFP pack							
1 kg	LFP	8900	0.166	18.609	14.311	0.045	60

C: Inventory data for upstream for fuel production: sources e-MeOH; Peppas et al. (2024), Gilbert et al. (2018).

Fuel	Process block	Parameter (MJ/kg product)	Central value (MJ/kg)	source:Peppas et al. (2024)
e-MeOH	Electrolysis H_2	Electricity → MJ/kg H_2	201.6–205.2	56–57 kWh/kg × 3.6;
e-MeOH	CO_2 supply – DAC	Electricity → MJ/kg CO_2	1.1	Moisture-swing sorbent base (as specified)
e-MeOH	CO_2 supply – flue gas	Utilities → MJ/kg CO_2	*process-specific*	Used Peppas et al. (2024) scenario values
e-MeOH	Hydrogenation to MeOH	Process energy → MJ/kg MeOH	≈5.2	Cu/ZnO/Al_2O_3 loop; integration affects range
e-MeOH	Conditioning	Utilities → MJ/kg MeOH	*dataset*	Propagate with power-mix scenarios
LBG	Anaerobic digestion	Net energy (incl. credits) → MJ/kg CH_4	*pathway-dep.*	Waste feedstocks; allocation in scenarios
LBG	Upgrading	Electricity → MJ/kg CH_4	*dataset*	PSA/membrane ranges
LBG	Liquefaction	Electricity → MJ/kg LBG	≈2.52	0.7 kWh/kg × 3.6
LNG	Upstream + liquefaction	–	–	(Impact intensities remain as kg CO_2-eq/kg; unit is different by definition)
MGO	Refining + distribution	–	–	(Impact intensities remain as kg CO_2-eq/kg)

D: Inventory data for industrial carbon capture process sources: Peppas et al. (2024),

Category	Input/Output	Value	Unit
Material Flows	Carbon dioxide (CO2)	1000	kg/tonne CO2 in
Material Flows	Monoethanolamine (MEA)	1.44	kg/tonne CO2 in
Material Flows	Caustic soda (NaOH)	0.12	kg/tonne CO2 in
Material Flows	Activated carbon	0.07	kg/tonne CO2 in
Material Flows	Water	18.1	kg/tonne CO2 in
Energy	Reboiler duty (thermal energy)	3.2	GJ/tonne CO2 in
Energy	Electricity (amine regeneration)	33.8	kWh/tonne CO2 in
Energy	Electricity (CO2 compression)	64.5	kWh/tonne CO2 in
Product	Carbon dioxide (CO2) (captured)	900	kg/tonne CO2 in

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Category	Input/Output	Value	Unit
Emissions to air	Water	87.5	kg/tonne CO2 in
Emissions to air	Carbon dioxide (CO2)	99.9	kg/tonne CO2 in
Emissions to air	Argon (Ar)	54.8	kg/tonne CO2 in
Emissions to air	Nitrogen (N)	3202.2	kg/tonne CO2 in
Emissions to air	Oxygen (O2)	128.3	kg/tonne CO2 in
Emissions to air	Monoethanolamine (MEA)	0.06	kg/tonne CO2 in
Emissions to air	Ammonia (NH3)	0.03	kg/tonne CO2 in
Emissions to air	Formaldehyde (CH2O)	0.00024	kg/tonne CO2 in
Emissions to air	Acetaldehyde (CH3CHO)	0.00015	kg/tonne CO2 in
Emissions to water	Amine reclaimer waste	2.9	kg/tonne CO2 in

E: Emission data for synthetic/E-MeOh distillation and CO_2 hydrogeneration. Sources: Peppas et al. (2024),

Category	Input/Output	Value	Unit
Material Flows	Alumina (Al2O3)	0.000012	tonnes
Material Flows	Zinc oxide (ZnO)	0.000029	tonnes
Material Flows	Copper oxide (CuO)	0.000062	tonnes
Material Flows	Carbon dioxide (CO2)	1.455	tonnes
Material Flows	Hydrogen (H2)	0.21	tonnes
Energy	Electricity	1170	MJ
Product	Synthetic methanol (e-MeOH)	1	tonnes
Emissions to air	Carbon dioxide (CO2)	0.02	tonnes
Emissions to water	Waste water (kg)	0.63	tonnes

6.2 Other impact categories Results

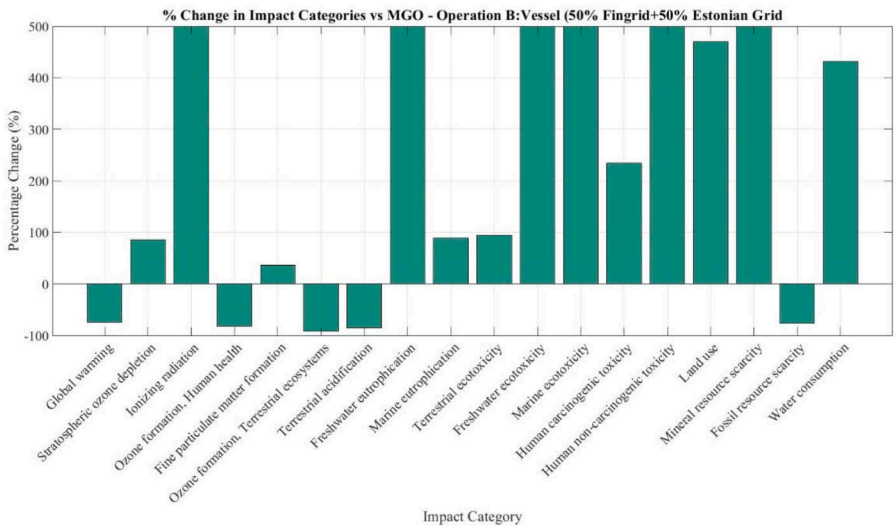

Fig. A1. percentage for switching from MGO to Battery vessel under mixed grid.

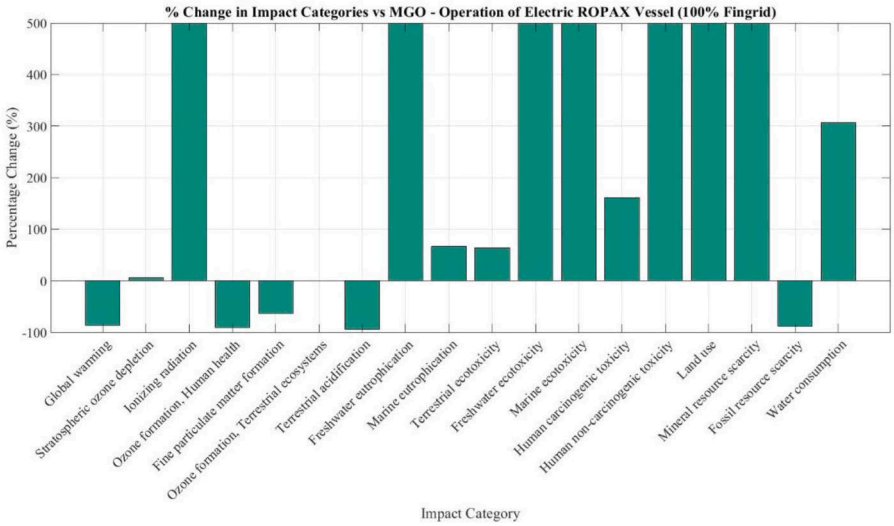

Fig. A2. percentage for switching from MGO Battery vessel under low carbon grid.

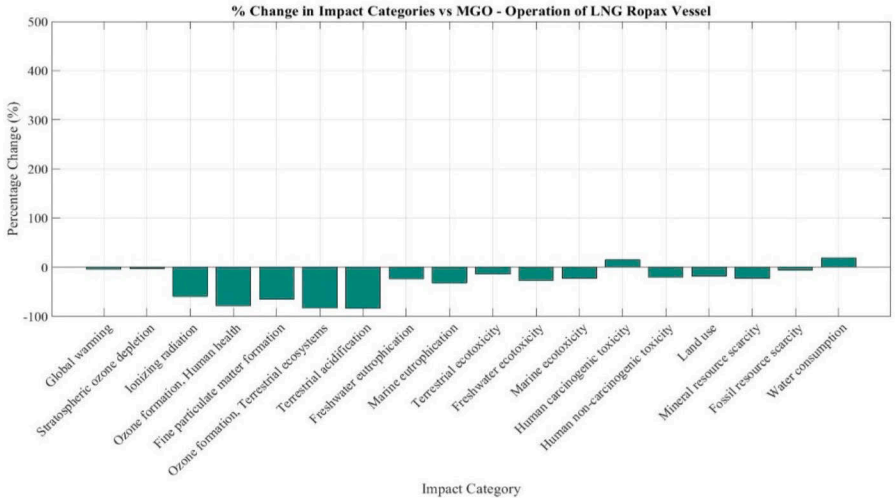

Fig. A3. Percentage for switching from MGO to LNG vessel.

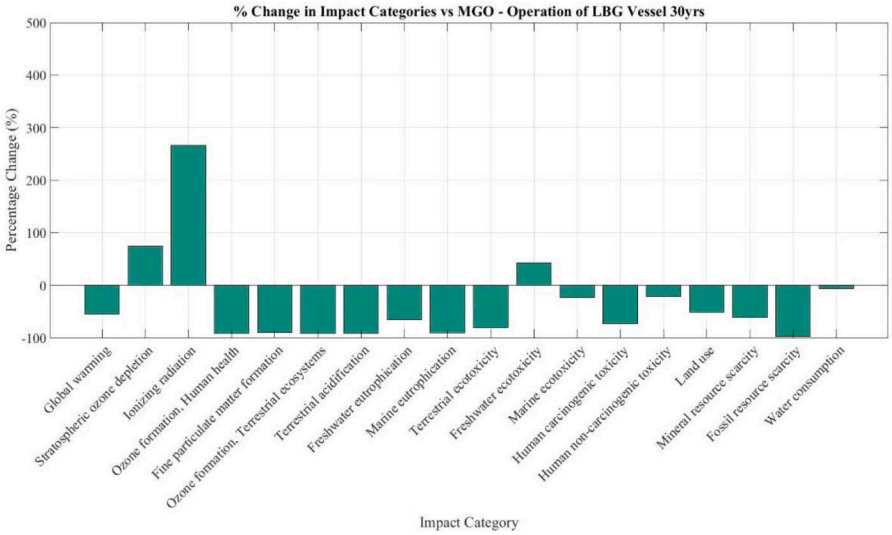

Fig. A4. percentage for switching from MGO Vessel to LBG vessel.

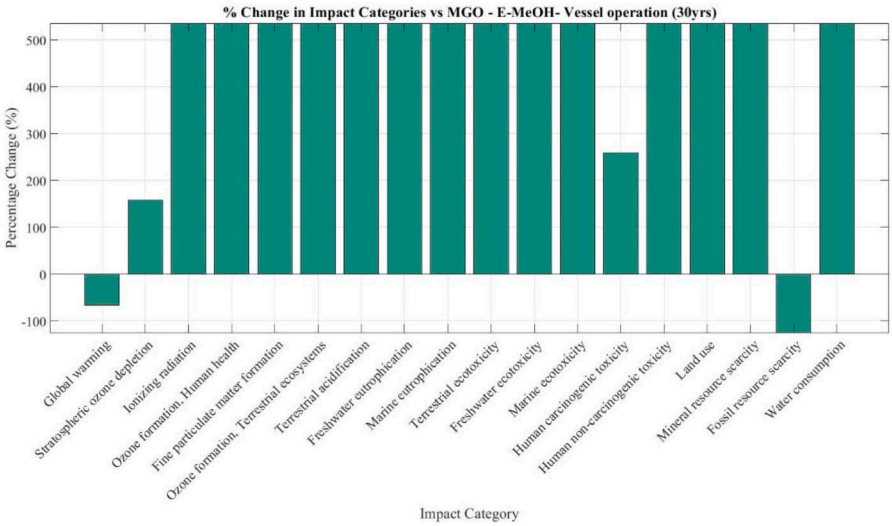

Fig. A5. percentage for switching from MGO Vessel to E-MeOH vessel.

Data availability

Data will be made available on request.

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An integrated life-cycle assessment of three different propulsion pathways for medium-sized wheel loaders under Nordic quarry conditions: A case study

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HIGHLIGHTS

- Battery-electric wheel loaders provide the lowest emissions and RATCO under the assessed Nordic quarry conditions.
- Hydrogen performance depends strongly on production pathway and upstream electricity carbon intensity.
- Shared infrastructure improves BEV economics, while FCEV costs remain strongly influenced by hydrogen price.
- Work-normalised LCA and RATCO enable consistent comparison per tonne of material moved.

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ABSTRACT

Non-road mobile machinery (NRMM) represents a hard-to-abate segment because of high power demand, long operating hours, and limited charging or refuelling flexibility. To address the limited evidence linking life-cycle climate performance and economic competitiveness in NRMM, this study applies an integrated life-cycle assessment (LCA) and techno-economic assessment (TEA) to three propulsion pathways for medium-sized wheel loaders operating under Nordic quarry conditions: diesel internal-combustion engines, battery-electric drivetrains, and hydrogen fuel-cell electric systems. Environmental performance is evaluated using a work-normalised functional unit (kg CO_2-eq t^{-1} moved), while economic performance is assessed using relative-adjusted total cost of ownership (RA–TCO, € t^{-1} moved), complemented by net present cost and Monte Carlo uncertainty analysis. Under the assessed Nordic electricity, energy-price, utilisation, and quarry-duty assumptions, battery-electric wheel loaders achieve the lowest life-cycle greenhouse-gas emissions and RA–TCO across the four countries considered. This outcome is driven by high drivetrain efficiency, comparatively low grid-carbon intensity, and lower energy expenditure per unit of productive work. Hydrogen results are strongly dependent on the production pathway and upstream electricity supply. Renewable hydrogen can reduce life-cycle emissions relative to diesel under low-carbon electricity conditions, but remains cost-disadvantaged in the modelled cases, whereas grid-based electrolytic hydrogen can exceed diesel impacts when supplied by carbon-intensive electricity. Investment support and shared infrastructure improve battery-electric economics, while the hydrogen pathways remain more sensitive to fuel price and infrastructure utilisation. The findings indicate that battery-electric propulsion is the most robust option for the medium-sized wheel-loader application and Nordic quarry conditions evaluated in this study. The results should not be interpreted as a universal ranking for all NRMM applications, duty cycles, electricity systems, or regional markets.

1. Introduction

Non-road mobile machinery (NRMM) is a significant, hard-to-abate source of greenhouse gas (GHG) emissions and energy use, especially in sectors such as construction, mining, and material handling (ICCT, 2016; European Environment Agency (EEA), 2024). While regulatory momentum is growing, NRMM remains less strictly governed than on-road vehicles, leaving a persistent gap in sector-specific decarbonisation strategies (Transport & Environment, 2024a). Recent consensus highlights the need for robust, life-cycle-based evaluations that incorporate both environmental and economic dimensions (IPCC, 2022; Bauer et al., 2025; ISO, 2006).

Although new measures, such as the EU Stage V rules, have addressed conventional pollutants, they do not impose CO_2 limits or

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Abbreviation	Definition
AFIR	Alternative Fuels Infrastructure Regulation
BEV	Battery-electric vehicle (battery-electric wheel loader in this study)
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CED	Cumulative energy demand
CO_2	Carbon dioxide
EHB	European Hydrogen Bank
EoL	End-of-life
FCEV	Fuel-cell electric vehicle (fuel-cell electric wheel loader in this study)
GHG	Greenhouse gas
GWP	Global warming potential
GWP_{100}	Global warming potential over a 100-year time horizon
ICE	Internal combustion engine
ILCD	International Reference Life Cycle Data System (EU ILCD Handbook)
ISO	International Organization for Standardization
LCA	Life-cycle assessment
LCI	Life-cycle inventory
LCIA	Life-cycle impact assessment
NPC	Net present cost
NRMM	Non-road mobile machinery
OPEX	Operating expenditure
PEM	Proton-exchange membrane
PM/PN	Particulate matter/particle number
RA–TCO	relative-adjusted total cost of ownership
RFNBO	Renewable fuels of non-biological origin
SI	Supplementary Information
TTW	Tank-to-wheel
WTT	Well-to-tank
WTW	Well-to-wheel

mandate electrification for NRMM (European Commission, 2016; ICCT, 2016). More recent EU and US policy shifts – including the Alternative Fuels Infrastructure Regulation and targeted zero-emission mandates – signal progress but have yet to deliver clear, actionable decarbonisation pathways for the sector (European Commission, 2023a; Transport & Environment, 2024a; CARB, 2023, 2025).

A parallel regulatory momentum is evident in the United States, exemplified by California's In-Use Off-Road Diesel-Fueled Fleets Regulation and the Zero-Emission Technology Application (ZETA), as well as targeted mandates for zero-emission equipment (CARB, 2023, 2025). National-level analyses increasingly emphasise the heterogeneity of duty cycles across off-road segments, reinforcing the call for transition strategies that are tailored rather than generic (DOE/EPA, 2024).

Electrification and alternative low-carbon powertrains are being piloted and scaled across NRMM sectors, yet deployment is uneven and often constrained by operational requirements, infrastructure readiness, or policy uncertainty (IDTechEx, 2023; Ali et al., 2023). The resulting knowledge gap is particularly acute for medium-sized wheel loaders operating in demanding environments, such as Nordic quarries.

Decarbonisation outcomes in NRMM are highly context-dependent, shaped by operational profiles, infrastructure, and local policy design (Bauer et al., 2025). This highlights the importance of context-specific, integrated analysis—a gap this study addresses for Nordic wheel loaders.

Current practice often overlooks the complex trade-offs between environmental and economic outcomes across the full life cycle of NRMM technologies. Robust comparative studies that integrate these dimensions, especially under real-world operational and energy system constraints, remain limited (Bauer et al., 2025; Peppas et al., 2024).

Therefore, the urgent research need is for integrated, context-specific evaluation of both environmental and economic outcomes for NRMM decarbonisation pathways under real operating conditions.

To address this research gap, the present study conducts a systematic comparison of diesel, battery-electric, and hydrogen fuel-cell propulsion pathways for medium-sized wheel loaders operating in Nordic quarries. By employing an integrated life-cycle assessment and techno-economic framework centred on delivered work, this research aims to generate robust, decision-relevant evidence for both industry practitioners and policymakers.

The remainder of this article is structured to provide a comprehensive and coherent exploration of NRMM decarbonisation. Section 2 reviews the pertinent literature on life-cycle, techno-economic, and policy aspects. Section 3 details the system boundaries, functional units, data sources, and modelling approach. Section 4 presents comparative results across environmental and economic dimensions for both single-machine and fleet deployment scenarios. Section 5 discusses broader implications for procurement practices, infrastructure planning, and policy design, while Section 6 concludes with a synthesis of the principal findings (see Fig. 1).

2. Literature review

A thorough understanding of non-road mobile machinery (NRMM) decarbonisation demands an integrated analysis of environmental, techno-economic, and policy factors. This literature review critically synthesises current evidence in each domain, identifies methodological advances and limitations, and establishes the foundation for the integrated framework adopted in this study.

2.1. Life-cycle evidence for electrified and hydrogen NRMM

A life-cycle perspective is essential for evaluating alternative NRMM propulsion systems, as reductions in direct exhaust emissions may be offset by increased upstream burdens from electricity generation, battery manufacturing, hydrogen production, fuel conditioning, and infrastructure (IPCC, 2022; ISO, 2006; JRC, 2010). The Intergovernmental Panel on Climate Change (IPCC) and leading standards such as ISO 14040/44 and the EU ILCD framework mandate that transport technology choices be assessed using transparent functional units, system boundaries, inventories, allocation procedures, and explicit interpretation of trade-offs.

Comparative life-cycle assessments (LCAs) consistently highlight electricity carbon intensity as a primary determinant of the environmental performance of battery-electric vehicles (BEVs). Lombardi et al. (2017) demonstrated that the life-cycle performance ranking of electric powertrains can be reversed when upstream electricity supply and vehicle-manufacturing burdens are included. Recent studies reaffirm that low-carbon electricity significantly increases the climate benefits of electrification, while carbon-intensive grids diminish them (Koroma et al., 2022; Shafique and Luo, 2022; Naumann et al., 2024; Bauer et al., 2025). Importantly, the environmental advantage of BEVs cannot be inferred from the absence of tailpipe emissions alone (Paul et al., 2024; Zhang et al., 2023).

Battery manufacturing shifts environmental burdens from operation to production, amplifying impacts related to resource depletion, toxicity, and other midpoint indicators, even when life-cycle GHG emissions decline (Eltohamy et al., 2024; Paul et al., 2024; Zhang et al., 2023). Critical modelling parameters include battery chemistry, production energy source, usable depth of discharge, cycle life, replacement timing, and end-of-life management (Dai et al., 2022; Notter et al., 2010). These impacts must be contextualised by operational savings over the machine's lifetime, rather than interpreted in isolation.



Fig. 1. Site visit in Telemark, Norway, documenting an early hybrid-electric NRMM machine configuration and operational context motivating the study.

NRMM-specific research supports these broader conclusions. For example, Salman and Chen (2013) compared a conventional Volvo L150G wheel loader with a plug-in hybrid configuration over 25,000 operating hours, finding that approximately 90% of the diesel baseline's life-cycle impacts arose during operation. Hybridisation reduced global warming, acidification, and eutrophication impacts, but increased abiotic resource depletion due to materials such as lithium, cobalt, and copper. The environmental benefit of hybridisation was more pronounced under low-carbon electricity, confirming that energy supply context is a structural factor in propulsion comparisons.

At fleet scale, Peppas et al. (2024) assessed substituting diesel with green hydrogen, e-methanol, and synthetic natural gas across loaders, excavators, and dumpers. Their results showed that while these alternative fuels can substantially reduce GHGs, upstream processes such as electrolysis, compression, and liquefaction add significant energy demand. When such processes rely on carbon-intensive electricity, upstream emissions can erode or even reverse the expected climate benefit. This reinforces the necessity of explicitly representing production route, electricity source, and conditioning requirements for fuels labelled as "green hydrogen" or similar (IEA, 2024).

Hydrogen fuel-cell systems introduce additional manufacturing burdens associated with fuel-cell stacks, catalysts, balance-of-plant components, and high-pressure storage vessels. The use-phase climate performance of hydrogen depends critically on the production pathway (electrolysis, steam methane reforming, or reforming with carbon capture) and system-level factors such as compression, dispensing, transport, and storage, all of which can materially affect well-to-wheel results (Peppas et al., 2024; Bauer et al., 2025; IEA, 2024). As a result, hydrogen LCAs require pathway-specific inventories rather than generic emission factors.

In summary, the LCA literature supports three key conclusions relevant to this study: (1) diesel NRMM is typically dominated by use-phase impacts due to high fuel consumption over long operational lifetimes; (2) BEV pathways transfer a greater share of impacts to manufacturing but can achieve low life-cycle GHG emissions under high utilisation and low-carbon electricity; (3) hydrogen's climate performance is highly sensitive to upstream production and conditioning. These findings justify the use of country-specific electricity mixes, explicit component inventories, battery and fuel-cell replacement modelling, and cradle-to-use boundaries in the present analysis.

2.2. Techno-economic assessment of off-road electrification and hydrogen

Environmental benefits alone are insufficient to guarantee economic viability. Technology adoption in NRMM, particularly in demanding applications such as quarry operations, is shaped by capital cost, energy cost, maintenance, replacement requirements, infrastructure expenditure, utilisation, productivity, financing, and operational reliability (Mocera et al., 2023; Ali et al., 2023; Un-Noor et al., 2022; Bauer et al., 2025). These factors interact differently across diesel, battery-electric, and hydrogen fuel-cell pathways.

Diesel machinery generally offers low initial cost, mature maintenance networks, rapid refuelling, and well-developed fuel-distribution infrastructure (ICCT, 2016). Its economic exposure centres on fuel consumption, price volatility, maintenance, and carbon-related charges.

High-utilisation operations accumulate substantial lifetime fuel expenditure, even when purchase price is relatively low.

Battery-electric machinery, while often more expensive upfront (machine and charging infrastructure), can achieve lower operating costs per unit of delivered work due to higher drivetrain efficiency (Ali et al., 2023; Mocera et al., 2023). Economic performance is sensitive to annual utilisation, electricity tariffs, demand charges, charging efficiency, infrastructure sharing, and battery replacement. Utilisation of charging assets is critical: infrastructure shared across multiple machines can dramatically lower cost per productive output, whereas single-machine allocation increases capital intensity (Un-Noor et al., 2022; Bauer et al., 2025). Battery lifetime parameters (cycle count, depth of discharge, replacement cost) are particularly important in high-utilisation contexts and must be explicitly modelled for robust comparisons.

Hydrogen fuel-cell machinery entails high equipment cost and additional expenditure on storage, dispensing, compression, and refuelling infrastructure (IEA, 2024). Unlike BEVs, hydrogen infrastructure costs are less easily diluted through sharing, and the recurring cost of hydrogen fuel can dominate total cost of ownership. Electrolytic hydrogen is especially sensitive to electricity price, electrolyser utilisation, and conversion efficiency. Production route (electrolysis, steam-methane reforming, reforming with CCS) has a decisive effect on economic and environmental performance (IEA, 2024; Peppas et al., 2024). Discount rates also affect pathways asymmetrically: higher rates favour lower initial outlay (diesel); lower rates value future savings from BEVs or hydrogen.

Many techno-economic assessments (TEAs) in the literature report cost per machine or per operating hour, rather than per unit of productive output, which can obscure functional comparability when utilisation or productivity differ across pathways (Mocera et al., 2023; Bauer et al., 2025). The present study addresses this by adopting a relative-adjusted total cost of ownership (RA–TCO) expressed per tonne of material moved, fully aligned with the LCA functional unit.

2.3. Policy, infrastructure, and energy-supply conditions

The adoption of new NRMM technologies is strongly influenced by the regulatory, infrastructure, and energy-supply context (European Commission, 2016; ICCT, 2016; Transport & Environment, 2024b). In the EU, Stage V regulations control exhaust pollutants but do not set direct CO_2 limits for NRMM. Decarbonisation incentives therefore arise indirectly via carbon pricing, procurement, investment support, energy policy, fuel regulation, and infrastructure initiatives.

The Alternative Fuels Infrastructure Regulation (AFIR) establishes requirements for publicly accessible charging and hydrogen-refueling networks, notably along the TEN–T network and in urban nodes (European Commission, 2023a; AFIR, 2023). While these provisions primarily target road transport, they can enhance access for NRMM operating near industrial corridors, mines, and quarries. However, public network availability does not remove the need for dedicated, site-specific infrastructure, especially in confined or remote operations with shift-based energy demand.

Standardised hydrogen protocols (e.g., SAE J2601, J2601-2) improve technical predictability, but NRMM deployments must align storage pressure, daily demand, compressor capacity, and refueling windows to ensure operational feasibility (DOE, 2014; SAE International, 2014). Infrastructure existence alone does not guarantee high utilisation or economic viability.

The EU's framework for renewable fuels of non-biological origin (RFNBO) introduces additionality and temporal/geographical correlation requirements for qualifying hydrogen, with lifecycle GHG thresholds ensuring climate integrity (European Commission, 2023b,c). These stipulations mean that renewable hydrogen cannot simply be modelled as a zero-emission input—full energy sourcing and conversion chains must be represented.

Policy support – such as grants, subsidies, or carbon pricing – can significantly alter the competitiveness of pathways, but future support levels are uncertain and should be treated as scenario variables rather than permanent fixtures (Transport & Environment, 2024b; IEA, 2024). A lifecycle-consistent policy analysis must distinguish between tank-to-wheel and well-to-wheel accounting, and infrastructure allocation logic must reflect both demonstration and commercial deployment scenarios.

2.4. Nordic case-study rationale and transferability

The Nordic countries are frequently cited as leaders in low-carbon electricity, electrification policy, and industrial decarbonisation (International Energy Agency (IEA), 2023b). However, they are not homogeneous: Norway and Sweden benefit from particularly low grid intensities, Finland from a mixed portfolio including nuclear and renewables, while Denmark exhibits higher emissions from electricity generation. This variation enables a nuanced exploration of how regional electricity supply affects machinery performance.

The Nordic region is thus used as a best-case and policy testbed for NRMM decarbonisation. If battery-electric or electrolytic-hydrogen systems are not competitive under these favourable conditions, widespread adoption in more carbon-intensive or infrastructure-constrained regions is even less likely. However, cold-climate operation (prevalent in Nordic countries) introduces additional uncertainty, as low temperatures can increase auxiliary energy demand, affect charging and battery performance, and alter fuel-cell operation (Dai et al., 2022; IEA, 2024). The present study annualises machine performance, but recognises that detailed hourly simulation would be needed for full cold-climate analysis. Results from the Nordic case are therefore most transferable to regions with low-carbon electricity, predictable site-based operation, high utilisation, and access to appropriate infrastructure.

2.5. Research gap and contribution of the present study

The literature provides substantial evidence on individual aspects of NRMM decarbonisation, but not on their combined effect under a consistent, work-based framework. Four key limitations persist:

- First, most NRMM and quarry studies focus on environmental performance or alternative-fuel substitution, without jointly comparing country-specific electricity, work-normalised cost, infrastructure allocation, and policy context (Salman and Chen, 2013; Peppas et al., 2024).
- Second, broader LCAs demonstrate sensitivity to grid intensity and battery inventories, but typically are not parameterised for medium-sized wheel loaders in quarry applications (Lombardi et al., 2017; Koroma et al., 2022; Shafique and Luo, 2022; Naumann et al., 2024; Bauer et al., 2025).
- Third, TEA studies identify cost drivers but often report results per machine or hour, not per unit of productive work, limiting functional comparability (Mocera et al., 2023; Ali et al., 2023; Bauer et al., 2025).
- Fourth, infrastructure and policy are frequently treated as external factors rather than modelled components; tank-to-wheel versus well-to-wheel pricing, and shared versus dedicated infrastructure, are rarely analysed side-by-side (Transport & Environment, 2024b; IEA, 2024).

The present study addresses these limitations through an integrated, parameterised framework that combines:

- cradle-to-grave machinery LCA and cradle-to-use energy-carrier modelling;
- country-specific Nordic electricity and hydrogen pathway assumptions;
- a work-based functional unit for both environmental impacts and RA–TCO;

- explicit battery, fuel-cell, hydrogen-storage, and replacement assumptions;
- comparison of dedicated single-machine and shared fleet infrastructure;
- lifecycle-consistent carbon-cost and policy scenarios; and
- deterministic sensitivity and Monte Carlo uncertainty analysis.

The methodological contribution is not a new LCA or TEA method in isolation, but the integration of environmental, economic, operational, infrastructure, regional-energy, and policy dimensions on a common productive-work basis for a clearly bounded NRMM application. This enables identification of not only which pathway performs best under base-case conditions, but also which assumptions and deployment scenarios drive the robustness of those rankings.

3. Materials and methods

3.1. Study design and reporting framework

This study integrates Life Cycle Assessment (LCA) and Techno-Economic Assessment (TEA) to compare three propulsion pathways for a wheel loader operated under Nordic quarry duty: (i) diesel internal combustion engine (Diesel), (ii) battery-electric (BEV), and (iii) fuel-cell electric (FCEV). The LCA follows ISO 14040/44 principles and the ILCD Handbook structure (goal and scope definition, inventory analysis, impact assessment, and interpretation) (ISO, 2006; JRC, 2010).

Because published LCA results for electrified powertrains can vary materially with electricity-mix representation, battery inventory and replacement assumptions, and other methodological choices, we report all key parameterisations and scenario drivers transparently in the Supplementary Information and follow established guidance on LCA comparability and sensitivity reporting (Eltohamy et al., 2024). In line with the IPCC AR6 recommendation that transport and mobility options be compared on a lifecycle basis (rather than tailpipe-only), the comparative framing is explicitly lifecycle-consistent across both LCA and TEA (IPCC, 2022).

The TEA is formulated on a *work-aligned* basis using the relative-adjusted total cost of ownership (RA–TCO, €t^{-1} moved), ensuring functional equivalence between environmental and economic comparisons (Section 3.6). We also report the net present cost per operating hour (NPC, €h^{-1}) as an intermediate economic metric. Deterministic results are complemented with a stochastic (Monte Carlo) uncertainty module.

To preserve transparency while keeping the main manuscript concise, **all LCI tables, techno-economic inputs, carbon/credit schedules, and Monte Carlo distribution assumptions are reported in the Supplementary Information (SI)**. The SI is structured for direct traceability from the main equations and figures: (i) scenario logic and policy instruments (SI-1), (ii) functional unit and productivity parameters used for RA–TCO normalisation (SI-2), (iii) manufacturing and use-phase inventory tables (SI-3), and (iv) CAPEX/OPEX/infrastructure and replacement schedules (SI-5), with carbon/credit schedules (SI-6) and Monte Carlo distributions (SI-7).

Two deployment configurations are analysed:

1. **Single-machine scenario:** each machine bears a dedicated share of enabling site infrastructure.
2. **Fleet scenario:** infrastructure is shared across a representative fleet, reflecting common quarry and large-site operations where charging/refuelling assets are pooled. The allocation rule is documented in SI-5 (see Fig. 2).

3.2. Goal, scope, system boundary, and functional unit (LCA)

The goal of the study is to quantify the comparative life-cycle environmental performance of Diesel, BEV, and FCEV wheel-loader pathways under Nordic operating conditions and energy-sourcing constraints, generating decision-grade evidence for procurement, site-energy planning, and decarbonisation strategy.

The machinery system is modelled cradle-to-grave (materials and manufacturing, use/maintenance, and end-of-life). Energy carriers are modelled cradle-to-use, including upstream steps required to deliver usable energy to the machine (for example., power generation and distribution for electricity; hydrogen production and conditioning such as compression and dispensing). This boundary choice is necessary because upstream process energy can materially influence comparative results in heavy-duty applications (Peppas et al., 2024; Lombardi et al., 2017). Full inventory tables and process mappings are provided in SI-3.

One wheel loader delivering productive work under quarry duty, expressed as tonnes of material moved. Environmental results are reported per unit of productive output (for this case-study; kg CO_2-eq t^{-1} moved). Productivity parameters (payload and lifts per hour) used to compute throughput are reported in SI-2, and are used consistently in the TEA RA–TCO normalisation (see Fig. 3).

3.3. Hydrogen production, conditioning, and upstream electricity assumptions

This analysis evaluates three distinct hydrogen supply pathways for the fuel-cell electric wheel-loader configuration: renewable electrolytic hydrogen (FCEV_RE), steam methane reforming (FCEV_SMR), and steam methane reforming with carbon capture and storage (FCEV_SMR+CCS). These pathways are differentiated by production technology, upstream energy source, conversion efficiency, conditioning requirements, and well-to-wheel (WTW) greenhouse gas (GHG) intensity.

For FCEV_RE, total electricity demand encompasses both hydrogen production via electrolysis and downstream use for compression, storage, and dispensing. Country-specific electricity mixes are applied when electrolysis is grid-connected, reflecting the amplification of grid carbon intensity through electrolysis and hydrogen conditioning. Where applicable, a dedicated renewable-electricity scenario is modelled to comply with the EU's renewable fuel requirements (European Commission, 2023b). All lifecycle GHG accounting follows Delegated Regulation (EU) 2023/1185, including production, conditioning, distribution, and delivery to the machine (European Commission, 2023c).

For FCEV_SMR, hydrogen supply is modelled via fossil natural-gas reforming, with a WTW inventory that includes upstream gas supply, reforming energy, process emissions, and downstream compression, storage, and dispensing. The FCEV_SMR+CCS pathway builds on this, additionally modelling a specified CO_2 capture rate, capture energy demand, CO_2 transport and storage, and residual process and upstream emissions. The CCS pathway thus represents a lower-carbon, but not zero-emission, fossil hydrogen route.

Table 1 summarises the distinguishing assumptions for each pathway. All hydrogen-related energy requirements are included within the WTW boundary and are applied consistently in both LCA and carbon-cost calculations.

The pathway-specific well-to-wheel emission factor is calculated as:

$$EF^{\mathrm{WTW}}_{\mathrm{H_2},p} = EF_{\mathrm{prod},p} + E_{\mathrm{cond},p} EF_{\mathrm{el}} + EF_{\mathrm{dist},p}, \quad (1)$$

where $EF^{\mathrm{WTW}}_{\mathrm{H_2},p}$ is the delivered hydrogen emission factor for pathway p, $EF_{\mathrm{prod},p}$ represents production-stage emissions, $E_{\mathrm{cond},p}$ is the electricity required for compression, storage, and dispensing, EF_{el} is the electricity-mix emission factor, and $EF_{\mathrm{dist},p}$ captures transport and distribution emissions.

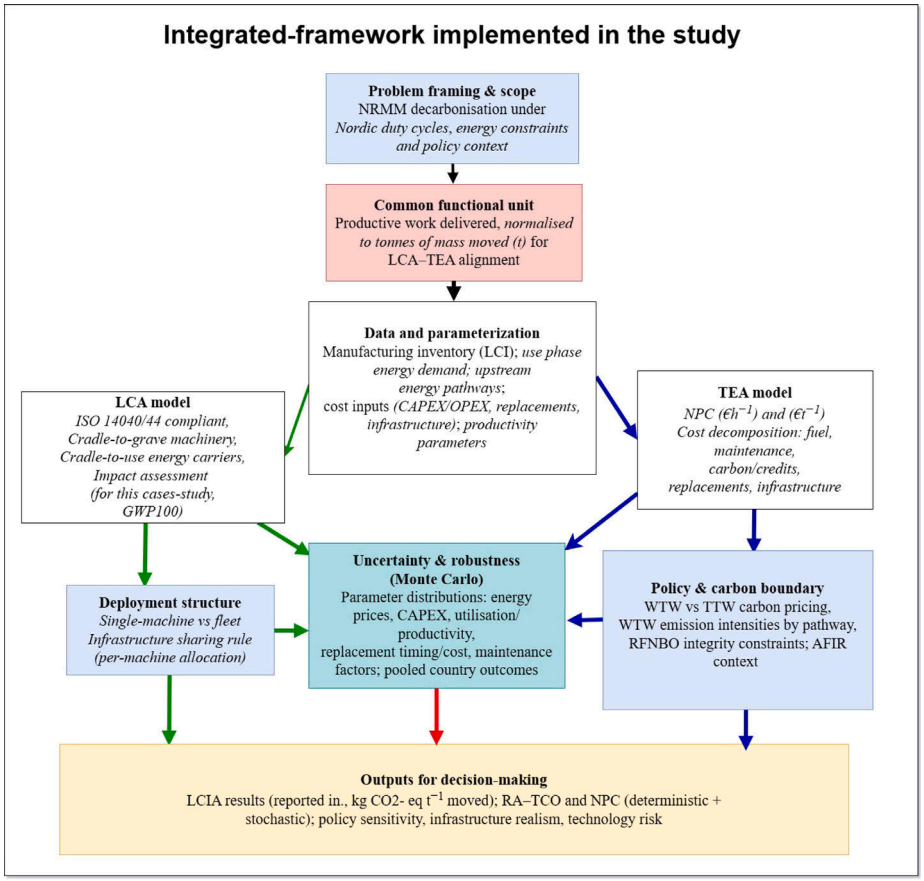


Fig. 2. Schematic diagram of the integrated framework implemented in this study. A common work-based functional unit aligns life-cycle environmental assessment with techno-economic modelling, while policy boundary conditions, infrastructure deployment structure, and uncertainty are treated as structural elements for decision-relevant comparison of diesel, battery-electric, and hydrogen pathways in NRMM.

Table 1
Hydrogen pathway assumptions: Production, conditioning, and upstream electricity.

Assumption / Pathway	Production route	Upstream energy	Conditioning & storage	WTW boundary
FCEV_RE	Water electrolysis	Grid/renewables	Electrolysis, compression, storage, dispensing	All stages (grid to use)
FCEV_SMR	Steam methane reforming	Natural gas	Compression, storage, dispensing	All stages (gas to use)
FCEV_SMR+CCS	SMR + CCS	Natural gas, capture energy	Compression, storage, dispensing	All stages; CO_2 capture/storage

For electrolytic hydrogen:

$$EF_{\mathrm{prod,RE}} = E_{\mathrm{electrolysis}} EF_{\mathrm{el}}, \quad (2)$$

where $E_{\mathrm{electrolysis}}$ is the electricity required to produce one kilogram of hydrogen.

Thus, the total electricity-related intensity for delivered electrolytic hydrogen is:

$$EF^{\mathrm{WTW}}_{\mathrm{H_2,RE}} = \left(E_{\mathrm{electrolysis}} + E_{\mathrm{compression}} + E_{\mathrm{storage}} + E_{\mathrm{dispensing}}\right) EF_{\mathrm{el}} + EF_{\mathrm{dist,RE}}. \quad (3)$$

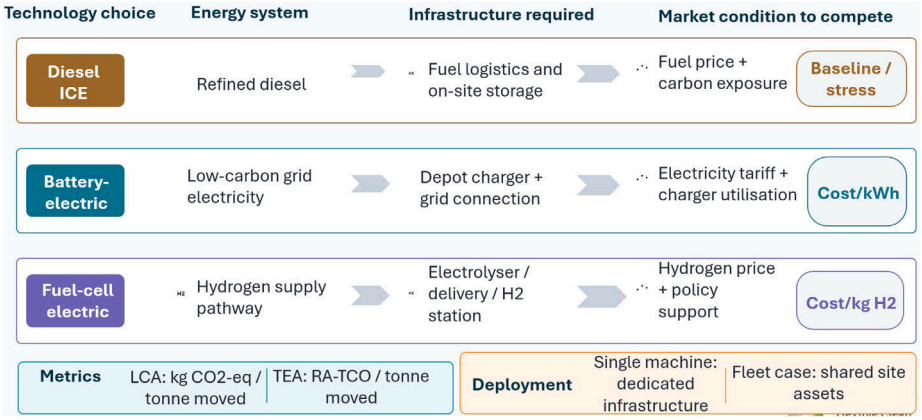


Fig. 3. System boundary and market-linked assessment framework for off-highway propulsion technologies. Conventional, battery-electric, and hydrogen pathways are evaluated within explicit energy-supply, infrastructure, and market-policy boundaries. The framework clarifies how technology performance interacts with grid carbon intensity, fuel prices, infrastructure utilisation, and policy instruments, enabling life-cycle-consistent comparison under real-world market conditions.

This formulation underscores the high sensitivity of renewable-electrolysis pathways to upstream electricity mix. As modelled, identical hydrogen demand results in markedly different lifecycle GHG emissions depending on whether Norwegian, Swedish, or Danish grid mixes are used as the electricity supply.

3.4. Case-study, duty-cycle, and productivity assumptions

The operational representation was developed from the quarry wheel-loader dataset reported by Peppas et al. (2024) and supplemented with explicitly stated modelling assumptions. To improve transparency, Table 2 summarises the principal parameters used to define machine productivity, annual utilisation, energy demand, lifetime workload, and fleet-level infrastructure allocation.

The parameters are classified according to their evidential status. *Literature-based parameters* are taken directly from the reference quarry dataset or published technical evidence. *Derived parameters* are calculated from literature-based inputs, including the fleet-weighted diesel consumption rate and tonnes moved per operating hour. *Model assumptions* are introduced to ensure functional equivalence between propulsion pathways. *Sensitivity parameters* are varied in the deterministic sensitivity and Monte Carlo analyses rather than treated as fixed measured values.

The distinction between the common productivity case and the fleet-anchor case is important. The common case provides a consistent basis for comparing lifetime environmental and economic performance, whereas the fleet-anchor case preserves the utilisation characteristics of the empirical quarry fleet when evaluating infrastructure sharing. The latter uses the median annual operating hours to avoid allowing a single highly utilised machine to dominate the representative-machine calculation.

For the fleet-anchor calculation, the representative diesel consumption rate is obtained as an operating-hours-weighted mean:

$$\dot{V}_{\mathrm{diesel,anchor}} = \frac{\sum_{i=1}^{n} H_i \dot{V}_i}{\sum_{i=1}^{n} H_i}, \tag{4}$$

where H_i is the annual operating time of loader i, $\dot{V}_i$ is its diesel consumption rate, and $n = 7$ is the number of medium-sized wheel loaders included in the fleet case. Applying the quarry dataset gives a representative diesel consumption rate of 25.31 $\mathrm{L\,h^{-1}}$.

Productive throughput for each propulsion pathway is calculated as:

$$TPH_t = m_{\mathrm{payload},t}\, n_{\mathrm{lifts}}, \tag{5}$$

where TPH_t is the productive throughput in $\mathrm{t\,h^{-1}}$, $m_{\mathrm{payload},t}$ is the modelled payload per lift, and n_{lifts} is the number of lifts completed per hour. These throughput values are applied consistently when normalising both life-cycle greenhouse-gas emissions and RA–TCO to tonnes of material moved.

Table 3 further identifies how each input category is treated in the assessment.

3.5. Policy boundary and lifecycle-consistent carbon pricing

Policy is implemented as a *jointly determined* component of the TEA to avoid inconsistent accounting that would otherwise penalise electricity and hydrogen pathways under tailpipe-only treatment. Two carbon accounting boundaries are supported:

- **Tank-to-wheel (TTW):** carbon costs applied only to direct combustion emissions (diesel tailpipe).
- **Well-to-wheel (WTW):** carbon costs applied consistently to upstream and use-phase emissions for all pathways (diesel WTT+TTW; grid electricity for BEV; hydrogen pathway intensity for FCEV).

The main results adopt WTW consistency to align economic signals with life-cycle impacts and to reflect that upstream emissions and conditioning steps can influence comparative outcomes (Peppas et al., 2024; Lombardi et al., 2017; Wang et al., 2020).

3.5.1. EU infrastructure and renewable-fuel integrity constraints.

Where scenarios are labelled as "renewable hydrogen" or "renewable e-fuel", the designation is treated as a *compliance condition* rather than a label. For EU-consistent renewable fuels of non-biological origin (RFNBOs), electricity-sourcing rules (additionality and temporal/geographical correlation) are aligned with Delegated Regulation

Table 2
Main case-study, duty-cycle, and productivity assumptions.

Parameter	Value used	Source and parameter status
Machine class	Medium-sized wheel loader, approximately 180–230 kW	Case-study definition based on the medium-loader subset reported by Peppas et al. (2024); literature-based.
Annual operating hours	1667 $h\,yr^{-1}$ in the common lifetime-productivity case; 1452 $h\,yr^{-1}$ for the fleet-anchor TEA case[a]	The common case is implied by the 15-year lifetime workload and hourly throughput. The fleet anchor is the median annual utilisation of the seven reference loaders; derived.
Payload per loading cycle	7.2 t for Diesel; 6.0 t for BEV and FCEV	Productivity-normalisation assumption retained from the implemented model; assumed.
Loading cycles	15 $lifts\,h^{-1}$ for all propulsion pathways	Common duty-cycle assumption applied to preserve a consistent operating pattern; assumed.
Productive throughput	108 $t\,h^{-1}$ for Diesel; 90 $t\,h^{-1}$ for BEV and FCEV[b]	Calculated as payload multiplied by lifts per hour; derived.
Diesel consumption	22–28 $L\,h^{-1}$ for the medium-loader class; fleet-weighted mean of 25.31 $L\,h^{-1}$	Individual loader data and medium-loader range from Peppas et al. (2024); fleet-weighted value calculated from 277,088.6 $L\,yr^{-1}$ over 10,949 $h\,yr^{-1}$; literature-based and derived.
BEV electricity demand	*36.3* $kWh\,h^{-1}$	Modelled from the mechanical-equivalent duty demand, drivetrain efficiency, and charging losses; model-derived.
FCEV hydrogen demand	*13* $kg\,H_2\,h^{-1}$	Modelled from the mechanical-equivalent duty demand, fuel-cell system efficiency, and hydrogen lower heating value; model-derived.
Assessment lifetime	15 years; approximately 25,000 operating hours under the common utilisation case	Lifetime assumption used consistently for LCA and TEA normalisation; assumed.
Lifetime productive workload	2,700,000 t moved for Diesel; 2,250,000 t moved for BEV and FCEV	Calculated from annual operating hours, pathway-specific throughput, and the 15-year assessment period; derived.
Fleet size used for infrastructure sharing	Seven medium-sized wheel loaders	Medium-loader subset selected from the reference quarry fleet reported by Peppas et al. (2024); literature-based case definition.
Infrastructure allocation	Per-machine infrastructure CAPEX = $C_{\mathrm{infra,site}}/7$	Shared charging or hydrogen-refuelling infrastructure allocated equally across the seven modelled machines; model assumption.

[a] The common lifetime-productivity case corresponds to $2,700,000/(15\times108) = 1667\ h\,yr^{-1}$ for Diesel and $2,250,000/(15\times90) = 1667\ h\,yr^{-1}$ for BEV and FCEV. For fleet-level TEA scaling, the annual-hours anchor is the median of the seven medium-loader observations: 862, 1336, 1436, 1452, 1655, 1659, and 2549 $h\,yr^{-1}$.
[b] Throughput is calculated as $TPH_t = m_{\mathrm{payload},t} \times n_{\mathrm{lifts}}$, where $m_{\mathrm{payload},t}$ is the payload per lift for technology t and n_{lifts} is the number of lifts completed per hour.

Table 3
Classification and treatment of operational model parameters.

Parameter category	Examples	Treatment in the model
Literature-based parameters	Annual operating hours of individual loaders, diesel consumption, machine power range, and reference fleet composition	Entered from published quarry operational data and retained as the empirical basis for fleet scaling.
Derived parameters	Fleet-weighted diesel consumption, median fleet-anchor hours, hourly throughput, annual tonnes moved, and lifetime workload	Calculated directly from literature-based or explicitly assumed parameters using the equations reported in the manuscript.
Assumed parameters	Payload by propulsion pathway, lifts per hour, project lifetime, functional equivalence, and equal infrastructure allocation	Fixed in the deterministic base case and reported explicitly to permit reproducibility and critical evaluation.
Sensitivity and Monte Carlo parameters	Annual utilisation, productivity, energy prices, machine CAPEX, maintenance, replacement costs and timing, and infrastructure-sharing factor	Varied within the ranges and probability distributions reported in the Supplementary Information; not interpreted as directly measured point values.

(EU) 2023/1184, and lifecycle GHG accounting and the minimum savings threshold are aligned with Delegated Regulation (EU) 2023/1185 (European Commission, 2023b,c). Hydrogen infrastructure access and utilisation risk is contextualised against the Alternative Fuels Infrastructure Regulation (AFIR) requirements for deployment and interoperability (European Commission, 2023a; AFIR, 2023). These policy instruments affect model assumptions through: (i) the admissible electricity basis for electrolytic hydrogen, (ii) the WTW emissions intensity used for carbon-costing, and (iii) the timing/availability interpretation for refuelling/charging infrastructure in deployment scenarios. Parameter values and scenario switches are reported in SI-1 and SI-5.

3.6. Techno-economic assessment: objective, metrics, and equations

The TEA compares pathways on a work-aligned basis using RA–TCO ($€\,t^{-1}$ moved), computed from NPC per hour ($€\,h^{-1}$) and effective productivity ($TPH_{c,t}$). For each country c and technology t:

Net present cost per operating hour (NPC).

$$NPC_{c,t} = \frac{\sum_{y=1}^{N} \frac{C_{c,t,y}}{(1+r)^y} - \frac{RV_{c,t}}{(1+r)^N}}{N \cdot H}, \tag{6}$$

where N is the project life (years), H is annual operating hours ($h\,yr^{-1}$), r is the discount rate, $C_{c,t,y}$ is total cost in year y, and $RV_{c,t}$ is residual value at end of life.

Annual cost is decomposed to match the Results cost-component figures:

$$C_{c,t,y} = C^{cap}_{c,t,y} + C^{fuel}_{c,t,y} + C^{maint}_{c,t,y} + C^{carbon}_{c,t,y} + C^{repl}_{c,t,y} - C^{credit}_{c,t,y}. \tag{7}$$

All component definitions, input values (CAPEX, OPEX, infrastructure shares, replacement intervals/costs, residual value) and country-specific parameter sets are reported in SI-4.

All net present cost calculations apply a real discount rate of $r = 7\%$, consistent with prior techno-economic assessments of heavy-duty and off-road machinery. A higher discount rate favours pathways

Table 4
Wheel loader fleet composition and operational data for the reference quarry.
Source: Reconstructed from Peppas et al. (2024), Table 2.

Wheel loader class	Units	Rated power (kW)	Fuel use ($L\,h^{-1}$)	Annual diesel ($L\,yr^{-1}$ per unit)
Small wheel loaders	4	90–120	12–15	18,000–24,000
Medium wheel loaders	7	180–230	22–28	40,000–52,000
Large wheel loaders	2	>300	35–45	60,000–75,000
Total fleet	**11**	–	–	~520,000

with lower upfront capital expenditure (diesel) and penalises capital-intensive options, particularly hydrogen fuel-cell systems with dedicated infrastructure, whereas a lower discount rate increases the weight of operating costs and improves the relative position of energy-efficient electrified pathways.

Relative-adjusted total cost of ownership (RA–TCO).

$$RA\text{-}TCO_{c,t} = \frac{NPC_{c,t}}{TPH_{c,t}}. \tag{8}$$

$TPH_{c,t}$ is computed from payload and lifts per hour (SI-2). This metric is the primary comparator because it links cost to delivered work rather than ownership time.

Carbon cost term under WTW.

$$C^{carbon}_{c,t,y} = \tau_{c,y} \cdot EF^{WTW}_{c,t} \cdot H, \tag{9}$$

where $\tau_{c,y}$ is the carbon price ($€\,tCO_2^{-1}$) and $EF^{WTW}_{c,t}$ is the WTW emission intensity ($tCO_2\,h^{-1}$). WTW emission intensity is derived from energy use (SI-2) and country-/pathway-specific upstream intensities (SI-3 and SI-5). Reporting both TTW and WTW cases (where relevant) makes the accounting boundary explicit and avoids tailpipe-only bias (IPCC, 2022; Peppas et al., 2024).

3.6.1. Fleet scenario scaling and quarry duty-cycle inputs (TEA)

To ensure that the fleet case reflects empirically reported quarry operations (Table 4), the TEA fleet scenario is parameterised using the wheel-loader operational dataset reported by Peppas et al. (2024). Table 5 lists the annual operating hours and diesel consumption rates ($L\,h^{-1}$) for the Medium/large wheel-loader fleet and the implied annual diesel throughput ($L\,yr^{-1}$). These fleet inputs are used to (i) characterise site-level energy demand and (ii) derive a representative "fleet-anchor" loader for work-normalised RA–TCO comparisons. All conversions from diesel throughput to pathway-specific energy demand (Diesel/BEV/FCEV) and the corresponding WTW emissions intensities are documented in the Supplementary Information (SI-2 and SI-3/SI-5).

Fleet scaling is implemented through two mechanisms.

- **Fleet-anchor loader (operational normalisation).** The fleet schedule is reduced to a representative annual operating-hours anchor, H^{anchor}, and a fleet-weighted diesel consumption rate, $\dot{V}^{\text{anchor}}$. In the implemented model, H^{anchor} is set to the *median* of the fleet operating-hours vector, while $\dot{V}^{\text{anchor}}$ is computed as an *hours-weighted mean* of diesel $L\,h^{-1}$ across the fleet:

$$\dot{V}^{\text{anchor}} = \frac{\sum_{i=1}^{n} H_i \dot{V}_i}{\sum_{i=1}^{n} H_i}, \tag{10}$$

  where H_i and $\dot{V}_i$ are the annual operating hours and diesel consumption rate of loader i, respectively. This preserves the fleet's aggregate fuel throughput while retaining a single representative loader for consistent RA–TCO normalisation.
- **Infrastructure sharing (CAPEX allocation).** Shared site infrastructure (charging and/or hydrogen refuelling assets) is allocated per machine by dividing total site infrastructure CAPEX by the number of wheel loaders in the quarry fleet ($n = 7$ in Table 5):

$$CAPEX^{\text{infra}}_{\text{per machine}} = \frac{CAPEX^{\text{infra}}_{\text{site}}}{n}. \tag{11}$$

This allocation rule is the defining structural difference between the *single-machine* and *fleet* deployment cases; all other techno-economic assumptions (discount rate, replacement logic, O&M structure, and policy switches) are unchanged. Infrastructure cost items and allocation parameters are reported in SI-5, and the diesel stress and credit instrument definitions are reported in SI-1 and SI-6.

3.7. Uncertainty analysis and scenario structure

Uncertainty was evaluated using 900 Monte Carlo iterations. In each iteration, the model sampled uncertain technical and economic inputs, including machine CAPEX, energy prices, maintenance costs, component replacement, productivity, and infrastructure utilisation. The sampled values were then propagated through the integrated LCA–TEA model to recalculate $NPC_{c,t}$ and $RA\text{–}TCO_{c,t}$ for each country c and technology t.

Input distributions and parameter bounds are reported in SI-7. Parameters were treated as independent unless a physical or accounting relationship required joint updating. For example, changes in energy consumption affected both operating cost and well-to-wheel emissions, while changes in productivity affected the work-normalised environmental and economic results.

The uncertainty analysis covered four Nordic countries, single-machine and shared-fleet deployment, two BEV battery-life cases, and three hydrogen-production pathways. Fig. 4 summarises the scenario architecture, uncertain inputs, and model outputs.

The width of the resulting distributions differs by technology. BEV uncertainty is driven mainly by electricity price, annual utilisation, battery replacement, and charging-infrastructure allocation. FCEV uncertainty is dominated by hydrogen price, refuelling-infrastructure utilisation, and fuel-cell replacement assumptions. Diesel uncertainty is influenced primarily by diesel price, fuel consumption, and carbon cost.

3.8. Reproducibility, data traceability, and SI linkage

All figures reported in Sections Section 4–5 are generated from a single-file, parameterised model implementation. To ensure auditability, the manuscript refers to SI tables for each data category: scenario set and instruments (SI-1), productivity normalisation for RA–TCO (SI-2), LCI tables and upstream intensities (SI-3), techno-economic inputs and replacements (SI-5), carbon/credit schedules (SI-6), and Monte Carlo distributions (SI-7). Additional NPC-focused figures are placed in SI-8 by design to keep the main narrative centred on RA–TCO while preserving traceability of underlying cost magnitudes.

Table 5
Wheel-loader fleet activity data used for quarry fleet parameterisation. Medium/large wheel loaders (WL1–WL7) are used for the TEA fleet scaling; small wheel loaders (WL8–WL11) are reported for completeness. Annual fuel is computed as (annual hours) × (fuel L h^{-1}).
Source: Table 2 in Peppas et al. (2024), "Environmental assessment of alternative fuels utilisation in heavy transport operations for extractive industries." Values reproduced and re-tabulated for clarity.

(a) Medium/large wheel loaders (used in TEA fleet scaling)

Wheel loader ID	Annual hours (h yr^{-1})	Fuel (L h^{-1})	Annual fuel (L yr^{-1})
WL1	2549	25.0	63 725.0
WL2	862	27.0	23 274.0
WL3	1659	27.6	45 788.4
WL4	1452	25.7	37 316.4
WL5	1336	24.3	32 464.8
WL6	1436	27.0	38 772.0
WL7	1655	21.6	35 748.0
Total (WL1–WL7)			**277 088.6**

(b) Small wheel loaders (reported for completeness; not used in TEA fleet scaling)

Wheel loader ID	Annual hours (h yr^{-1})	Fuel (L h^{-1})	Annual fuel (L yr^{-1})
WL8	3350	5.4	18 090.0
WL9	1770	4.6	8142.0
WL10	638	4.8	3062.4
WL11	3748	4.7	17 615.6
Total (WL8–WL11)			**46910.0**

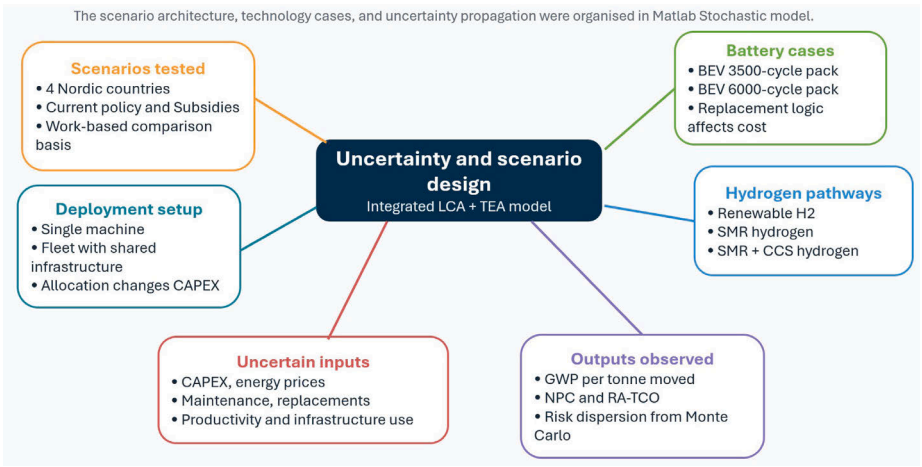


Fig. 4. Scenario structure, uncertain inputs, propulsion cases, and outputs evaluated in the 900-iteration Monte Carlo analysis.

4. Results

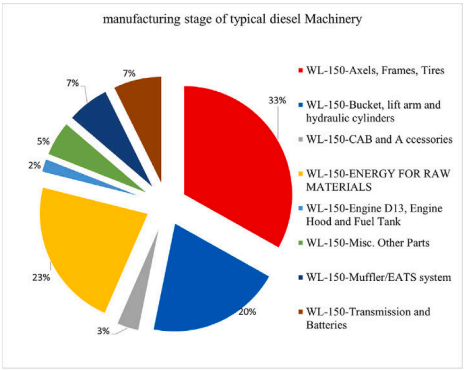
4.1. Life cycle impact assessment (LCIA)

4.1.1. Manufacturing-stage contributions and hotspots

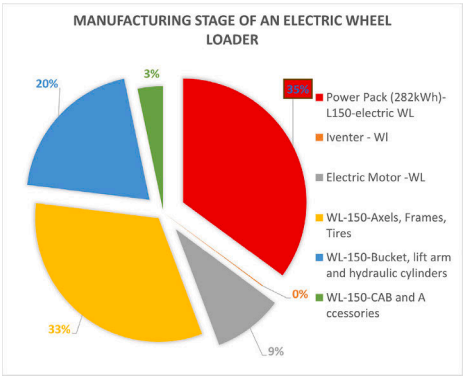
The manufacturing-stage results indicate that the three propulsion pathways are characterised by distinct upstream burden profiles. For the diesel wheel loader, manufacturing impacts are dominated by conventional ferrous materials and powertrain components. For the BEV pathway, manufacturing burdens shift towards battery cell production and associated active materials and current collectors, which can increase selected midpoint indicators even when use-phase GHG emissions fall under low-carbon electricity (Lombardi et al., 2017; Zhang et al., 2023; Paul et al., 2024; Salman and Chen, 2013). For the FCEV pathway, manufacturing burdens are concentrated in the fuel-cell stack and the high-pressure hydrogen storage system, where composite materials and balance-of-plant components can represent material-intensive contributions (Peppas et al., 2024). Fig. 5 reports the corresponding manufacturing-stage LCIA results for diesel (panel a), BEV (panel b), and FCEV (panel c), to contextualise the use-phase-driven results presented later and to maintain traceability to the life-cycle inventory tables archived in the Supplementary Information.

4.1.2. Nordic grid emission factors used in operational modelling

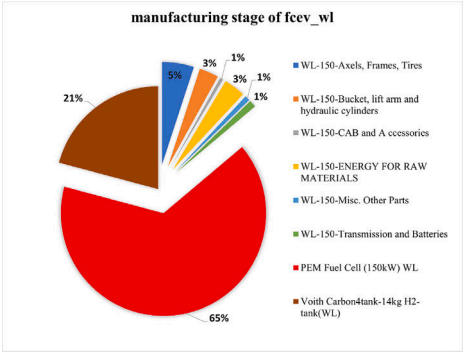
The life-cycle assessment uses country-specific electricity mixes to represent BEV charging electricity and, where applicable, electricity



(a) Diesel manufacturing impacts



(b) Battery-electric manufacturing hotspots



(c) Fuel-cell electric manufacturing impacts

Fig. 5. Manufacturing-stage LCIA results and hotspots for the diesel, battery-electric, and fuel-cell electric wheel-loader configurations.

inputs to upstream hydrogen production for renewable hydrogen pathways. This regionalisation is necessary because electrification benefits scale with grid carbon intensity and with upstream conditioning requirements (Lombardi et al., 2017; Koroma et al., 2022; Shafique and Luo, 2022; Naumann et al., 2024). The resulting grid emission factors therefore underpin the cross-country differences observed in the LCIA results.

Fig. 6 reports the SimaPro-derived life-cycle greenhouse-gas emission footprints of the national grid mixes (kg CO_2-eq kWh^{-1}). The factors spread more than an order of magnitude across the Nordics: Norway is lowest at 0.00738 kg CO_2-eq kWh^{-1}, Sweden is 0.02721 kg CO_2-eq kWh^{-1}, Finland (Fingrid mix) is 0.05111 kg CO_2-eq kWh^{-1}, and Denmark is highest at 0.21370 kg CO_2-eq kWh^{-1}. This ranking explains why BEV operational emissions remain very low in Norway/Sweden/Finland while increasing in Denmark, and why electricity-intensive hydrogen pathways can become upstream-emissions dominated under higher-carbon grids.

4.1.3. Emissions per unit of work delivered across nordic countries

Fig. 7 report the life-cycle greenhouse gas (GHG) emissions per unit of productive output (kg CO_2-eq t^{-1} moved) for diesel, battery-electric (BEV), and fuel-cell electric (FCEV) wheel loaders operating in Finland, Sweden, Norway, and Denmark. Results are normalised to a work-based functional unit rather than distance or time, which is more appropriate for non-road mobile machinery (NRMM) because payload, utilisation intensity, and duty severity dominate environmental performance (Spielmann et al., 2014; Wu et al., 2021).

Across all countries, diesel wheel loaders exhibit the highest life-cycle emissions, with the use phase accounting for the dominant share. Despite compliance with Stage V pollutant regulation, CO_2 emissions remain structurally coupled to fuel throughput and cannot be mitigated through after-treatment technologies alone. Consequently, diesel emissions vary only marginally across countries and form a relatively flat baseline in Fig. 7, confirming earlier NRMM LCAs that identify fuel combustion as the primary driver of climate impacts (Ebrahimi et al., 2020; ICCT, 2016).

Battery-electric wheel loaders show near-zero operational emissions in Finland, Sweden, and Norway, with Scope 2 contributions below approximately 0.06 kg CO_2-eq t^{-1}. This reflects the very low carbon intensity of Nordic electricity systems dominated by hydropower, nuclear, and wind generation (International Energy Agency (IEA), 2023a; European Environment Agency (EEA), 2024). When manufacturing emissions are included, BEV life-cycle impacts increase modestly (to approximately 0.04 kg CO_2-eq t^{-1}), but remain substantially below diesel. Overall, BEVs avoid approximately 1.2–1.3 kg CO_2-eq per tonne moved relative to diesel across the Nordic countries. These results confirm earlier LCAs showing that under low-carbon grids, electrification shifts emissions almost entirely to the manufacturing phase, which is rapidly amortised under high utilisation typical of quarry operations (Ellingsen et al., 2016; Bicer and Dincer, 2018; Wu et al., 2021).

Fuel-cell electric wheel loaders display a fundamentally different and strongly grid-dependent pattern. In Norway, where electricity used for hydrogen production is predominantly renewable, FCEVs reach life-cycle emissions of approximately 0.27 kg CO_2-eq t^{-1}, representing a reduction relative to diesel but remaining higher than BEV. In Denmark, however, the carbon intensity of grid electricity used for hydrogen production causes upstream emissions from electrolysis, compression, and distribution to dominate the life cycle. As a result, total FCEV emissions exceed the diesel reference by more than an order of magnitude, i.e., 54,000 t CO_2-eq over its lifetime (approximately 16× more than diesel scenario in Denmark) and are omitted from Fig. 7 to preserve readability. This illustrates the multiplicative amplification of upstream emissions in hydrogen supply chains when powered by carbon-intensive electricity (International Energy Agency (IEA), 2023a; Clean Hydrogen Joint Undertaking, 2024).

Manufacturing-stage contributions further reinforce this asymmetry. For BEVs, approximately 35% of embedded emissions originate

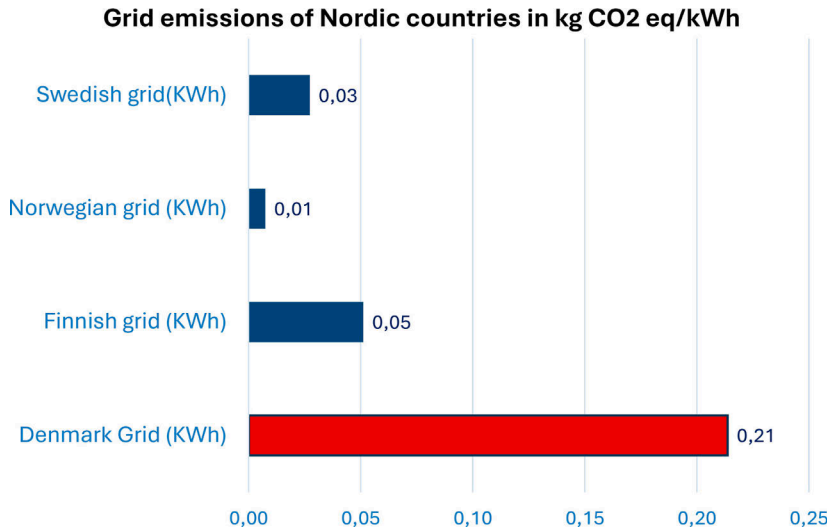


Fig. 6. Grid electricity emission factors used for country-specific modelling of BEV charging and (where applicable) renewable-hydrogen electrolysis electricity. Data and assumptions are documented in the Supplementary Information (SI-3.2).

from battery pack production, with the remainder distributed across conventional vehicle structures and power electronics. In contrast, FCEVs allocate roughly 65% of manufacturing emissions to the proton-exchange membrane (PEM) fuel-cell system and an additional ~20% to high-pressure carbon-fibre hydrogen storage. These components are both material- and energy-intensive, consistent with previous LCAs of hydrogen vehicles and equipment (Bicer and Dincer, 2018; Wang et al., 2020).

Overall, the results demonstrate that electrification delivers robust and predictable climate benefits under low-carbon electricity systems, while hydrogen pathways are highly sensitive to upstream energy supply. When hydrogen is produced using carbon-intensive electricity, FCEVs can perform worse than diesel on a life-cycle basis, underscoring the necessity of regionalised, pathway-specific assessment rather than technology-neutral assumptions.

4.2. Techno-economic assessment (RA–TCO and NPC)

4.2.1. Average RA–TCO across Nordic countries (current policy conditions)

Fig. 8 reports the average RA–TCO (in €t^{-1} moved) across Finland, Sweden, Norway, and Denmark under prevailing energy prices and existing carbon taxation, but without technology-specific investment subsidies or operational credits. Under diesel stress conditions (fuel prices plus CO_2 taxation), diesel wheel loaders exhibit the highest average RA–TCO of approximately 0.41€t^{-1} moved, with fuel costs dominating and carbon costs forming a material share. Once costs are normalised to delivered work, this structure reflects the coupling between fuel throughput and both operating expenditure and carbon exposure in combustion-based systems (European Commission, 2016; ICCT, 2016).

Both BEV configurations are cost-competitive without additional policy support in the Nordic context. BEV_3500C achieves an average RA-TCO of 0.32€t^{-1}, while BEV_6000C reaches 0.27€t^{-1}. Despite higher upfront CAPEX, BEVs benefit from high drivetrain efficiency and low carbon exposure when charged on low-carbon electricity, such that utilisation and electricity tariffs dominate competitiveness rather than capital cost alone (DOE/EPA, 2024; Lombardi et al., 2017). These findings align with earlier LCA–TEA studies on electric construction machinery, which consistently show that electricity cost and utilisation dominate BEV economics once diesel fuel and carbon costs are internalised (Caterpillar, 2024).

The difference between the two BEV cases reflects battery design trade-offs rather than energy cost. The 6000-cycle configuration incurs higher CAPEX but avoids a second battery replacement over the machine lifetime, whereas the 3500-cycle configuration relies on at least one replacement event. Importantly, the results show that cycle-based degradation modelling materially affects RA-TCO, confirming recent critiques of calendar-based battery lifetime assumptions in heavy-duty application (Caterpillar, 2024; Mocera et al., 2023).

In contrast, fuel-cell electric wheel loaders are not competitive without policy intervention. FCEV_RE reaches approximately 0.91 €t^{-1}, while FCEV_SMR and FCEV_SMR+CCS achieve 0.67 €t^{-1} and 0.73 €t^{-1}, respectively. In all hydrogen cases, fuel cost dominates RA-TCO, reflecting hydrogen prices of 4–7 €kg^{-1} even in relatively mature Nordic markets (IEA, 2024; European Commission, 2020, 2023d).This outcome is consistent with prior stochastic techno-economic assessments of hydrogen-powered off-road machinery, which identify hydrogen price volatility and infrastructure utilisation as the principal cost drivers (DOE/EPA, 2024).

4.2.2. Impact of policy instruments on RA–TCO

Fig. 9 illustrates the effect of policy instruments represented in the model (investment support for machinery and enabling infrastructure, operational credits for renewable hydrogen where applicable, and WTW-consistent carbon pricing). These instruments correspond to policy designs currently implemented or proposed in the Nordic region and the EU, such as Klimatklivet (Sweden), Enova (Norway), Business Finland support schemes, and EU hydrogen valley programmes. For

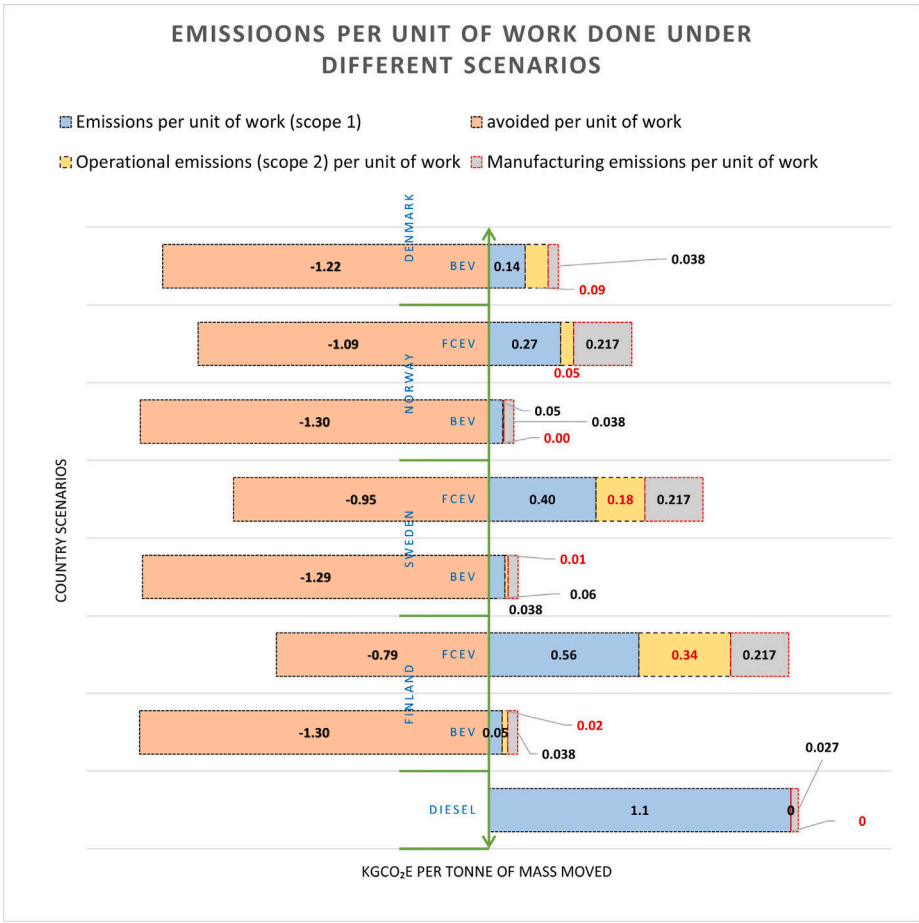


Fig. 7. Life-cycle greenhouse-gas emissions normalised to productive output (kg CO_2-eq t^{-1} moved) for Diesel, BEV and FCEV wheel loaders across Nordic countries.

battery-electric wheel loaders, policy support primarily reduces annualised capital cost, lowering RA-TCO to 0.23 € t^{-1} (BEV_3500C) and 0.26 € t^{-1} (BEV_6000C) if a replacement takes place in its lifetime. Electricity costs remain largely unchanged, reflecting the fact that Nordic policy frameworks predominantly target investment risk rather than operational electricity pricing. This confirms previous findings that BEV competitiveness is driven more by CAPEX de-risking than by energy subsidies in regions with low-carbon grids (Mocera et al., 2023). For hydrogen technologies, the absolute impact of policy instruments is larger. FCEV_RE RA-TCO decreases from 0.91 € t^{-1} to 0.67 € t^{-1}, while FCEV_SMR and FCEV_SMR+CCS converge around 0.65–0.66 € t^{-1}. The negative "credit" component visible in the RA-TCO breakdown reflects per-kilogram hydrogen support, consistent with hydrogen production and use incentives reported in Nordic hydrogen infrastructure roadmaps (HRS Norway, 2019; Muron et al., 2024; Clean Hydrogen Joint Undertaking, 2024). Nevertheless, even under policy support, hydrogen remains more expensive than BEV solutions. This reinforces the view, widely expressed in the literature, that hydrogen in construction equipment should be understood as a complementary option for operational niches where electrification is constrained by range, charging logistics, or peak power demands, rather than as a universal replacement for diesel (Reyes-Valenzuela et al., 2022). This outcome is consistent with prior stochastic techno-economic assessments of hydrogen-powered off-road machinery, which identify hydrogen price volatility and infrastructure utilisation as the principal cost drivers (IEA, 2024; European Commission, 2023d).

4.2.3. Uncertainty and technology risk (Monte Carlo)

Fig. 10 Monte-Carlo clouds pooled across the four Nordic countries, capturing uncertainty in CAPEX, energy prices, maintenance costs,

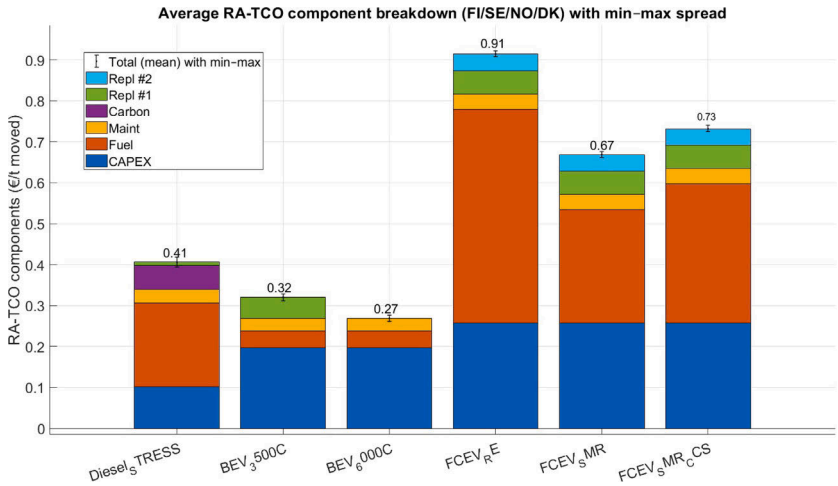


Fig. 8. Average relative-adjusted total cost of ownership (RA–TCO, € t^{-1} moved) across Finland, Sweden, Norway and Denmark under current policy conditions (no technology-specific investment subsidies or operational credits).

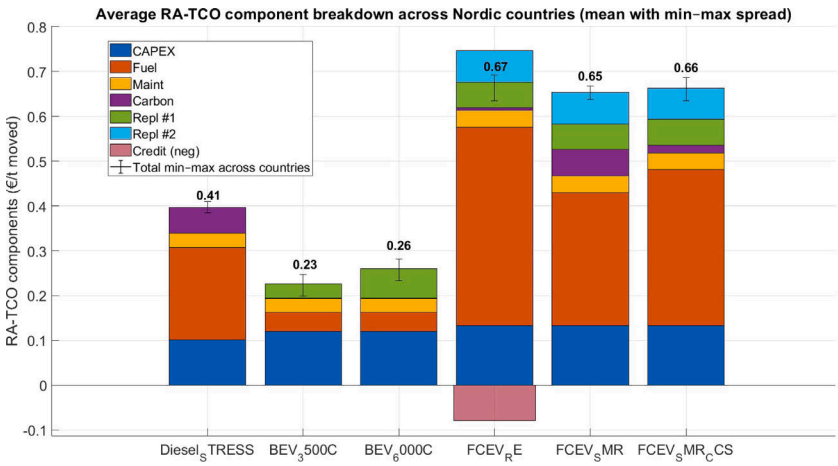


Fig. 9. Effect of policy instruments on RA–TCO (€ t^{-1} moved): investment subsidies, operational hydrogen credits, and WTW carbon pricing.

replacement timing, and productivity. Three robust patterns emerge. First, BEV solutions form tight clusters at low NPC (≈25–40 € h^{-1}) indicating low economic risk. This reflects the relative stability of electricity prices and predictable battery degradation compared with fossil and hydrogen fuels, consistent with prior uncertainty analyses (Reyes-Valenzuela et al., 2022). Second, hydrogen technologies exhibit wide dispersion (≈60–120 € h^{-1}), driven primarily by hydrogen price uncertainty and infrastructure utilisation risk. This confirms stochastic

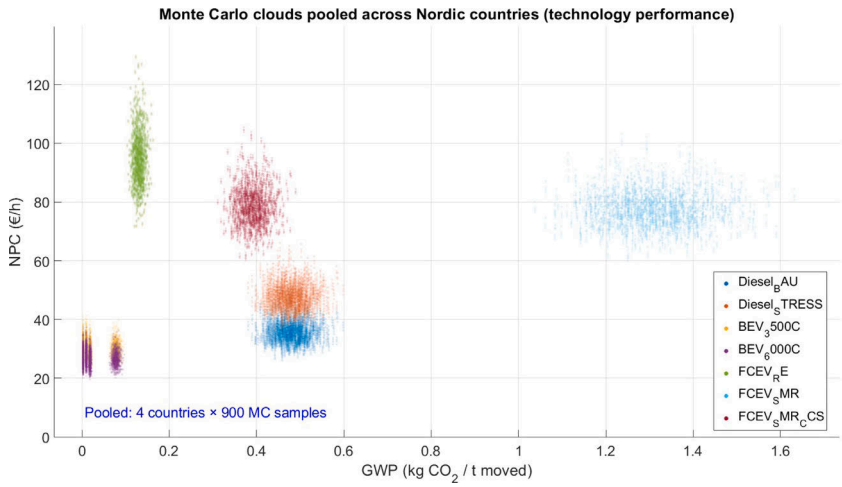


Fig. 10. Monte Carlo uncertainty results pooled across Nordic countries, showing dispersion of economic outcomes (NPC and/or RA–TCO) under parameter uncertainty in CAPEX, energy prices, maintenance, replacements and productivity.

Table 6
Average deviation between fleet and single-machine deployment scenarios under infrastructure sharing and applicable credits. Negative values indicate cost reductions under fleet deployment.

Technology	NPC deviation (%)	RA–TCO deviation (%)
BEV_3500C	−9 to −12	−8 to −11
BEV_6000C	−10 to −13	−9 to −12
FCEV_RE	−4 to −6	−3 to −5
Diesel (stress)	< − 2	< − 2

Notes: Fleet scenario assumes shared charging or refuelling infrastructure across 10 machines. BEV benefits are driven primarily by dilution of charger CAPEX, while FCEV benefits are limited by fuel-dominated cost structures. Full parameterisation and country-specific values are reported in Supplementary Information SI-4 and SI-7.

TEA findings that hydrogen-powered construction machinery entails significantly higher investment risk unless supported by long-term fuel contracts and guaranteed utilisation (IEA, 2024; European Commission, 2023d). Third, diesel under stress conditions overlaps with hydrogen (SMR+CCS) clusters, indicating that diesel machinery is no longer a low-risk baseline under plausible fuel and carbon price trajectories. This challenges the conventional perception of diesel as the "safe" option and aligns with recent policy-oriented assessments of NRMM decarbonisation risk (see Table 6).

5. Discussion

5.1. Structural drivers of competitiveness

The results demonstrate that the cost hierarchy observed in the Nordic wheel-loader market is not an artefact of parameter choice, but the outcome of three interacting structural mechanisms: (i) energy price formation and volatility, (ii) capital recovery under high utilisation, and (iii) exposure to life-cycle carbon pricing across the value chain.

Battery-electric wheel loaders emerge as economically dominant primarily because electricity prices in the Nordic region are both low and structurally stable, whereas diesel and hydrogen prices are not. This reflects the underlying generation structure of Nordic power systems, which are anchored by hydropower, nuclear and increasingly wind generation. As a result, marginal electricity costs are consistently below the delivered cost of imported fuels, even before accounting for carbon pricing.

Once machine utilisation is sufficiently high (approximately 1500 $h\,yr^{-1}$), battery capital costs are amortised rapidly, and total cost is governed by energy throughput rather than calendar lifetime. The cycle-based degradation representation used in this study therefore removes a structural bias present in earlier off-road TEA studies that rely on fixed calendar replacement assumptions. Empirically, this bias tends to overstate BEV costs in high-utilisation machinery by decoupling battery ageing from the actual work performed.

Hydrogen pathways are structurally constrained in a fundamentally different way. Even when hydrogen is produced via steam methane reforming (SMR), the delivered fuel cost per unit of useful energy remains higher than both electricity and diesel. For renewable hydrogen, electrolysis losses, compression, storage, distribution and refuelling collectively impose an irreversible energy and cost penalty. Critically, when hydrogen is produced using electricity from a carbon-intensive grid, these same losses amplify upstream emissions. In such cases, hydrogen is not merely "less clean" than BEVs; it can be environmentally inferior to diesel on a well-to-wheel basis, while simultaneously remaining more expensive. This dual penalty explains why, in both the LCIA and RA–TCO results, hydrogen supplied from high-carbon electricity pathways performs poorly on both environmental and economic metrics.

The results therefore reveal a technology asymmetry: electrification benefits from systemic cost compression (high end-use efficiency, low-carbon electricity and reduced maintenance), whereas hydrogen inherits systemic cost and emissions expansion when upstream electricity is carbon-intensive due to compounded conversion losses and infrastructure overheads. In this sense, hydrogen on a "bad grid" is not a transitional compromise but a structurally misaligned pathway.

5.2. Interpretation of policy instruments

Three policy instruments were evaluated in the model: (1) investment subsidies, (2) operational fuel credits, and (3) well-to-wheel (WTW) carbon pricing. Each operates on a different component of the cost structure and therefore produces asymmetric effects across technologies.

5.2.1. Investment subsidies

Machine and infrastructure subsidies primarily reduce annualised capital costs. This mechanism is highly effective for BEVs because capital expenditure constitutes a large share of their RA–TCO, particularly for batteries and charging infrastructure. For hydrogen, the same mechanism is materially less effective: capital subsidies reduce the cost of fuel-cell systems and refuelling infrastructure, but fuel remains the dominant cost driver, limiting the overall impact on RA–TCO. This asymmetry is consistent with deployment experience from Nordic low-emission construction and infrastructure projects, where BEV uptake accelerates rapidly once charging infrastructure is co-funded, while hydrogen deployment remains slower even under capital support (Stokke et al., 2022; Gustavsson et al., 2023; Transport for NSW, 2023).

5.2.2. Fuel credits

Operational fuel credits target the dominant cost component for FCEVs and therefore reduce RA–TCO more directly than capital subsidies alone. In the results, this effect appears as negative fuel-credit components for renewable hydrogen pathways. However, even under optimistic credit assumptions, renewable hydrogen remains cost-disadvantaged relative to BEVs, indicating that credits can narrow but not close the competitiveness gap under current cost structures.

Importantly, fuel credits do not eliminate the environmental penalty associated with hydrogen produced from carbon-intensive electricity. Where upstream electricity is not low-carbon, credits risk supporting pathways that are simultaneously expensive and high-emission, undermining climate integrity. This reinforces the need to condition "renewable hydrogen" claims on robust electricity-sourcing and lifecycle-accounting rules (European Commission, 2023b,c).

5.2.3. Carbon pricing

Applying carbon pricing on a WTW basis produces a non-linear response. Diesel and fossil hydrogen experience sharp cost increases under stress scenarios, while BEVs remain comparatively insensitive under Nordic electricity mixes. This creates a tipping effect in which diesel and hydrogen cost distributions can converge under high fuel and carbon-price trajectories, while BEVs separate clearly as a low-cost cluster.

The results also clarify that WTW-consistent carbon pricing is only environmentally effective when paired with low-carbon electricity. In grids with high emission factors, WTW carbon pricing exposes hydrogen to substantial penalties, confirming that hydrogen decarbonisation is conditional on upstream power-system decarbonisation.

5.3. Fleet deployment, infrastructure sharing, and technology risk

Appendix Figs. A.1–A.2 present Monte Carlo clouds comparing relative-adjusted total cost of ownership (RA–TCO) and life-cycle greenhouse-gas emissions (GWP) for electrified pathways against diesel reference cases under fleet-calibrated assumptions. These joint distributions provide insight not only into expected performance but also into the *risk structure* associated with each technology under realistic infrastructure sharing. Battery-electric wheel loaders form compact and well-separated clusters at low GWP and low RA–TCO across all Nordic countries. Even when uncertainty in electricity prices, battery replacement timing, and productivity is propagated, BEV solutions remain consistently below diesel reference clouds. This indicates that fleet deployment and shared charging infrastructure do not merely reduce average costs, but also compress outcome uncertainty, yielding a technology option that is both cost-competitive and low-risk. The tight clustering reflects the dominance of stable electricity prices, high drivetrain efficiency, and predictable degradation behaviour under high utilisation.

Diesel reference cases, particularly under stress conditions combining fuel price escalation and well-to-wheel carbon pricing, exhibit broader dispersion and partial overlap with hydrogen pathways. This demonstrates that diesel is no longer a low-risk baseline once exposure to fuel and carbon price volatility is internalised. Under these conditions, diesel investment risk converges towards that of transitional technologies rather than remaining a stable benchmark.

Fuel-cell electric wheel loaders display the widest dispersion in both cost and emissions outcomes. Renewable hydrogen pathways reduce GWP relative to diesel in favourable electricity systems, but remain economically volatile due to hydrogen price uncertainty and utilisation-sensitive refuelling infrastructure. Fossil-based hydrogen pathways (SMR and SMR+CCS) cluster at substantially higher GWP and RA–TCO values, confirming that hydrogen supplied from carbon-intensive grids can perform worse than diesel on a life-cycle basis. Fleet deployment moderates infrastructure-related costs for FCEVs, but the dominant contribution of fuel cost limits the extent of risk reduction compared with BEVs.

Overall, the Monte Carlo analysis confirms a structural asymmetry: fleet-level infrastructure sharing substantially improves both the mean performance and risk profile of battery-electric machinery, while hydrogen pathways remain exposed to upstream energy and market uncertainty. These findings reinforce that electrification is not only the lowest-cost pathway in Nordic contexts, but also the most predictable, whereas hydrogen should be reserved for operational niches where electrification is constrained and low-carbon hydrogen supply is contractually secured.

5.4. What the Monte Carlo uncertainty analysis reveals

The pooled Monte Carlo results show that the BEV cases have lower average RA–TCO and narrower cost distributions than the diesel and FCEV cases under the assumptions evaluated. Their dispersion is driven primarily by electricity prices, annual utilisation, battery replacement timing, productivity, and charging infrastructure allocation. The relatively narrow distributions indicate that these inputs produce less variation in the modelled BEV outcomes than the corresponding fuel-price and infrastructure inputs affecting the hydrogen pathways.

The FCEV distributions are wider due to uncertainty in hydrogen prices, hydrogen production pathways, refuelling infrastructure utilisation, machine CAPEX, and fuel-cell replacement. Renewable-hydrogen cases can approach lower-emission outcomes under favourable electricity conditions, but their economic results remain more variable than those of the BEV cases. The SMR and SMR+CCS cases are additionally affected by upstream natural-gas emissions, capture assumptions, and the treatment of residual lifecycle emissions.

Diesel results are influenced mainly by diesel price, fuel consumption, maintenance expenditure, and carbon cost. Under the stress scenarios, the resulting distributions broaden and partially overlap with some hydrogen cases, demonstrating that diesel does not necessarily provide a stable economic reference when fuel and carbon price uncertainty is included.

These results indicate that, for the medium-sized wheel loaders, Nordic energy conditions, and parameter ranges evaluated, BEV deployment provides the most favourable combination of expected cost, lifecycle greenhouse-gas performance, and modelled uncertainty. The conclusion is conditional rather than universal. Applications with substantially longer operating shifts, insufficient charging windows, weak grid connections, lower utilisation, or different energy prices may produce a different ranking and require site-specific assessment.

6. Conclusion

This study compared diesel, battery-electric, and hydrogen fuel-cell propulsion pathways for medium-sized wheel loaders operating under Nordic quarry conditions using an integrated life-cycle assessment and work-normalised techno-economic framework.

Under the electricity mixes, energy prices, utilisation levels, productivity assumptions, infrastructure configurations, and policy conditions represented in the model, the battery-electric cases achieved the lowest life-cycle greenhouse-gas emissions and RA–TCO. Their performance was supported by high drivetrain efficiency, relatively low-carbon Nordic electricity, and lower energy expenditure per tonne of material moved. Fleet-level charging-infrastructure sharing further improved their economic performance by distributing enabling-infrastructure CAPEX across several machines.

The hydrogen pathways produced more conditional outcomes. Renewable electrolytic hydrogen reduced life-cycle emissions relative to diesel where low-carbon electricity was available, but remained economically disadvantaged under the modelled hydrogen prices and infrastructure assumptions. Hydrogen produced using more carbon-intensive electricity could exceed diesel lifecycle emissions because electricity demand for electrolysis, compression, storage, and dispensing amplified upstream grid emissions. The SMR and SMR+CCS pathways were also affected by natural-gas supply, residual process emissions, capture performance, and hydrogen-conditioning requirements.

The integrated environmental and economic results therefore identify battery-electric propulsion as the most robust option among the pathways evaluated for this specific medium-sized wheel-loader application under Nordic quarry conditions. This conclusion does not establish a universal propulsion ranking for all NRMM. Hydrogen fuel-cell systems may remain relevant where operational requirements, charging constraints, grid limitations, or machine utilisation patterns reduce the feasibility of direct electrification, provided that low-carbon hydrogen supply and adequate infrastructure can be secured.

Policy instruments affected the magnitude of the cost differences but did not eliminate the importance of the underlying technical and energy-system conditions. Investment support improved the economics of capital-intensive equipment, carbon pricing increased the exposure of diesel operation, and hydrogen support reduced part of the renewable-hydrogen cost disadvantage. Nevertheless, technology selection should be based on site-specific assessment of duty cycle, electricity supply, infrastructure utilisation, energy prices, and lifecycle emissions rather than on propulsion labels alone.

The results are most applicable to medium-sized wheel loaders operating under duty cycles and energy conditions comparable to those modelled. Further research should incorporate measured temperature-dependent performance, transient quarry-duty profiles, site-specific charging and refuelling schedules, marginal electricity emissions, and empirical battery and fuel-cell degradation data before extending the conclusions to other machinery classes or regional contexts.

Limitations and future research

This study is subject to several limitations that should be considered when interpreting the results. The techno-economic assessment uses country-level average energy prices, grid-emission factors, and policy parameters to provide a consistent basis for comparison. These inputs do not fully represent site-specific grid-connection constraints, on-site generation, contractual electricity or hydrogen prices, charging windows, refuelling schedules, or local infrastructure utilisation. Consequently, both the absolute results and the relative ranking may change for individual projects. The conclusions should therefore be interpreted as conditional on the modelled Nordic quarry-duty and energy-system assumptions rather than as a universal technology ranking.

- The analysis focuses on medium-sized wheel loaders operating under Nordic quarry conditions; results may not be directly transferable to other NRMM classes or climatic and regulatory contexts.
- Fuel prices, electricity tariffs, and hydrogen costs are represented using contemporary averages and scenario projections; real-world site-specific contracts may lead to different economic outcomes.
- Battery and fuel-cell degradation are modelled using cycle- and hour-based replacement thresholds; future work should integrate physics-based ageing models and empirical field degradation data.
- Manufacturing inventories rely partly on secondary LCA databases and literature sources; primary supplier-specific data could refine embedded impact estimates.
- Grid electricity is treated using annual-average country mixes; hourly marginal emission factors and temporal correlation effects could further refine results.
- Infrastructure utilisation is represented using stylised fleet sizes; future studies should employ site-specific spatial–temporal infrastructure utilisation models.
- Future research should extend the framework to additional NRMM categories (examples given., excavators, haul trucks, tractors), incorporate dynamic technology learning curves (battery and fuel-cell cost trajectories), and explore integrated site-energy systems combining renewables, storage, and flexible demand.

CRediT authorship contribution statement

Anthony Katumwesigye: Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Jonas Spohr:** Writing – original draft, Visualization, Validation, Supervision, Methodology, Investigation, Conceptualization. **Magnus Hellström:** Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Resources, Methodology, Funding acquisition, Data curation, Conceptualization. **Reyn O'Born:** Writing – original draft, Visualization, Validation, Resources, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix. Supplementary Monte Carlo results

See Figs. A.1 and A.2.

Data availability

Data will be made available on request.

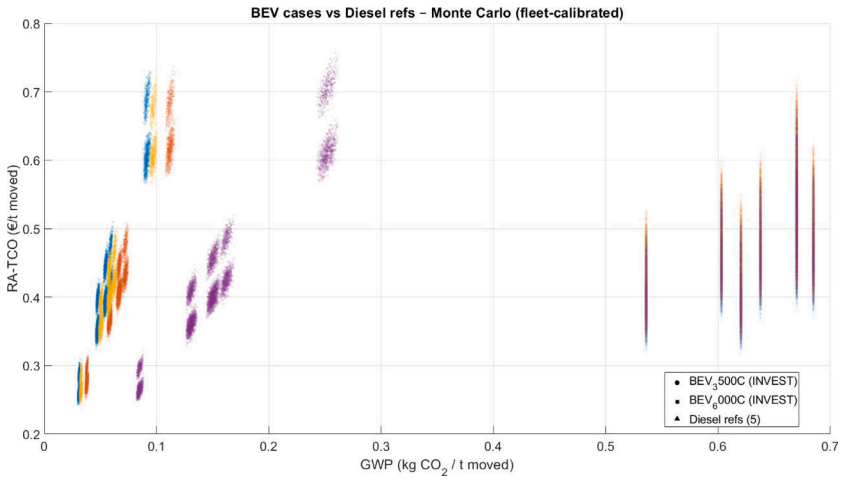

Fig. A.1. Monte Carlo clouds comparing BEV pathways against diesel references under fleet-calibrated assumptions. Each point represents one stochastic realisation across Nordic countries, showing the joint distribution of RA–TCO and GWP.

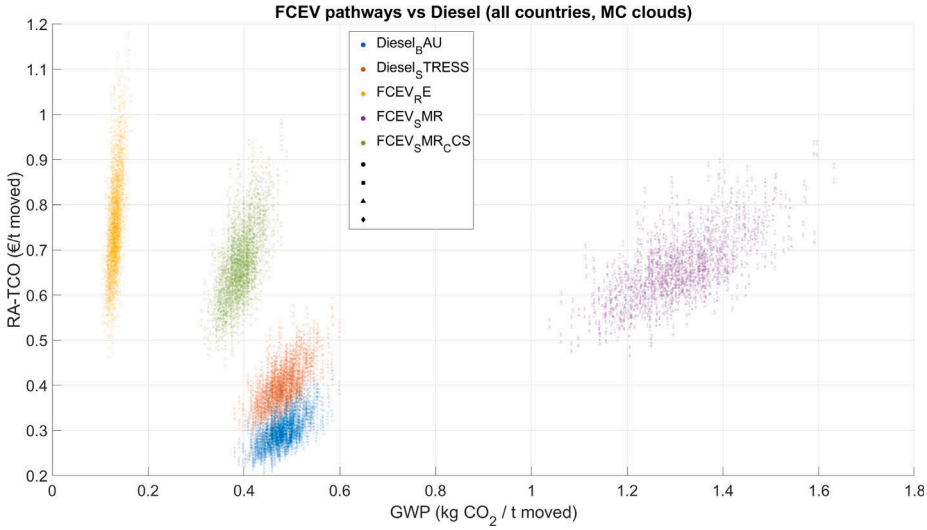

Fig. A.2. Monte Carlo clouds comparing hydrogen pathways (renewable, SMR, SMR+CCS) against diesel reference cases across all Nordic countries. Results illustrate the strong sensitivity of FCEV outcomes to upstream hydrogen supply and infrastructure utilisation.

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