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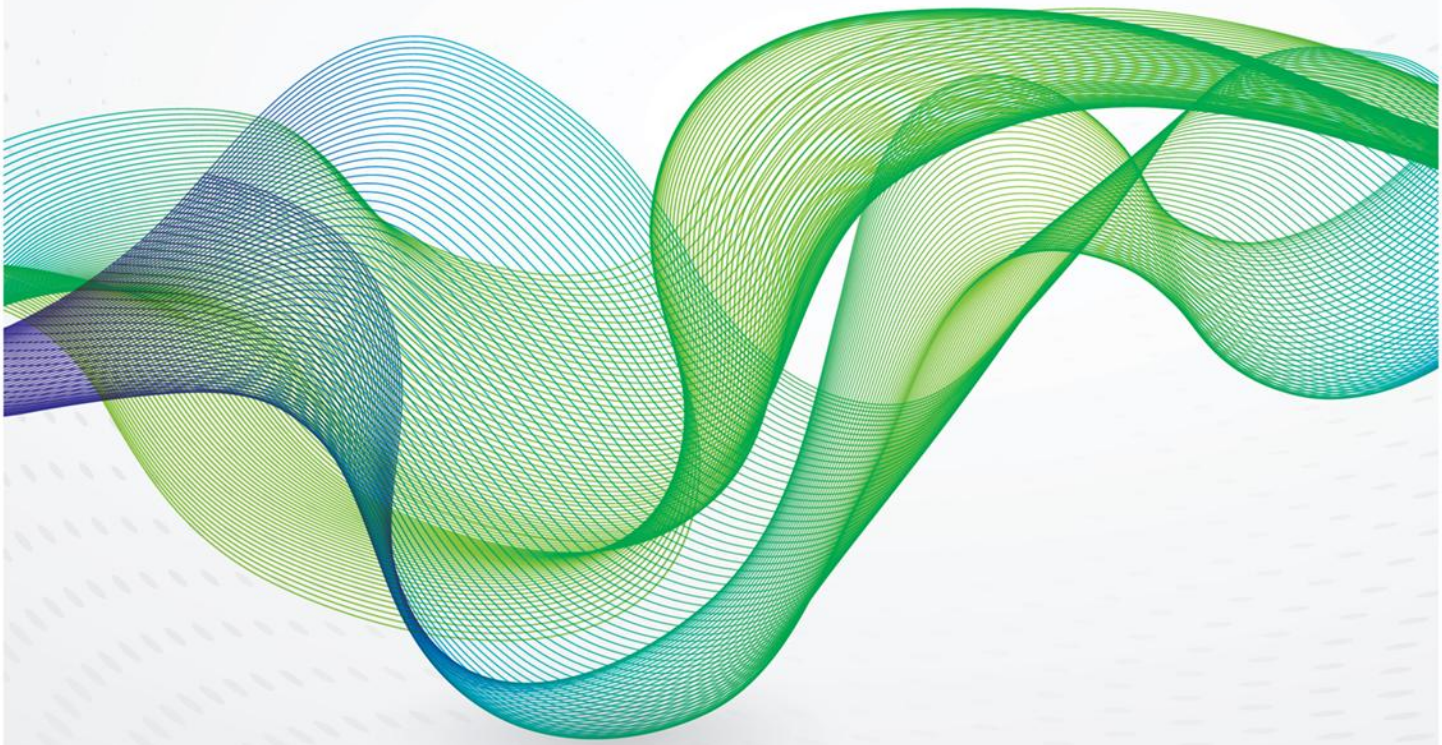
The Economics of Decarbonising Europe's Ammonia Industry: Policy, Pathways, and Trade-offs in a Hard-to-Abate Sector



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Abstract

Decarbonising ammonia production is a critical challenge in achieving Europe's climate targets, particularly given the sector's dependence on hydrogen derived from fossil fuels. This study conducts a comprehensive economic analysis of multiple hydrogen production pathways - Steam Methane Reforming (SMR), SMR with Carbon Capture and Storage (CCS), biomass gasification ($BIOH_2$), and electrolysis-based renewable hydrogen are assessed under the European regulatory framework, including the Renewable Energy Directive III (RED III), carbon intensity reduction targets (RFNBO for renewables, Low Carbon Fuels (LCF) for CCS, and RED III-Biofuels for $BIOH_2$), and the Carbon Border Adjustment Mechanism (CBAM). By evaluating Net Present Value (NPV) and emissions intensity across 52 existing ammonia production sites in Europe, this research identifies the most viable decarbonisation pathways for the medium term (2030-2040) while incorporating region-specific factors such as renewable energy potential, subsidy availability, and commodity costs.

The results highlight that under a Reference Case Scenario (RCS) without subsidies or carbon pricing, the existing SMR remains the most financially competitive option due to its high capital depreciation state and low operational costs. However, when policy mechanisms such as carbon pricing (via the EU ETS) and renewable hydrogen subsidies are introduced in the Policy-Supported Scenario (PSS), a notable shift occurs as renewable-based ammonia becomes more financially viable in regions with abundant renewable energy and low operating costs. Meanwhile, CCS and $BIOH_2$ fail to meet the emissions reduction thresholds required for certification as low-carbon under EU targets. As a result, they are ineligible for potential EU subsidies, which are currently reserved for renewable-based hydrogen—further limiting their adoption. Despite these policy-driven advantages, most low-carbon ammonia pathways struggle with negative NPVs, highlighting the need for more substantial financial incentives, greater regulatory flexibility, and increased infrastructure investment.

A key challenge identified in the study is the financial impact of hourly time-matching requirements for renewable electricity in hydrogen production. The results show that strict hourly matching, as mandated by RED III, significantly increases production costs due to excessive overinvestment in battery storage and oversized renewable generation. This cost penalty varies across regions, with countries possessing high and stable wind and solar resources experiencing a lower impact while those with high intermittency suffer extreme NPV reductions. A hybrid time-matching approach, where ammonia plants size their renewable capacity based on monthly matching while supplementing with grid electricity, emerges as a cost-effective alternative that maintains emissions reduction goals while improving financial feasibility.

The study also examines the potential for transatlantic ammonia trade under CBAM, carbon intensity reduction targets (RFNBO for renewables, LCF for CCS, and RED III-Biofuels for $BIOH_2$), and RED III constraints. It finds that US-produced ammonia from CCS, $BIOH_2$, and renewable hydrogen can meet the EU's stringent carbon intensity reduction thresholds, making it eligible for import under these regulatory frameworks. However, applying this report's carbon accounting methodology, only the top 10% of US-based CCS production would qualify for certification under the EU's CI LCF target. At the same time, $BIOH_2$ and renewables successfully meet their respective reduction thresholds. Economic modelling suggests that, by 2030, Imported US ammonia produced from $BIOH_2$ and CCS is already competitive with European ammonia, and by 2040, US renewable ammonia also becomes a viable alternative. This trend raises policy concerns regarding the competitiveness of European ammonia production, as lower-cost US imports could outcompete domestically subsidized renewable ammonia production due to inconsistencies in carbon accounting. Specifically, the potential exclusion of 50% of international shipping emissions from emissions calculations for imported ammonia may create an uneven competitive landscape, potentially distorting market dynamics.

Overall, while policy interventions such as subsidies and carbon pricing improve the financial viability of renewable ammonia, their effectiveness varies significantly across regions, necessitating a more flexible, region-specific approach. Also, flexible time-matching policies and cross-border hydrogen infrastructure could enhance cost-effectiveness without excessively relying on direct government financial support. As transatlantic ammonia trade grows, European policymakers must balance industrial resilience with international market competition. The findings provide crucial insights into the economic and policy trade-offs that will shape the future of ammonia production in Europe, offering evidence-based recommendations to guide industry stakeholders, governments and regulators in developing cost-effective decarbonisation strategies.

Executive summary

The decarbonisation of ammonia production is a key priority in Europe's transition towards a low-carbon economy. Ammonia production in 2023 accounted for approximately 485 million metric tons of CO_2 emissions annually, representing about 1.3% of global energy-related emissions [1]. Most ammonia production relies on fossil fuel-based Steam Methane Reforming (SMR) [1]. For comparison, the aviation sector contributes around 2.5% of global energy-related emissions, meaning ammonia production alone generates more than half the emissions of the entire aviation industry [2].

Under this context, this study provides a comprehensive economic analysis of four key hydrogen production pathways - SMR, SMR with Carbon Capture and Storage (CCS), Biomass Gasification ($BIOH_2$), and Renewable Electrolysis-based hydrogen - for ammonia synthesis across 52 fertiliser production sites in continental Europe, the UK, and Norway. Using net present value (NPV) calculations, emissions intensity assessments, and policy impact analyses, this research evaluates the economic feasibility of decarbonising Europe's ammonia industry. It identifies the most cost-effective pathways under different policy scenarios for the 2030–2040 period.

Economic Feasibility of Hydrogen-Based Ammonia Production

SMR Remains the Cheapest Option Without Policy Support
Under a Reference Case Scenario (RCS), where no subsidies or carbon prices are applied, SMR-based ammonia production remains the most financially viable option due to its low operating costs and limited reinvestment requirements. Across 52 ammonia plants, SMR maintains the highest NPVs, particularly in countries where infrastructure has already been mostly depreciated.

In contrast, low-carbon hydrogen-based ammonia pathways - including $BIOH_2$, CCS-based hydrogen, and renewable ammonia - exhibit significantly lower NPVs due to the high capital costs associated with new infrastructure investments. Renewable ammonia, the most capital-intensive option, is between 50% and 300% more expensive than SMR, even in regions with abundant renewable resources.

Carbon Pricing and Subsidies Change the Competitive Landscape
Under a Policy Support Scenario (PSS), where a carbon price of €68/tCO_2 in 2030 increases to €166/tCO_2 by 2050, the financial landscape changes significantly.

- A carbon price of $61.6/tCO2 (equivalent tax of approximately $1/kg of H_2) reduces the NPV of SMR-based ammonia by 102%.
- $BIOH_2$ faces the most significant impact, with an NPV reduction of 114% due to additional upstream carbon emissions penalties.

Conversely, renewable ammonia benefits significantly from targeted subsidies. Our analysis finds that a $1/kg H_2 subsidy improves the NPV of renewable ammonia by approximately 36% on a European average, helping to close the cost gap with fossil-based production. However, in high-energy-cost countries such as Germany and Austria, even subsidies do not fully bridge the financial gap due to the high costs of large-scale battery storage and oversized renewable generation.

Overcoming Investment Inertia for Green Ammonia Development
A significant challenge in ammonia decarbonisation is the delay in renewable hydrogen investments due to uncertain demand. The "chicken-or-egg" problem - where supply growth is hindered by weak demand signals and vice versa - creates investment inertia that slows deployment.

By 2040, cost reductions in electrolysers (30–50% CAPEX reduction), battery storage, and renewable energy deployment are expected to improve the competitiveness of renewable ammonia. However, these cost declines are not automatic and require early, decisive investment to unlock positive learning spillovers, cost reduction, and economies of scale. Without proactive policies and demand-side certainty, the low-carbon ammonia sector risks stagnation before reaching a cost-competitive tipping point.

Ultimately, early deployment of green ammonia should focus on regions with minimal subsidy requirements, ensuring the highest impact of initial investments while accelerating market adoption. These regions - such as Spain, Portugal, Bulgaria, and Poland - can serve as demonstration and case studies in the transition to a renewable-based ammonia industry.

The Cost of Time-Matching Requirements

Hourly Matching Increases Costs by up to 21 Times
The RED III mandate for hourly matching - which requires that renewable electricity for hydrogen production must be generated in the same hour it is used - has emerged as a significant financial burden for green ammonia projects.

- Moving from monthly to hourly matching halves the NPV of green ammonia in optimal locations (e.g., Bulgaria, Greece, and the UK).
- In worst-case locations (e.g., Slovakia, Romania, and Croatia), NPVs are reduced by up to 21 times due to massive overinvestment in battery storage and renewable capacity required under the hourly matching rule.

This extreme cost penalty makes hourly matching a more significant economic barrier than carbon pricing or even the lack of subsidies in many regions.

Hybrid Matching: A Cost-Effective Alternative
A hybrid matching approach, where ammonia plants size their renewable generation based on monthly matching while using the electricity grid to cover shortfalls, presents a cost-effective alternative to strict hourly matching. Unlike the current EU framework, which only permits grid supplementation if electricity is at least 90% clean, hybrid matching leverages differing national electricity decarbonization developments for 2030 and 2040 rather than imposing an EU-wide uniform threshold.

This approach serves as a no-cost policy instrument that reduces the need for excessive overbuilding of renewables and costly energy storage while enabling ammonia producers to integrate into evolving energy systems. Countries with ambitious plans for renewable expansion, nuclear deployment, or clean thermal technologies such as biomass or BECCS can leverage their projected grid mix to supply low-carbon electricity, significantly reducing the share of hours failing to meet clean power requirements under the current EU framework. In most cases, this method ensures full compliance with the national decarbonisation trend, while other countries see progressive improvements as their grids transition.

Moreover, hybrid matching is inherently temporary, as most European grids are expected to surpass 90% clean electricity beyond 2040 under the Fit for 55 package and the European Green Deal. As national grids become predominantly low-carbon, the need for flexible grid supplementation will diminish, naturally phasing out hybrid matching in favour of strict hourly compliance. By shifting from a rigid 90% requirement in 2030-40 to a system based on national decarbonization pathways, hybrid matching offers a pragmatic, temporary, and economically viable solution that accelerates renewable ammonia deployment in Europe without compromising long-term emissions goals of achieving deep decarbonisation by 2050.

Addressing Regional Disparities Through Pan-European Hydrogen Infrastructure
A critical challenge in scaling renewable ammonia production across Europe lies in the stark disparities in renewable resource availability and production costs between European countries. Our analysis highlights that at the existing SMR locations, nations such as Portugal, Greece, and Bulgaria benefit from abundant renewable energy and lower operating costs, positioning them as natural exporters of green hydrogen. In contrast, the existing SMR locations in countries like France, Slovakia, and Romania face higher capital expenditure (CAPEX) requirements due to weaker renewable availability, making local production less economically viable.

Developing a Pan-European hydrogen (H_2) pipeline infrastructure to bridge this gap presents a strategic opportunity. Such a network would enhance the feasibility of green ammonia production across the continent by facilitating the transportation of cost-competitive hydrogen from renewable-rich regions to energy-constrained markets. This approach would optimise resource utilisation and reduce the reliance on overbuilt renewable capacity and excessive energy storage investments in regions with suboptimal renewable conditions.

Transatlantic Ammonia Trade and CBAM

Our study finds that US-produced ammonia from CCS, $BIOH_2$, and renewable hydrogen can meet the stringent EU carbon intensity reduction thresholds, making it eligible for import under the related

regulatory frameworks outlined in this report. However, when applying this report's carbon accounting methodology—while still adhering to the EU CI target thresholds—only the top 10% of US-based CCS production qualifies for certification under the EU's CI LCF target, whereas $BIOH_2$ and renewables successfully meet their respective benchmarks.

By 2030, ammonia produced via $BIOH_2$ and CCS in the US is projected to be more cost-competitive than even depreciated SMR-based ammonia in Europe. By 2040, US renewable ammonia is expected to surpass European production in cost competitiveness due to declining electrolyzer costs and improved efficiencies.

Under the current EU Emissions Trading System (ETS) framework, which accounts for only 50% of emissions from international shipping, imported hydrogen can still bypass half of the emissions generated during transport. If the exporting country lacks carbon pricing on the remaining 50%, this creates the potential of a loophole, allowing imports to avoid full emissions accountability. Meanwhile, CBAM is designed to mirror the ETS but does not capture the remaining 50% of shipping emissions, as it falls outside its scope. This regulatory misalignment can potentially create a significant gap in emissions accountability.

With substantial financial support under the US Inflation Reduction Act (IRA), US ammonia imports could undercut European producers, even those relying on subsidised renewable hydrogen. If shipping emissions remain only partially covered under ETS and excluded from full capture, US ammonia may gain an unintended regulatory advantage, raising concerns over a potentially unbalanced competitive landscape.

Key Policy Recommendations

Adjust the Balance Between Carbon Pricing and Subsidies

- Current policies disproportionately penalise fossil-based ammonia while under-subsidising clean alternatives.
- A tiered subsidy system based on emissions reduction potential rather than binary support for renewables could only foster more significant innovation.

Support Learning and Experimentation by Investing in Cost-Effective Locations for Green Ammonia First

- The existing SMR locations in countries like Bulgaria, Spain, and Poland offer the highest financial feasibility for green ammonia production.
- The existing SMR plants with poor renewable potentials (e.g., some locations in Germany and Austria) may benefit from such early demonstration. These existing plants may need alternative incentives like CCS retrofitting rather than new electrolysis-based plants.

Relax Hourly Matching Requirements

- Hybrid matching approach reduces costs without significantly increasing emissions.
- Therefore, the 90% clean grid electricity requirement should be reconsidered to match each European country's national electricity market developments to encourage demonstration and deployment.

Strengthen the Competitiveness of European Ammonia Producers

- Clarify the treatment of shipping emissions under ETS and CBAM to ensure fair competition. Since ETS currently accounts for only 50% of international shipping emissions and CBAM does not cover the remaining portion, this regulatory gap could create an uneven playing field. Addressing this misalignment is crucial to maintaining a competitive environment for European ammonia producers.
- European ammonia producers may require additional trade adjustment measures to compete against overseas low-carbon ammonia with strong policy support (e.g., US imports under the IRA framework).

Conclusion

This study highlights the economic, regulatory, and trade-related complexities of ammonia decarbonisation in Europe. While carbon pricing and subsidies help shape financial viability, their effectiveness varies widely across regions, requiring more nuanced policy support and not a one-solution-fits-all approach.

A regionally adaptive policy framework - which considers location-specific renewable potential, existing infrastructure and associated constraints, and trade competition - will be crucial for a cost-effective transition.

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Nomenclature

Term	Definition
General Terms	
ATR	Autothermal Reforming
CAPEX	Capital Costs
CBAM	Carbon Border Adjustment Mechanism
CCfDs	Carbon Contracts for Difference
CfDs	Contracts for Difference
CH4	Methane
CI	Carbon Intensity
CLH	Chemical Looping Hydrogen
DCF	Discounted Cash Flow
EFOM	Energy Futures Optimization Model
ETS	Emissions Trading System
EU	The European Union
GHG	Greenhouse Gas
H2	Hydrogen
HB process	Haber Bosch process
IMO	International Maritime Organization
IPCEI	Important Projects of Common European Interest
IRA	Inflation Reduction Act
LCF	Low Carbon Fuels 70% CI reduction target compared to the fossil comparator
NH_3	Ammonia
OPEX	Operating Costs
RED III	The Renewable Energy Directive III
RED III-Biofuels	The Renewable Energy Directive III Biofuels 50% CI reduction target compared to the fossil comparator
RFNBO	Renewable Fuel of Non-Biological Origin renewable electrolytic 70% CI reduction target compared to the fossil comparator
SAMM	Spatial Analysis and Matching Module
SEC	Specific Energy Consumption
WACC	Weighted Average Cost of Capital
Pathways	
SMR	Steam Methane Reforming
CCS	Short form for SMR-CCS in the context of the pathways
$BIOH_2$	Woody biomass used in producing ammonia
Renewables	Ammonia production through solar, wind, and battery storage

1. Introduction

Ammonia production is one of the most carbon-intensive industrial processes globally, significantly contributing to greenhouse gas (GHG) emissions [3]. In Europe alone, the ammonia industry emits approximately 36 million metric tons of carbon dioxide annually, representing about 0.9% of the region's total GHG emissions and roughly 5% of industrial sector emissions [4]. Table 1 provides an example of the production capacity and emissions of some of Europe's major ammonia producers.

A concerning picture emerges when examining ammonia and other hard-to-abate segments within the industrial sector. Although ammonia, as part of the chemical sector, accounted for just 5% (450 $MtCO_2$) of total industrial emissions in 2020 – far less than steel's 29% (2.6 $GtCO_2$) and cement's 28% (2.5 $GtCO_2$) – Its energy and emissions intensity tell a different story. Ammonia production generates 2.4 tCO_2 per tonne, four times multiple of cement's 0.6 tCO_2/t and significantly higher than steel's 1.4 tCO_2/t. The same pattern is evident in energy consumption: while steel production requires 19 GJ/t and cement just 3 GJ/t, ammonia production demands a staggering 46 GJ/t, making it one of the most energy-intensive industrial processes [1].

Today, the Haber–Bosch process is the primary process of making ammonia; it synthesises ammonia by combining hydrogen and nitrogen under high pressure and temperature. Over 85% of this ammonia emission originates from hydrogen production via Steam Methane Reforming (SMR), which uses steam and a methane source, such as natural gas, to produce hydrogen [5]. This dependency on natural gas – both as a feedstock and an energy source – results in aforementioned emissions of 2.4 tons of CO_2 per ton of ammonia produced, underlining the urgent need for decarbonisation of existing production [1], [6], [7], [8].

Table 1: Ammonia production and greenhouse gas emissions of select countries in Europe

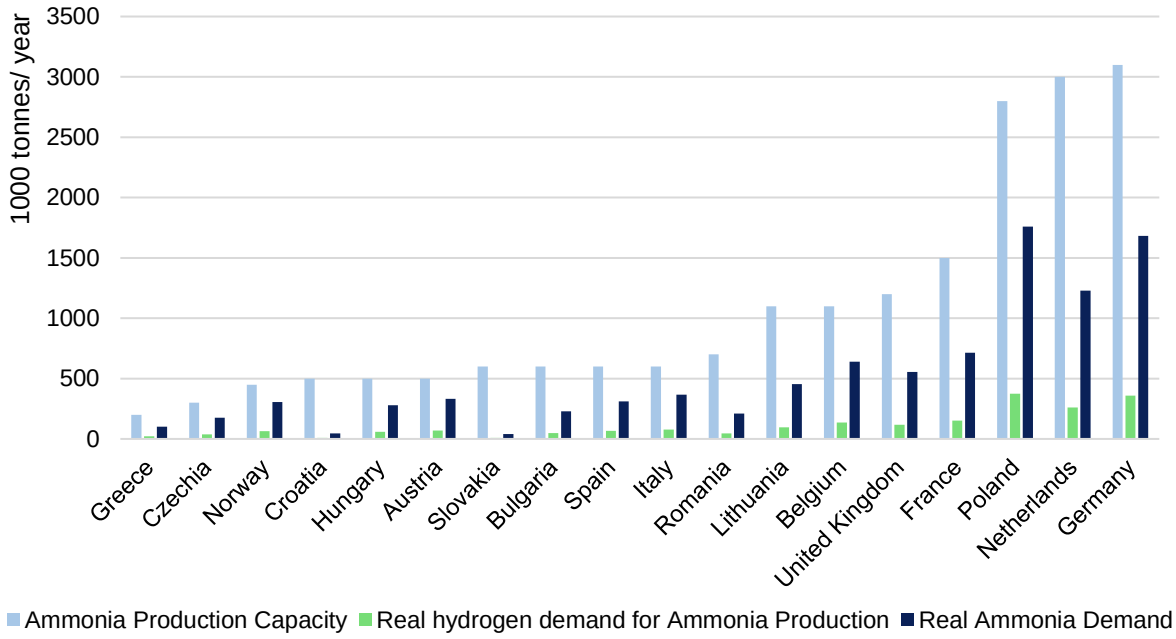
Country	NH3 Production (Mt)	Of Europe's Total Production[1] (%)	GHG Emissions from NH3 Production ($MtCO_2$-eq)[2]
Germany	3.1	15.2%	5.6
Netherlands	3.0	14.7%	5.4
Poland	2.8	13.7%	5.0
Norway	0.5	2.2%	0.9

Source: [8], [9]

Ammonia's decarbonisation is crucial for mitigating climate change, enhancing energy security and stabilising food systems. As a cornerstone of Europe's chemical industry, ammonia production is pivotal in agricultural productivity, with fertiliser production being its primary application. However, this sector remains among the most energy-intensive and carbon-emitting industries, accounting for 27% of the total verified emissions from the European Union's (EU) Emissions Trading System (ETS) for the chemical sector in 2019 [4]. Despite producing 14.7 million tonnes of ammonia in 2019, Europe's domestic output fell short of the 17.1 million tonnes demand, primarily due to cost-competitive imports from Russia, Algeria, Trinidad & Tobago, and Ukraine [10]. Geopolitical dependencies and energy price volatility, especially during the 2021-23 energy crisis, have underscored the urgency of diversifying and decarbonising ammonia production to stabilise supply chains [11]. As an example, the authors estimate based on available data that only 50%[3] of the production capacity of ammonia was used in 2022 [8], [13], while imports accounted for 15% of total ammonia demand [14], the split of which can be seen in Figure 1.

[1] European countries listed within [8]
[2] According to a conversion factor of 1.8 tCO_2/tNH_3 for conventional ammonia production [8]
[3] Based on the conversion factor of 4.7 tNH_3/tH_2 [12]

Figure 1: 2022 production capacity of ammonia in Europe



Source: Adapted from data within [8], [13]

Recognising hydrogen as central to its decarbonisation strategy, the EU aspires to expand electrolyser capacity fifty-fold by 2030, designating ammonia plants as key users of green hydrogen [5]. The Renewable Energy Directive III (RED III) introduces stringent criteria for renewable hydrogen production, mandating temporal and geographical correlation with additional renewable energy sources to ensure environmental integrity [15]. However, transitioning to low-carbon hydrogen pathways, such as renewables, biomass, or natural gas utilising carbon capture and storage (SMR-CCS), remains challenging. Renewable-powered electrolysis offers significant emission reductions but is hindered by the availability of renewables, high capex and opex, while biomass and SMR-CCS face scalability and infrastructure readiness issues [1], [7], [16].

Despite the European ammonia industry being among the most energy-efficient globally, with average emissions of 1.7 tons of CO_2 per ton of ammonia, reliance on fossil fuels constrains further decarbonisation through efficiency improvements alone [17]. Specific Energy Consumption (SEC) values, ranging from 28 to 37.5 GJ per ton of ammonia, reflect regional variations in energy efficiency [18]. Concentrated in regions with robust natural gas infrastructure, such as Germany, the UK, and the Netherlands, existing ammonia production depends heavily on natural gas, exposing the sector to geopolitical and economic vulnerabilities.

Beyond fertiliser production, ammonia is emerging as a versatile energy carrier and storage medium. So-called green ammonia, or ammonia produced using hydrogen from renewable electricity, can decarbonise maritime shipping as a zero-carbon fuel, aligning with International Maritime Organization (IMO) regulations [19]. Additionally, ammonia's integration into Power-to-X systems enables the conversion of surplus renewable electricity into storable energy forms, addressing intermittency challenges in renewable energy. Ammonia cracking technologies, which release hydrogen from ammonia, further enhance its applicability in hydrogen fuel cells and industrial decarbonisation, making it a cornerstone of a potential circular hydrogen economy [8].

Decarbonising the ammonia sector is essential for achieving the EU's climate goals, including net-zero emissions by 2050 under the European Green Deal [3]. However, balancing environmental objectives with economic competitiveness is imperative, as high production costs in Europe have historically driven ammonia imports from regions with cheaper energy resources [20]. The 2021–23 energy crisis, which saw a 40% decline in German ammonia production and increased imports to stabilise fertiliser output, exemplifies the sector's vulnerability to energy price fluctuations [11].

This study addresses gaps in the literature on sustainable ammonia production in Europe for the medium term (2030–2040) by focusing on four pathways: SMR, SMR with CCS, biomass-based ammonia, and ammonia produced from renewable sources. It evaluates each pathway's economic and environmental competitiveness, examining policy mechanisms, market forces, and technological developments that can accelerate decarbonisation while supporting broader economic and energy security objectives. The analysis considers how policy and regulatory frameworks like RED III intersect with green hydrogen adoption and the impact of different temporal matching rules (hourly, monthly, and hybrid). Additionally, it examines the potential competitiveness of importing ammonia from the United States into Europe constrained by Carbon Border Adjustment Mechanism (CBAM) regulations. The rest of this paper is structured as follows. Section 2 outlines the research background, while Section 3 discusses literature review. Section 4 then discusses the research methodology. Results and analysis are provided in Section 5. Section 6 outlines the implications for business and policy. Conclusions are offered in Section 7.

2. Europe's Hydrogen and Ammonia Decarbonisation Policies

This section establishes the context for the identified ammonia decarbonisation policies in the EU, UK, and Norway (refer to Table 2 for an overview of the identified European country policies). It opens by reviewing key hydrogen and ammonia policies, including RED III and various national strategies. Subsequent subsections discuss emerging decarbonisation approaches – such as SMR with CCS and renewable-based electrolysis – alongside examining economic and geopolitical factors, including the influence of energy prices and the role of carbon pricing mechanisms like CBAM.

2.1 EU-wide Policies

The EU has implemented comprehensive policies to mitigate greenhouse gas emissions across various industries. In the context of hydrogen and ammonia production, the EU has established a framework to promote sustainable practices and reduce carbon footprints.

The decarbonising ammonia industry requires the adoption of alternative hydrogen production pathways to replace conventional SMR. Autothermal Reforming (ATR) combined with CCS has emerged as one of the more economically viable options for reducing emissions. ATR integrates partial oxidation and steam reforming within a single reactor, simplifying the process while capturing and storing CO_2 emissions. SMR with CCS is another viable pathway, retrofitting the conventional process with CO_2 capture technologies to reduce emissions by up to 95%. Methane pyrolysis, which decomposes methane into hydrogen and solid carbon, offers a promising alternative. This process avoids CO_2 emissions altogether, provided the solid carbon can be monetised effectively, making it competitive with Carbon Capture and Storage (CCS) options [21].

While these methods represent near-term solutions, electrolysers powered by renewable electricity are considered the most sustainable long-term option. Electrolysis involves splitting water into hydrogen and oxygen, using hydrogen as feedstock for ammonia synthesis. However, its economic viability depends on reducing the capital costs of electrolysers and securing access to low-cost renewable electricity [7]. Other decarbonisation options, such as biomass gasification and biomethane substitution, are technically feasible but face challenges related to high costs and the complexities and sustainability of biomass supply chains and infrastructure development.

In our modelling, we have chosen to focus on SMR with CCS due to its current technological maturity and the existing infrastructure that supports its implementation. SMR is a well-established method for hydrogen production, and integrating CCS allows for significant reductions in carbon emissions, making it a viable option for large-scale applications in the near term [22].

Additionally, we have included woody biomass gasification in our modelling to explore its potential as a renewable hydrogen production pathway. Biomass gasification is a mature technology that uses a controlled process involving heat, steam, and oxygen to convert biomass into hydrogen and other products without combustion. This method offers the advantage of utilising renewable feedstocks and has the potential, if coupled with CCS, to lead to negative carbon emissions [23].

The European ammonia industry also explores cutting-edge innovations such as chemical looping hydrogen (CLH). CLH offers high-purity hydrogen and nitrogen streams while integrating CO_2 capture, reducing emissions by over 85% compared to SMR. However, trade-offs in water use and soil emissions highlight the importance of holistic environmental assessments when implementing these technologies [7].

High natural gas prices present a significant challenge to Europe's decarbonisation efforts. With natural gas prices in Europe being significantly higher than those in major ammonia-producing regions such as Russia, the US and the Middle East, domestic production has faced economic pressure. To remain competitive, European producers must adopt cost-effective decarbonisation strategies supported by regulatory measures like CBAM. The policy framework seeks to create a level playing field by imposing a carbon price on imports, encouraging the adoption of cleaner technologies in non-European countries willing to export to the EU market [21].

Moreover, implementing a uniform carbon price across regions would further incentivise sustainable ammonia production globally. However, the feasibility of decarbonisation strategies remains closely tied to the energy sector's geopolitical and market dynamics. The most recent example is the impact of the Russia-Ukraine war, which drastically altered natural gas supply chains and introduced additional uncertainties not accounted for in earlier analyses. The EU, UK, and Norway have implemented various regulations and support mechanisms to promote developing and deploying hydrogen and ammonia technologies, focusing on renewable energy, carbon capture, and low-carbon pathways, as shown in Table 2.

The EU's RED III provides an ambitious framework to accelerate the transition to renewable energy sources and decarbonise industrial sectors, including ammonia production. Building on the earlier RED II, RED III raises the target for renewable energy consumption to at least 42.5% by 2030, with an aspirational goal of 45% under the REPowerEU plan. These targets are aligned with the EU's climate neutrality objective by 2050 and intermediate goals of a 55% reduction in GHG emissions by 2030 compared to 1990 levels [15].

Renewable hydrogen, categorised as a Renewable Fuel of Non-Biological Origin (RFNBO), is central to achieving these objectives. RED III defines stringent criteria for hydrogen to qualify as renewable, including additionality (demonstrating new renewable energy sources), temporal correlation (synchronising hydrogen production with renewable electricity generation at monthly granularity until 2030 and hourly granularity thereafter), and geographic correlation (locating hydrogen production near renewable energy facilities). These rules ensure that green hydrogen and derivatives like green ammonia are sustainable and contribute directly to reducing emissions. The directive also extends these criteria to imported renewable hydrogen and ammonia, reinforcing the EU's commitment to global sustainability standards [24].

According to the European Commission's RED III, by 2030, 42% of hydrogen used in the industrial sector must be RFNBOs, increasing to 60% by 2035 [15]. RED III also introduces sectoral quotas to stimulate the adoption of renewable hydrogen. By mandating its use in hard-to-abate sectors, including industrial processes and transport, the directive indirectly promotes demand for green ammonia. For instance, ammonia's potential as a maritime fuel aligns with the EU's broader decarbonisation strategies, such as the FuelEU Maritime regulation [25]. This regulation, part of the EU's "Fit for 55" package, aims to reduce the greenhouse gas intensity of maritime fuels by setting incremental targets, starting with a 2% reduction by 2025 and reaching 80% by 2050, relative to the base year of 2020 [26]. It promotes the adoption of renewable and low-carbon fuels, including ammonia, to achieve these goals. Similarly, its application in sustainable aviation fuel production ties in with the ReFuelEU Aviation regulation, which sets targets for e-kerosene derived from green hydrogen [27].

The EU's carbon pricing mechanisms further complement the RED III framework. Although the ETS has historically struggled to incentivise green hydrogen adoption due to low carbon and fuel prices and free emission allowances, RED III signals a shift towards stronger economic instruments. Moreover, the proposed introduction of Carbon Contracts for Difference (CCfDs) is designed to bridge the cost gap between conventional fossil-based hydrogen production and renewable hydrogen alternatives by providing financial support to industries transitioning to low-carbon technologies. CCfDs are a

government-backed mechanism that guarantees a fixed carbon price for investors in green hydrogen projects. If the market carbon price remains below the agreed strike price, the government compensates the producer for the difference, mitigating financial risks and making renewable hydrogen more economically viable. By offsetting the cost disadvantages of clean hydrogen compared to conventional production methods, CCfDs reduce investment uncertainty and encourage large-scale adoption. These measures aim to catalyse investments in hydrogen technologies while maintaining the competitiveness of EU industries in global markets [28].

Infrastructure development is another critical pillar of RED III's implementation. The Hydrogen and Decarbonised Gas Package establishes guidelines for integrating renewable hydrogen into the existing energy system, including repurposing natural gas infrastructure for hydrogen transport and developing dedicated pipelines while introducing a 2% blending-by-volume limit for hydrogen in the existing natural gas grid. This approach supports the scaling of green ammonia as a hydrogen carrier, ensuring its efficient distribution across member states. RED III's emphasis on cross-border cooperation encourages joint projects and shared renewable energy targets, enabling a cost-effective and unified energy transition across the EU [15], [29].

One of the key funding programs is the Important Projects of Common European Interest (IPCEI) for Hydrogen, which collectively involves 16 EU Member States and Norway, mobilizing up to €18.9 billion in public funding and unlocking over €27.1 billion in private investment [30], [31]. The EU has launched four IPCEI initiatives in the hydrogen sector, each addressing different aspects of the hydrogen value chain.

IPCEI Hy2Tech, launched in July 2022, focuses on hydrogen technologies across production, fuel cells, storage, and transportation. It includes 41 projects from 35 companies in 15 Member States, with €5.4 billion in public funding and an estimated €8.8 billion in private investment [30]. In September 2022, IPCEI Hy2Use was introduced to support hydrogen infrastructure and industrial applications, such as large-scale electrolyzers and hydrogen transport networks. This initiative comprises 35 projects from 29 companies in 13 Member States and Norway, backed by €5.2 billion in public funding and €7 billion in expected private investment [30].

In February 2024, the EU approved IPCEI Hy2Infra, which is focused on deploying large-scale hydrogen infrastructure, including 3.2 GW of electrolyzer capacity, 2,700 km of hydrogen pipelines, and large hydrogen storage facilities with a capacity of approximately 370 GWh. It involves 33 projects from 32 companies across 7 Member States, receiving €6.9 billion in public funding and €5.4 billion in private investment [31]. The most recent initiative, IPCEI Hy2Move, was launched in May 2024 and is dedicated to hydrogen mobility, including fuel-cell vehicles, hydrogen-powered trains and ships, and refuelling infrastructure. It comprises 13 projects from 11 companies in 7 Member States, with €1.4 billion in public funding and €3.3 billion in expected private investment [30], [32].

2.2 United Kingdom

In recent years, the UK has developed distinct policies to address carbon emissions, particularly within the hydrogen and ammonia production sectors. With a focus on innovation and sustainability, the UK government has introduced various strategies to promote low-carbon technologies and practices.

The UK has adopted a distinct approach to hydrogen policy. The UK's Hydrogen Strategy, published in 2021, outlines a roadmap for developing a low-carbon hydrogen economy. The strategy focuses on building "green" and "blue" hydrogen production capacity, leveraging the UK's extensive offshore wind resources to support electrolysis. The UK government aims to achieve 5 GW of low-carbon hydrogen production capacity by 2030, supported by the Hydrogen Business Model, which provides financial support to hydrogen producers through Contracts for Difference (CfDs) [33].

Unlike the EU's RED III, the UK's Hydrogen Strategy emphasises less strict temporal and geographic correlation requirements for green hydrogen production. Instead, it prioritises the scalability and cost-effectiveness of hydrogen projects [33]. Devolved administrations like Scotland are also actively pursuing hydrogen strategies, focusing on exporting green hydrogen and derivatives like ammonia to the EU. These regional strategies highlight the economic potential of green ammonia exports for the UK, particularly in aligning with international market trends [3].

The UK's investment in CCS technology also plays a pivotal role in enabling the production of blue hydrogen, which could serve as an interim pathway for decarbonising ammonia synthesis. Recent government announcements have reinforced the UK's commitment to CCS, with the allocation of £20 billion in funding for CCS projects by 2030, targeting industrial decarbonisation and hydrogen production [34].

This support includes the development of track-2 CCS clusters, such as Viking and Acorn, aimed at accelerating deployment across key industrial regions. Simultaneously, the expansion of offshore wind capacity provides the necessary low-carbon electricity for scaling green hydrogen production. This dual approach offers a technological bridge for transitioning ammonia production toward sustainable methods while addressing economic and infrastructure constraints [3].

International and EU regulations also indirectly influence the UK's decarbonisation efforts for ammonia production. Although the UK is no longer an EU member, policies such as the RED III, FuelEU Maritime, and ReFuelEU Aviation establish market demands for renewable fuels, including green ammonia, in sectors where the UK actively participates. These regulations create external pressures and opportunities for the UK to align its ammonia production with emerging global standards, particularly for shipping and aviation applications [3], [33].

However, significant gaps remain in the UK's regulatory framework regarding ammonia-specific policies. Quantitative targets for reducing emissions from ammonia production have not been established, nor have dedicated support mechanisms or incentives for transitioning the ammonia sector to low-carbon pathways. However, it does so indirectly by supporting CCS and hydrogen project development. Addressing these gaps will require more explicit integration of ammonia within the UK's broader hydrogen and climate strategies, alongside sustained investment in renewable energy and CCS infrastructure [33].

2.3 Norway

Norway's abundant natural resources and commitment to environmental stewardship have shaped its approach to decarbonising industrial processes, including hydrogen and ammonia production. The Norwegian government has implemented policies leveraging renewable energy assets to reduce carbon emissions in these sectors.

Norway's approach to hydrogen development has significant implications for its ammonia production industry, particularly in the context of decarbonisation. Historically, Norway has played a pioneering role in ammonia production. As early as 1927, Norsk Hydro utilised electrolysis-based "green" hydrogen to produce ammonia and fertilisers, showcasing the country's early adoption of renewable energy in industrial processes. In 2019, Norway's ammonia production was approximately 225,000 tons annually, primarily utilising "grey" hydrogen derived from natural gas. This production volume is relatively modest compared to other European countries. For instance, Germany, Poland, and the Netherlands collectively account for about 45% of Europe's total ammonia production capacity, each producing significantly more than Norway. These three countries collectively produce approximately 8.9 million metric tons of ammonia annually, which is almost 18 times larger than Norway's production capacity of 0.5 million metric tons per year (Table 1) [9].

Norway's ambitious climate targets, including a 55% reduction in domestic greenhouse gas emissions by 2030, emphasise the necessity of decarbonising its ammonia sector [35]. While Norway's hydrogen strategy primarily focuses on producing "green" and "blue" hydrogen, these developments naturally intersect with ammonia production, which remains a key hydrogen consumer [1], [36]. The technology-neutral approach underpinning the strategy suggests that a range of solutions, including renewable energy-powered electrolysis, CCS, and methane pyrolysis, could be applied to reduce emissions from ammonia production.

Norway aligns its energy policies with EU directives, such as the RED III and CBAM, ensuring that its ammonia sector remains competitive within a decarbonising European market [37], [38]. Policy developments supporting ammonia decarbonisation are already emerging. Yara, one of Norway's leading chemical companies, received €28.3 million to develop a "green" hydrogen demonstration plant to reduce CO_2 emissions in fertiliser production [39]. This project highlights Norway's focus on integrating renewable energy into industrial processes and fostering innovation within the ammonia sector.

Thus, electrifying ammonia production is a potential pathway, aligning with Norway's extensive renewable electricity (e.g., hydro) capacity and its broader strategy to create a "green" industrial sector capable of competing globally. While these initiatives indicate a strong commitment to sustainable ammonia production, significant gaps remain in the policy framework. Quantitative targets for emission reductions specific to ammonia production have not been explicitly outlined, nor are there detailed support mechanisms or incentives tailored to the sector.

2.4 Germany

Germany's industrial prowess and commitment to environmental sustainability have driven its policies to decarbonise hydrogen and ammonia production. The German government has enacted several measures to promote low-carbon technologies and reduce emissions within these industries.

Germany's hydrogen strategy outlines a comprehensive vision for industrial decarbonisation, with significant implications for ammonia production. The country has focused on fostering domestic green hydrogen production and establishing a robust framework for low-carbon hydrogen imports to meet its ambitious targets. Germany aims to secure 95–130 TWh of hydrogen by 2030, with up to 70% of this demand projected to be met by imports. This strategy is supported by the H2Global initiative, a mechanism designed to bridge price gaps between hydrogen producers and buyers through long-term contracts. The first H2Global tender, launched in 2022, focused on green ammonia, underscoring Germany's recognition of ammonia as a critical hydrogen carrier [40].

H2Global operates through long-term hydrogen purchase agreements (HPAs) with producers and short-term hydrogen sales agreements (HSAs) with buyers, structured as a double-auction model. The intermediary entity, Hintco, signs fixed-price, long-term contracts (often ~10 years) with hydrogen producers to provide investment certainty while selling the acquired hydrogen via frequent short-term auctions (typically 1-year deals) to end-users at market-driven prices [41]. This structure ensures stable pricing for suppliers while maintaining market flexibility for buyers. To address the price gap between the high cost of green hydrogen production and the lower market willingness to pay, H2Global employs a CfD-like mechanism: Hintco purchases hydrogen at a higher fixed price and resells it at a lower, market-driven price [42]. The difference is covered by public funding, allowing producers to receive a viable return while making hydrogen more affordable for consumers [43]. This effectively functions as a long-term Contract CfD, where government funding absorbs the difference between the fixed producer price and the fluctuating buyer price [44].

The initiative is implemented through the H2Global Foundation, with Hintco executing auctions and contract management [41]. Germany initially committed €900 million in public funds to cover CfD-style subsidies, ensuring producers are paid their agreed prices while buyers pay market rates [41]. The model is expanding, with additional funding rounds planned, including a €3.5 billion joint initiative between Germany and the Netherlands [42]. The European Commission has endorsed this approach, and H2Global's success is influencing the design of a European Hydrogen Bank, which implements similar auction-based CfD mechanisms at the EU level [44]. By providing long-term price certainty to producers and a flexible market for buyers, H2Global accelerates green hydrogen adoption, demonstrating a scalable solution for bridging the cost gap in early-stage hydrogen markets [41].

Domestically, Germany plans to establish 10 GW of renewable hydrogen production capacity by 2030, corresponding to approximately 28 TWh of hydrogen. This domestic production will be complemented by investments in infrastructure, including a planned 9,700-kilometer core hydrogen network by 2032. This network is intended to connect ports, industries, power plants, and storage facilities, facilitating the integration of imported and domestically produced hydrogen. Germany's broader industrial decarbonisation strategy strongly emphasises the chemical sector, where ammonia production plays a significant role. Historically, this sector has relied heavily on natural gas for hydrogen production. However, Germany's updated hydrogen strategy encourages the adoption of green and blue hydrogen technologies, particularly in hard-to-abate industries, aligning with renewable energy and carbon capture technologies to reduce the carbon footprint of industrial output while maintaining economic competitiveness [40].

Furthermore, Germany's collaboration with European neighbours through initiatives such as the Esbjerg Declaration highlights its commitment to regional partnerships for scaling green hydrogen production. This agreement envisions 65 GW of offshore wind capacity and 20 GW of green hydrogen production by 2030 in the North Sea region, reinforcing the interconnectedness of hydrogen policies within Europe [40]. Despite these advancements, challenges remain. The high cost of green ammonia production and the infrastructure requirements for transporting and storing hydrogen derivatives pose significant barriers. However, Germany's strategy reflects a pragmatic balance between immediate decarbonisation goals and long-term ambitions for industrial leadership in a carbon-neutral economy.

2.5 France

France has actively pursued policies to reduce greenhouse gas emissions, particularly concerning the hydrogen and ammonia production sectors. The French government has introduced initiatives to support the development of low-carbon technologies and enhance sustainability within these industries.

France has implemented a comprehensive strategy to decarbonise its hydrogen and ammonia production sectors, aligning with its broader energy transition goals. The National Hydrogen Strategy, launched in 2020, outlines key objectives to establish 6.5 gigawatts (GW) of electrolysis capacity by 2030, aiming to reduce greenhouse gas emissions in industrial applications [45]. In February 2021, France enacted Ordinance 2021-167, which defines the criteria for renewable and low-carbon hydrogen production. This legal framework sets the standards for hydrogen production methods, ensuring alignment with environmental objectives [46]. While no specific regulations exclusively target ammonia, the decarbonisation of ammonia production is indirectly supported through France's National Hydrogen Strategy. Promoting low-carbon hydrogen, a critical feedstock for ammonia synthesis, facilitates emissions reduction in ammonia production processes [45].

France has committed substantial financial resources to advance its hydrogen industry. The national strategy allocates €7 billion to develop hydrogen technologies, focusing on scaling up electrolysis capacity and fostering innovation. Additionally, France benefits from several EU funding mechanisms that support hydrogen infrastructure and research initiatives. These include IPCEI, the France Relance Plan (€2 billion), which is divided into Hydrogen Territorial Ecosystems (AAP) (€275 million), Hydrogen Technology Bricks and Demonstrators (AAP) (€75 million), and the Hydrogen Production Support Mechanism (€650 million). Other key EU funding sources include Horizon Europe and the Connecting Europe Facility (CEF) for Energy, which finance research, innovation, and cross-border hydrogen infrastructure projects [31], [47], [48], [49].

Decarbonisation incentives for ammonia are integrated within broader industrial support frameworks. The France Reliance recovery plan provides funding to industries aiming to reduce their carbon footprint, which includes ammonia producers transitioning to low-carbon hydrogen feedstocks. Furthermore, France is participating in the Northern Seas Energy Cooperation (NSEC), which facilitates collaborative projects encompassing ammonia-related initiatives [49].

The available sources do not explicitly detail specific financial support per kilogram of hydrogen or ammonia. However, the substantial funding allocated through national and European programs underscores France's commitment to making low-carbon hydrogen and ammonia production economically viable [50]. Moreover, the national hydrogen strategy sets clear deployment milestones, aiming for low-carbon and renewable hydrogen to be 20% to 40% of total industrial hydrogen consumption by 2030 [45].

Table 2: Overview of current regulations, support mechanisms, and financial incentives for Hydrogen and Ammonia in the selected EU, UK, and Norway

Region	H_2 Regulations	NH_3 Regulations	H_2 Support	NH_3 Support	Per kg Support	Timelines	Source
EU	Regulation 2024/1789 and Directive 2024/1788 for hydrogen markets, effective Feb 2025.	RED III aligns ammonia production with renewable energy goals under RFNBO criteria.	€3B allocated through the European Hydrogen Bank; first renewable hydrogen auction held.	Innovation Fund supports projects like Fortescue's Holmaneset (€200M for renewable ammonia).	€0.37-€0.48 per kg (renewable hydrogen auction results).	Member states must align legislation by June 2026; renewable ammonia projects operational by 2027.	[15], [51], [52], [53]
UK	Hydrogen Production Delivery Roadmap targets 10 GW capacity by 2030; supports CCUS strategies.	No specific regulations; supported through hydrogen and CCS strategies.	Funding for projects like Teesside and Humber industrial decarbonisation hubs.	Carbon storage projects (e.g., BP's Teesside site) indirectly support ammonia through CO_2 capture.	Not specified; funding mechanisms in development.	CCUS Track 2; CO_2 capture 20-30 Mt/year by 2030.	[3], [33], [34], [54], [55]
Norway	Developing value chains for low/zero-emission hydrogen; introducing Contracts for Difference in 2023.	Aligns with EU regulations; projects like SkiGa focus on green ammonia.	EU Innovation Fund (€200M for Holmaneset); government partnerships for value chain development.	SkiGa Project: green ammonia with EnBW receiving 100,000 tons annually starting 2027.	Not specified; project funding through partnerships.	Holmaneset: construction begins 2025; commercial operation 2027.	[9], [53], [56]
France	Ordinance 2021-167 (Feb 2021) defines renewable and low-carbon hydrogen; National Hydrogen Strategy launched in 2020.	National Hydrogen Strategy indirectly supports ammonia decarbonisation.	$8.2B national hydrogen strategy for 6.5 GW of electrolysis by 2030; additional funding through EU mechanisms.	Decarbonisation incentives through France Relance recovery plan; integrated strategy for ammonia projects under NSEC.	Not specified; funding allocated for project-specific goals.	Deployment plan milestones: 2023 (10% decarbonised hydrogen), 2030 (20-40% low-carbon hydrogen).	[47], [48], [57], [58]
Germany	National Hydrogen Strategy (2020); Hydrogen Acceleration Law (May 2024) enables infrastructure expansion.	Green ammonia supported via H2Global initiatives and national decarbonisation strategies.	€8B for 62 hydrogen projects; €900M H2Global for importing green ammonia.	H2Global incentivises international ammonia imports; €350M for global hydrogen projects (2021-2024).	€0.3-€0.6 per kg (varies by auction and project).	Core hydrogen grid operational by 2027; IPCEI projects implemented by 2030.	[59], [60], [61]

Source: As shown in the source column in Table 2

3. Pathways for Decarbonising Ammonia Production

Decarbonising ammonia production is vital to achieving Europe's net-zero emissions targets while retaining economic competitiveness. Hydrogen, as a key input for ammonia synthesis, can be produced through various pathways, including SMR, SMR with CCS, biomass gasification, and electrolysis using renewable electricity. While these pathways have been extensively studied, research gaps remain in understanding their economic feasibility under evolving policy frameworks, the implications of time-matching requirements for renewable energy, and the potential for cross-regional trade under mechanisms like the CBAM. The literature review synthesises existing research and identifies key gaps this study aims to address.

3.1 Techno-Economic Feasibility of Hydrogen Pathways in European Ammonia Production

SMR remains the dominant hydrogen production method globally, including ammonia synthesis. While SMR with CCS can reduce emissions by more than 90% depending on capture efficiency and storage availability [62], challenges such as carbon storage infrastructure, residual emissions, and cost-effectiveness require further investigation, especially within the European regulatory context under RED III. Previous studies have primarily focused on the emissions profile of SMR and its role as a baseline technology [1], [57], [63], [64], [65]. For instance, the International Energy Agency [1] highlights that SMR accounts for approximately 70% of global hydrogen production, with emissions ranging from 9 to 12 kg of CO_2 per kilogram of hydrogen produced. Similarly, Bhandari et al. [65] provide a detailed lifecycle assessment of SMR, emphasising its high carbon intensity and the need for mitigation strategies such as CCS.

Going further into SMR using CCS for the ammonia sector, studies have shown that SMR with CCS can significantly reduce emissions from ammonia production. According to a report by DECHEMA and Fertilizers Europe [66], carbon mitigation pathways using CCS could reduce emissions by up to 19% by 2030. The Ammonia Energy Association [67] indicates that Europe has a vast technical CCS capacity of 500 Gt of theoretical CO_2 storage, far exceeding the current emissions from ammonia production. Still, considering SMR with CCS within the European regulatory context under RED III for ammonia production remains to be assessed. Thus, this study addresses this gap by modelling SMR with CCS, considering it within the RED III regime.

Biomass gasification has been explored as a promising pathway for producing carbon-neutral hydrogen, offering the potential to utilise renewable feedstocks such as woody biomass, agricultural residues, and organic waste. Studies have demonstrated that biomass-derived hydrogen can achieve near-zero lifecycle emissions when coupled with CCS or when the biomass is sourced sustainably [63], [68]. For instance, IRENA [63], highlights that biomass gasification can reduce greenhouse gas emissions by up to 80–90% compared to conventional SMR, provided that the biomass is sourced from certified sustainable practices and that carbon capture is applied during the gasification process. Similarly, Creutzig et al. [68] emphasise the importance of sustainable biomass supply chains, noting that large-scale biomass utilisation for hydrogen production must avoid competition with food production, deforestation, and other environmental trade-offs.

However, biomass feedstock availability is highly region-specific, with variations in supply chain logistics, transportation costs, infrastructure readiness [69] and emissions. For example, Hansson et al. [69] found that the cost of biomass feedstock can vary by up to 40% depending on regional availability and transportation distances, making large-scale deployment economically challenging in some areas. Additionally, the environmental impacts of biomass utilisation, such as land-use change and biodiversity loss, require careful consideration [70]. Searchinger et al. [70] argue that without stringent sustainability criteria, biomass gasification could lead to unintended consequences, such as increased carbon emissions from land-use change or reduced carbon sequestration capacity.

While previous research has modelled biogas-based hydrogen production in isolation, there is limited work integrating this pathway with ammonia production within a European-wide energy system. For example, studies such as those by Dincer and Acar [71] have focused on the technical feasibility of biomass gasification for hydrogen production but have not fully explored its integration with ammonia

synthesis or its potential in a broader energy system context. This study addresses this gap by evaluating woody biomass gasification in the context of existing European ammonia plants, accounting for feedstock logistics, lifecycle emissions, and regional energy market dynamics and infrastructure. The findings aim to clarify whether biomass-based hydrogen can play a meaningful role in meeting decarbonisation targets under RED III and related EU policies. This will be particularly important in regions with abundant biomass resources and established supply chains.

Electrolysis, powered by renewable electricity, is widely regarded as the most sustainable long-term solution for hydrogen production. However, its economic viability is heavily influenced by time-matching regulations, which require electrolysers to align their operations with renewable electricity availability to demonstrate additionality. Stricter requirements, such as hourly matching, can significantly increase production costs and limit electrolyser utilisation rates [72]. Flexible operations and hydrogen storage can mitigate these challenges [64], but further research is needed to quantify the financial implications under various time-matching scenarios. This study incorporates both hourly and monthly matching models to assess compliance costs and the feasibility of achieving 70% emissions reductions compared to SMR, unlike previous research, which often focuses on a single hydrogen pathway or assumes uniform conditions [73], [74], this paper will consider multiple hydrogen, by extension ammonia, production pathways and varying market and policy conditions based on both country and regional levels.

3.2 Time-Matching Requirements and Grid Decarbonisation

An important policy gap concerns the readiness of European electricity grids to support hydrogen production under strict additionality and time-matching requirements. Achieving the required emissions reductions—70% for 'clean' hydrogen (RFNBO for renewables, LCF for CCS) and 50% for biomass-based hydrogen (under RED III-Biofuels)—as defined by the European Union's separate criteria, heavily depends on the decarbonization of electricity grids and the effective integration of diverse renewable energy sources[24], [64], [72]. For instance, IRENA [64], highlights that the carbon intensity of hydrogen production via electrolysis is directly tied to the carbon intensity of the electricity used, emphasising the need for grids to transition to low-carbon energy sources to meet clean hydrogen standards. Similarly, Glenk and Reichelstein [72], demonstrate that the economic viability of electrolysis is highly sensitive to grid decarbonisation, with higher carbon intensities significantly increasing the cost of achieving emissions reductions.

However, integrating renewable energy into electricity grids poses significant challenges, particularly in meeting strict time-matching requirements. Time-matching, a key component of the regulation under RED III, mandates that hydrogen production aligns with the availability of renewable electricity monthly (before 2030) and hourly (after 2030). Stricter hourly matching requirements, while effectively reducing emissions, can increase production costs and limit electrolyser utilisation rates [75], due to the intermittency of renewable production requiring costly storage solutions. Zeyen et al. [75], found that hourly matching could increase hydrogen production costs by up to 30% compared to monthly matching, primarily due to the need for flexible operations and energy storage solutions. Conversely, more lenient monthly matching requirements can reduce costs but may compromise emissions reductions, as highlighted by Ferrús et al. [76], who argue that temporal flexibility in matching can lead to higher grid emissions if not correctly managed.

Despite these challenges, few studies have systematically evaluated whether specific EU countries can meet the 70% emissions reduction threshold for clean hydrogen certification by and beyond 2030. Moreover, applying a hybrid case where systems are optimised for monthly matching while the remainder to meet hourly demand comes from the grid is not currently being investigated as a solution to help reduce the economic burden behind sizing renewable capacity. This research addresses this gap by examining the carbon intensity of electricity grids in key EU countries (EU member states, UK, and Norway), projecting whether these grids will achieve the required decarbonisation thresholds. For example, Norway and France are often cited as leaders in low-carbon (nuclear) and renewable energy integration. Norway's grid is predominantly powered by hydropower, while France's grid relies primarily

on nuclear and hydropower [1]. In contrast, countries like Germany[4] and Poland, which still rely heavily on coal-fired power, face potential challenges in meeting the 70% threshold without substantial grid upgrades and policy interventions [77]. Furthermore, the research will investigate the potential of the aforementioned hybrid case and quantify its potential.

3.3 Decarbonised Ammonia as a Traded Commodity

Cross-border trade in hydrogen and hydrogen-derived ammonia presents opportunities and challenges under complex climate policies. CBAM aims to mitigate carbon leakage by applying a carbon tax on imported goods, aligning it with the EU ETS price. However, international shipping emissions remain only partially accounted for, with just 50% of emissions currently covered [78]. This exclusion creates potential arbitrage opportunities, allowing hydrogen or ammonia produced in regions with lower emissions costs (e.g., the United States) to remain economically competitive in Europe, contributing to an unbalanced competitive landscape. Recent studies, such as Chyong et al. [79] and Zhong and Pei [80], have examined the competitiveness of clean hydrogen production in the US under the Inflation Reduction Act (IRA). However, there is limited research on how US ammonia producers can leverage exemptions for international shipping to export ammonia to Europe. This study models trade scenarios incorporating CI thresholds, CBAM costs and RED III requirements, shipping costs, and production incentives under both EU and US regulatory frameworks, identifying the potential of transatlantic ammonia trade and its possible impact on the future decarbonised European ammonia market.

To summarise, this study aims to address challenges in decarbonising ammonia production by focusing on the following objectives:

1. **Comparative Economic Analysis of Hydrogen Production Pathways for Existing Ammonia Production.** This study conducts a comprehensive techno-economic modelling of multiple hydrogen production pathways, including SMR, SMR with CCS, electrolysis, and biomass gasification for ammonia synthesis under the regulatory framework of RED III in 52 different locations that currently hold fertiliser production facilities across continental Europe (plus UK and Norway). The model compares NPV and emissions intensity of the different pathways and identifies the most viable one for decarbonising Europe's ammonia industry in the medium term. The analysis also considers region-specific factors, such as the required renewable energy potential, subsidy support, and operating costs, such as energy and labour costs.
2. **Financial Impacts of Time-Matching Requirements for Renewable Electricity.** The study assesses the financial implications of hourly versus monthly time-matching requirements for renewable electricity in hydrogen production for making ammonia. Stricter hourly matching, as mandated by RED III, can increase production costs and limit electrolyser utilisation rates, while more lenient monthly matching may compromise emissions reductions. The research quantifies the cost penalties and emissions trade-offs associated with different time-matching approaches by modelling both time-matching rules. The research also assesses the potential of applying a hybrid case where renewable energy capacity for an ammonia plant is sized based on monthly matching while the remainder to meet the plant's hourly demand is taken from the electricity grid. The findings will help to infer industry and policy-specific recommendations on balancing additionality and time-matching requirements with economic feasibility while assessing the European grid decarbonisation readiness under a 70% reduction requirement compared to the SMR baseline emissions.
3. **Ammonia Trade under the EU CI thresholds, CBAM, and RED III Constraints.** The study analyses the potential for cross-border ammonia trade, focusing on the implications of the US and European policy and regulations for the decarbonisation of hydrogen. In particular, the study focuses on modelling a trade scenario incorporating the US Inflation Reduction Act, European CI thresholds, CBAM, and shipping costs under RED III requirements for traded

[4] Although Germany is making significant strides in wind and solar energy it still retains some coal generation capacity

ammonia from the USA to the EU. The analysis also explores how potential exemptions for international shipping emissions could influence market dynamics and competitiveness of the European ammonia production[5].

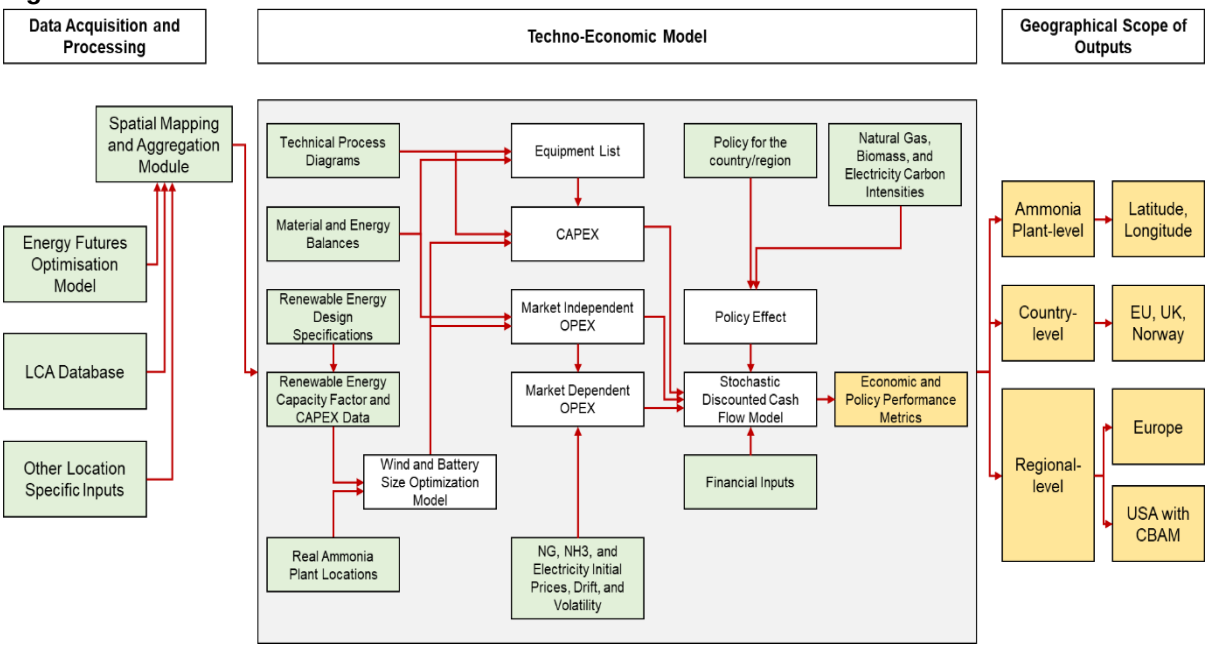
4. Methodology[6]

The research framework is set up to evaluate the feasibility of decarbonising ammonia production in Europe by employing multiple hydrogen production pathways. The pathways include hydrogen via Alkaline Electrolyser Cell (Renewables) using solar PV and onshore wind turbines, natural gas through unabated SMR, abated SMR using CCS, and woody biomass ($BIOH_2$). The model is designed to account for economic, environmental, and policy factors while simulating plant-level operations across European ammonia facilities to answer this report's research questions.

To answer these questions, this paper builds upon a comprehensive techno-economic model in collaboration with the model's developers [79]. Within this paper, the model is further enhanced to address the specific geographic and temporal scopes encapsulated within the goals of this report. Enhancements include adding a data acquisition and processing component and a geographical scope of outputs component, as seen in Figure 2[7].

The research framework developed for this paper contains an updated model built on three main components: (i) the data acquisition and processing module, (ii) the techno-economic model, and (iii) the geographical scope of outputs[8].

Figure 2: Ammonia decarbonisation research framework



Source: Authors' contributions, techno-economic model adapted from [79]

[5] Due to data availability and the potential configurations of shipping variables contributing to varying emissions values, our analysis does not account for shipping emissions. However, as shown in the study, the exclusion of these emissions creates a noticeable gap between US-based ammonia and its European counterpart, warranting further research into how European regulators can ensure a fair competitive playing field

[6] The model and its underlying inputs and results are intended to be open-access to ensure transparency and clarity.

[7] Refer to model SI for a detailed description of the original model iteration, refer to the supplementary information file associated with the cited paper [79].

[8] Within Figure 2, green represents a processed input, white represents a function, and yellow represents an output

4.1 Spatial Analysis and Matching Module

This component of the techno-economic model provides the necessary data for the subsequent calculations necessary to the various European analyses, hereinafter referred to as simulation runs. This data is processed by the Spatial Analysis and Matching Module (SAMM), which matches the data with the relevant geographic data, organises it by specific locations, and aggregates it as regional averages when broader regional analyses are required for the simulation runs. SAMM uses geographic coordinates, longitude and latitude to link ammonia plant locations to their respective countries or regions. Additionally, the inputs are time-dependent, meaning values evolve over different years to reflect projected economic, energy, emissions, and policy conditions for different time horizons. The primary sources of input data are segmented amongst the data from the Energy Futures Optimization Model [81], the LCA Database, and Other Location-Specific Inputs. Within SAMM, the inputs are processed, as seen in Table 3.

Table 3: Decomposition of SAMM

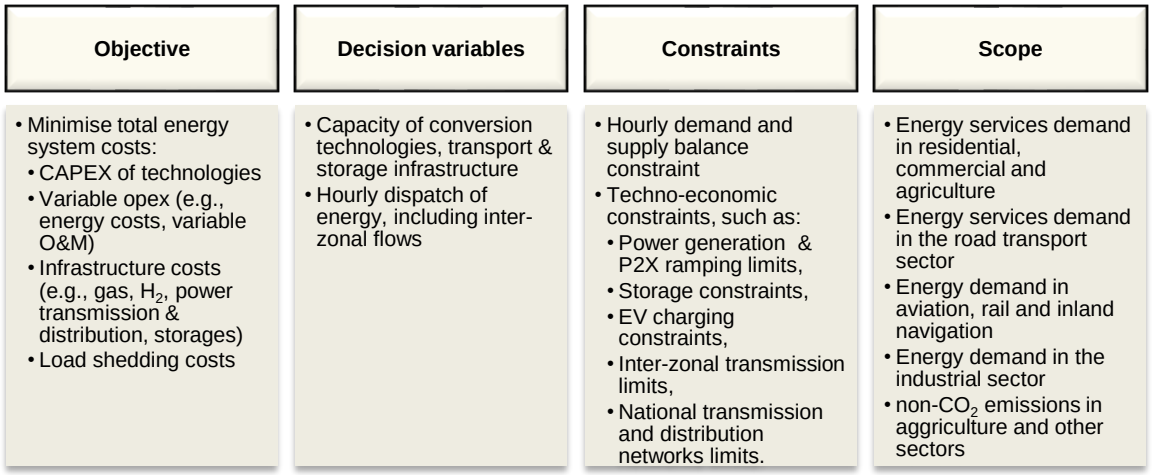
$G(L,S,t) = \{I_{EFM}(L,S,t), I_{LCA}(L,S), I_{OLI}(L,S,t)\}$	
$G(L,S,t)$	The Spatial Analysis and Matching Module (SAMM), which processes data based on location (L), geographic scope (S), and time (t)
$I_{EFM}(L,S,t)$	Inputs from the Energy Futures Optimization Model
$I_{LCA}(L,S)$	Emissions data from the LCA Database
$I_{OLI}(L,S,t)$	Other Location-Specific Inputs

Source: Authors' contributions

4.1.1 The Energy Futures Optimization Model

The Energy Futures Optimization Model (EFOM) provides year-dependent projections up to 2050. A detailed mathematical formulation of the EFOM is provided by Chyong et al. [81]. Figure 3 outlines the high-level EFOM's structure. The energy system model is a partial equilibrium, linear programming optimisation model capable of a detailed representation of a modern and future energy system. It is an economic optimisation model. Its objective is to minimise total energy system costs, comprising capital and operational costs, while meeting exogenously defined (projected) end-user energy services demand, GHG emissions, and other constraints specified by the user.

Figure 3: High-level description of EFOM



Source: [81]

The model represents 27 regions (EU27, UK, Norway, Switzerland, and other global energy importers and exporters), allowing endogenous trade in primary energy. The model covers hourly dispatch and operations of energy conversion technologies and investment in capacities of power generation, end-use low-temperature heat technologies, low-carbon and renewable hydrogen production, electricity-

and hydrogen-based fuels production (e-fuels), end-use road transport technologies (e.g., internal combustion engine cars, battery electric cars, etc.), storage and networks of methane (CH_4), hydrogen (H_2), electricity and CO_2. The model covers the final consumption sectors – residential, commercial, transport, and industry. In terms of supply and transformation technologies, the model takes into account:

- Primary energy supply: crude oil, coal, uranium, biomass, natural gas (fossil origin), biomethane (renewable gas), renewable electricity from hydroelectric, wind, solar, geothermal, marine, etc.
- The natural gas sector includes pipeline transport for natural gas and biomethane and LNG via ships as well as underground storage;
- Secondary energy supply: diesel, gasoline, hydrogen from electrolysis and methane reformation, electricity from thermal generation, and synthetic electrofuels (e-gas and e-liquid).
- power generation (e.g., CCGT CH4/H2, nuclear, bioenergy, hydropower and other renewables, etc.) and storage technologies (e.g., electricity battery storage, hydro pumped storage, etc.) for the electricity sector;
- cross-border trade in energy (primary and derived), including via electricity transmission, CH4 and H2 pipelines;
- end-use technologies and energies in buildings and transport sectors.

The EFOM outputs used in this research are provided in Table 4.

Table 4: Utilised EFOM outputs

$I_{EFM}(L,S,t) = \{P_{NG}(L,S,t), P_{BM}(L,S,t), E_{Grid}(L,S,t), CO_{2-price}(L,S,t)\}$	
$P_{NG}(L,S,t)$	Projected natural gas prices ($/MMBtu)
$P_{BM}(L,S,t)$	Projected biomass prices ($/tonne)
$E_{Grid}(L,S,t)$	Evolution of electricity grid mix
$CO_{2-price}(L,S,t)$	Projected carbon prices ($/tonne)

Source: [81]

Where the Evolution of electricity grid power sources is represented in the following form, in Table 5.

Table 5: Decomposition of the electricity grid mix

$E_{Grid}(L,S,t) = \sum_{i=1}^{n} (\alpha_i(L,S,t) * S_i(L,S,t))$	
$\alpha_i(L,S,t)$	Projected share of power source i in the electricity grid mix (e.g., solar PV, coal, natural gas)
$S_i(L,S,t)$	Carbon intensity of power source i (kg CO_2/kWh)

Source: Cited within Table 14

4.1.2 Inputs from the LCA Database

Emissions intensities for Europe are derived from two primary sources. For natural gas and LNG, intensities are based on landed shipments at the Port of Rotterdam[9] [82], with the total intensity calculated as a weighted average that reflects the 2023 import split between conventional pipeline natural gas and LNG [83]. This approach ensures that the emissions profile is aligned with the regional supply composition and its corresponding transport pathways. In parallel, biomass emissions are

[9] We thank Chyong and Shahabuddin for providing and allowing us to use the life-cycle emissions dataset.

incorporated using data reported by DRAX Group PLC in the UK - which sources woody biomass imported from the US [84] - thus capturing the complete emissions profile associated with this feedstock's sourcing, processing, and transportation.

In the US framework, natural gas emissions intensities are based on national averages that account for the entire supply chain. These emissions intensities include extraction, processing, transportation, and distribution to the export gate [82]. For biomass, emissions intensities rely on data reflecting woody biomass cultivated and processed domestically, as detailed in the model's publication [79].

For Europe and the US, renewable energy sources are assumed to have negligible emissions and thus are treated as zero emissions across both regions.

These input data - spanning both natural gas and biomass - are consolidated and represented in Table 6, providing a view of the emissions intensities across different fuel sources and geographic regions while accounting for the inherent differences in supply chain dynamics.

Table 6: The considered emission intensity input databases

$I_{LCA}(L,S) = \{E_{NG-import}(L,S), E_{BM-DRAX}(L,t), E_{NG-domestic}(L,S), E_{BM-domestic}(L,t)\}$	
$E_{NG-import}(L,S,t)$	Emissions associated with imported natural gas and LNG (kg CO_2/MMBtu), including liquefaction, transport, and regasification. This represents the case where ammonia is produced within the EU using imported NG without CBAM implications on imported natural gas.
$E_{BM-DRAX}(L,t)$	Biomass emission intensity based on the reported Scope 1 and upstream Scope 2 of DRAX Power (kg CO_2/MJ)
$E_{NG-domestic}(L,S)$	Emissions for US domestic natural gas production and transport (kg CO_2/MMBtu), used in the case where ammonia is produced in the US and exported to the EU, making it subject to CBAM
$E_{BM-domestic}(L,t)$	Biomass emission intensity based on the US case cited from the original model's study (kg CO_2/MJ)

Source: Cited within Table 14 and [85]

4.1.3 Other Location-Specific Inputs

In addition to economic and energy factors, several location-specific inputs influence model outcomes. These are time-dependent due to policy evolution, market conditions, and economic trends. They also include assumed functional inputs that remain unchanged from the original model iteration but are considered valid. These inputs are seen in Table 7.

Table 7: Other input variables

$I_{OLI}(L,S,t) = \{S_{level}(L,S,t), D_{duration}(L,S,t), E_{BM}(L,t), C_{labor}(L,S,t), C_{CBAM}(L,S,t), C_{ship}(L,S,t), R_{NH3}(L,S,t), I_{assum}$	
$S_{level}(L,S,t)$	Subsidy levels ($/kgH2)
$D_{duration}(L,S,t)$	Duration of subsidies (n years)
$C_{labor}(L,S,t)$	Labour costs ($/hour)
$C_{CBAM}(L,S,t)$	CBAM costs for ammonia exported to the EU ($/t$NH_3$)
$C_{ship}(L,S,t)$	Shipping costs ($/t$NH_3$)
$R_{NH3}(L,S,t)$	Projected revenue from ammonia sales ($/ t$NH_3$)

Source: [81], [85], [86], [87], [88], [89]

The projected revenue from ammonia sales (R_{NH3}) is determined based on the linear correlation between the Zeebrugge Hub[10] (ZTP) natural gas price [90] and the Ammonia NW Europe CFR price [91], using historical market data from 1996 to 2022, which has a correlation coefficient $(R > 0.95)$ confirming a strong relationship between the two variables. Thus, the linear equation seen in Table 8 is used to project ammonia revenue.

Table 8: Ammonia selling price decomposition

$R_{NH3}(L,S,t) = 39.86 * P_{NG}(L,S,t) + 108.52$	
$P_{NG}(L,S,t)$	Projected natural gas prices ($/MMBtu)

Source: Projection computed based on [85], [90], [91]

In this study, the natural gas price used for ammonia revenue projections is sourced from the Energy Futures Optimization Model, ensuring consistency within the modelling framework. This approach in projecting ammonia prices based on projected natural gas prices remains valid as long as ammonia prices remain coupled with natural gas prices. If future market conditions lead to ammonia price decoupling from natural gas (e.g., due to policy changes, alternative production methods, or supply-demand shifts), adjustments to the projection methodology of ammonia prices would be required. Labour cost projections are based on historical trends in hourly labour costs for the industrial sector [89]. The model extrapolates future labour price trends using these historical data points. The framework assumes gradual wage growth over time, in line with sectoral and macroeconomic trends. Additionally, shipping costs are incorporated into the framework by determining the distance between export and import ports [88] and applying a per-distance shipping cost factor [87]. Finally, $C_{CBAM}(L,S,t)$ is formed through the decomposition seen in Table 9.

Table 9: CBAM decomposition

$C_{CBAM}(L,S,t) = (CI_{SMR\_EU}(L,S,t) - CI_j(L,t) * M_{H2}(L,S,t) * \frac{365}{12} * F_a(L,S,t) * CO_{2-price}(L,S,t)$	
$CI_{SMR\_EU}(L,S,t)$[11]	SMR emissions intensity of European production ($kgCO_2/kgH_2$)
$D_{duration}(L,S,t)$	Technology emissions intensity of US production ($kgCO_2/kgH_2$)
$M_{H2}(L,S,t)$	Mass flowrate of hydrogen (kgH_2/day)
$F_a(L,S,t)$	Availability factor (%)
$CO_{2-price}(L,S,t)$	Projected carbon prices ($/tonne)

Source:[85]

4.2 Discounted Cash Flow Model

This economic analysis employs a stochastic discounted cash flow model centred on a virtual ammonia plant, with conditions shaped by policy, capital and operating costs, and various financial parameters. It evaluates 52 European locations, generating NPV figures and carbon intensity estimates for the aforementioned ammonia production pathways. While the model can provide additional insights, this study focuses on these specific outputs. In the following subsections, we summarise key governing equations and their parameter definitions (for full details of the model, see Chyong et al., 2025 [79]).

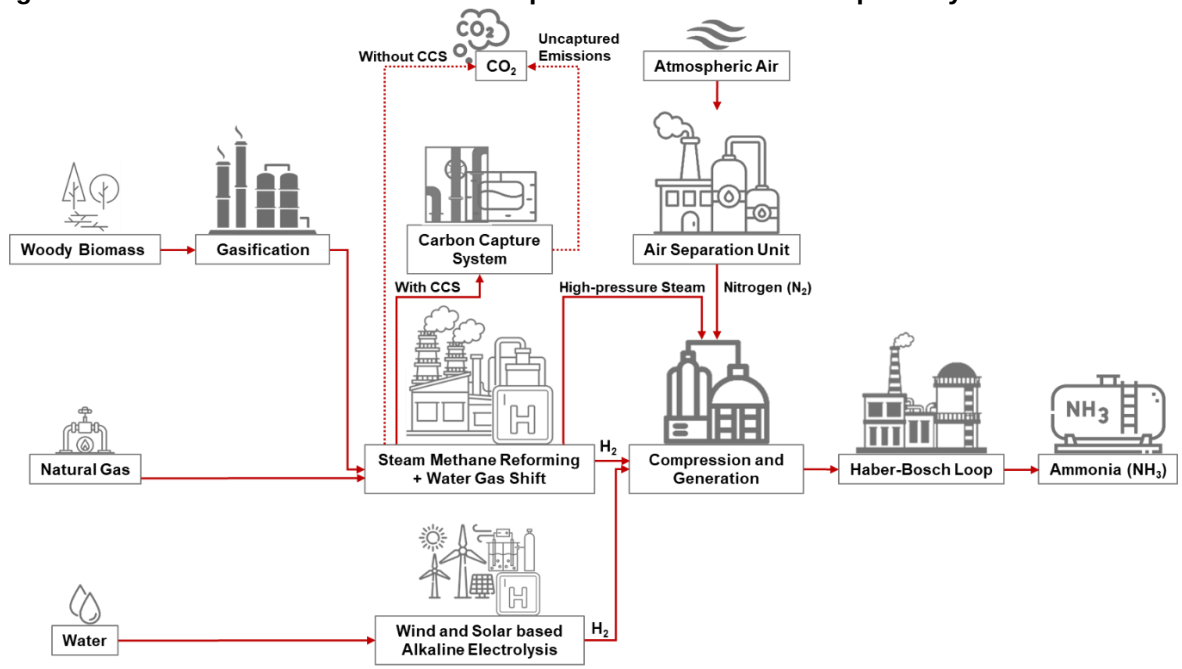
[10] When considering the optimal benchmark for European gas prices, the choice of Zeebrugge (ZTP) over the more common index, the Dutch TTF was done as the correlation analysis between ammonia CFR prices and natural gas prices provided a strong correlation for ZTP among other available indices. Thus, it was selected.

[11] Within our analysis, we apply the carbon accounting methodology outlined in this study. To determine whether a particular pathway can be certified, we use the EU threshold values, which require a reduction relative to a fossil fuel comparator: 70% under RFNBO for renewables, 70% under LCF for CCS, and 50% under RED III-Biofuels for biomass

4.2.1 The Virtual Ammonia Plant

Within the model, the virtual ammonia plant is represented, as seen in Figure 4. The figure illustrates the conceptual layout of the "virtual ammonia plant," highlighting four primary production pathways. The biomass gasification route converts biomass into synthesis gas, forming one of the four potential hydrogen production sources. The steam methane reforming–water gas shift (SMR–WGS) process provides another potential hydrogen pathway with an optional CCS system to reduce stack CO_2 emissions. In this study, hydrogen can be generated via alkaline electrolysis, powered by renewable energy – specifically wind and solar PV. Regardless of their production pathways, hydrogen streams are directed to the compression stage alongside nitrogen sourced through air separation, which is then directed to the final process in the ammonia plant, which involves converting the compressed hydrogen–nitrogen mixture into ammonia via the Haber-Bosch process [85]. Moreover, in this analysis, the ammonia plant capacity remains fixed, thereby excluding potential economies of scale and comparing like for like, and is configured to produce 2717 tons NH_3 per day with an annual availability factor of 0.9.

Figure 4: Structure of the virtual ammonia plant across the different pathways



Source: Adapted from [85]

4.2.2 Discounted Cash Flow Model

This section provides a first-level overview of the Discounted Cash Flow (DCF) methodology applied. We employ a stochastic DCF framework to account for uncertainties in costs, revenues, and policy conditions, enabling a robust assessment of the various ammonia production pathways under consideration. Table 10 presents the NPV formulation used and definitions of each variable. The equation discounts monthly cash flows $CF(T)$ from the start month through the construction and operating phases and normalises by the total ammonia output M_{NH_3} to yield a per-unit measure of project viability. The discount rate d_p is applied monthly, reflecting a Weighted Average Cost of Capital (WACC).

Table 10: Decomposed NPV formulation

$$NPV = \frac{1}{M_{NH_3}} \sum_{T=S}^{Ms+C+L} \frac{CF(T)}{\left(1+\frac{d_p}{12}\right)^{T-Ms}}$$	
T	Considered month (month)
Ms	Month of project start (month)
C	Construction time (months)
L	Operating lifetime (months)
M_{NH_3}	Ammonia production (kgNH_3)
$CF(T)$	Cash flow at time T ($)
d_p	Public discount rate as weighted average cost of capital (WACC)

Source: [85]

where the cash flow $CF(T)$ and public discount rate (d_p) are calculated as seen in Table 11 and Table 12, respectively.

Table 11: Public discount rate decomposition

CAPEX, OPEX, and Policy influenced $d_p = e * R_e + ([1-e] * R_d * [1-\varphi])$	
e	Equity (%)
R_e	cost of equity ($)
R_d	cost of debt ($)
φ	income taxes ($)

Source: [85]

Table 12: Cash flow decomposition

CAPEX influenced / OPEX influenced / Policy influenced $CF(T) = FCI(T) + Land(T) + WC(T) + PMT(T) + Sales(T) + OPEX(T) + Tax(T) + Subsidy(T)$	
$FCI(T)$	Staggered spending to building the ammonia plant ($)
$Land(T)$	costs of purchasing land at time T ($)
$WC(T)$	costs of injecting working capital at time T ($)
$PMT(T)$	Principal and interest loan repayment at time T ($)
$Sales(T)$	Revenue stream from selling ammonia at time T ($)
$OPEX(T)$	Cost of operating the plant ($)
$Tax(T)$	Cost of tax on revenues ($)
$Subsidy(T)$	Revenue from subsides ($)

Source: [85]

The interplay among Capital costs (CAPEX), Operating costs (OPEX), and policy-driven factors (e.g., subsidies, carbon pricing and taxes) are captured in the discounted cash flow framework, reflecting the overall financial structure for producing ammonia at a constant rate across different geographies and pathways. This per-ton NPV metric is crucial for analysing the comparative techno-economic performance of hydrogen production pathways for existing ammonia plants and examining transatlantic trade under the CI thresholds, CBAM and RED III constraints.

4.2.3 Carbon Intensity

Carbon intensity in this analysis is modelled as a function of time T, expressed in units of $kgCO2/kgH2$. This time-dependent approach accommodates potential changes in the different pathways of feedstock supply chains, process efficiencies, and policy frameworks over the study horizon. As summarised in Table 13, the total carbon intensity $CI_j(T)$ is divided into four key components: stack emissions $CI_{Stack}(T)$, supply-chain natural gas emissions $CI_{NG}(T)$, supply-chain biomass emissions $CI_{Biomass}(T)$, and electricity-grid demand emissions $CI_{Electricity}(T)$.

Table 13: Total ammonia plant carbon intensity decomposition

$CI_j(T) = CI_{Stack}(T) + CI_{NG}(T) + CI_{Biomass}(T) + CI_{Electricity}(T)$	
$CI_{Stack}(T)$	Stack emission intensity ($KgCO_2/kgH_2$)
$CI_{NG}(T)$	Supply-chain natural gas emissions intensity ($KgCO_2/kgH_2$)
$CI_{Biomass}(T)$	Supply-chain biomass emissions intensity ($KgCO_2/kgH_2$)
$CI_{Electricity}(T)$	Electricity-grid demand emission intensity ($KgCO_2/kgH_2$)

Source: [85]

In pathways employing CCS $CI_{Stack}(T)$ is reduced by an abatement factor of approximately 95.6% [85]. For woody biomass, $CI_{Stack}(T)$ are not counted, consistent with typical life-cycle accounting conventions for biogenic CO_2. Production powered by wind and solar is assumed to be self-sufficient and thus does not draw power from the grid, effectively negating $CI_{Electricity}(T)$. By contrast, any electricity drawn from the grid follows the projected average emission intensity of the applicable region at time T.

This carbon intensity metric supports all primary research objectives, including assessing whether CCS and biomass pathways meet their respective threshold requirements, determining when European grids may enable sufficiently low-carbon hydrogen production, and evaluating the eligibility of US-produced low-carbon fuels for import into the EU under CI thresholds, CBAM, and RED III constraints.

4.2.4 European Market and Policy Case Design

This section outlines the European case study conducted over the region's near- to mid-term policy targets and investment horizons (until 2040). Each plant is treated as a semi‑islanded facility with integrated, on‑site hydrogen production to account for these variations. Hydrogen is produced at a constant hourly rate to meet hourly ammonia demand. Due to limited facility‑level data on ammonia consumption, we assume an average plant size rated at an ammonia output of 2,717 TPD, ensuring a consistent basis for NPV comparisons and for performing Monte Carlo simulations with varying policy or market inputs and as stated earlier in the methodology, the NPV value is then normalised by a tonne of produced ammonia. Figure 5 shows that 52 ammonia production facilities are distributed throughout Europe, each to mainly supply the fertiliser industry – Europe's principal ammonia user [1]. The model's input is customised at the country and regional level, capturing location-specific factors such as fuel supply costs, renewable energy potential, grid emissions intensity, and policy environments.

Each plant is treated as a semi-islanded facility with integrated, on-site hydrogen production to account for these variations. Hydrogen is produced at a constant hourly rate to meet hourly ammonia demand. Due to limited facility-level data on ammonia consumption, we assume an average plant size rated at an ammonia output of 2,717 TPD, ensuring a consistent basis for NPV comparisons and for performing Monte Carlo simulations with varying policy or market inputs and as stated earlier in the methodology, the NPV value is then normalised by a tonne of produced ammonia.

Moreover, across these 52 sites, four main hydrogen production technologies for making ammonia are analysed:

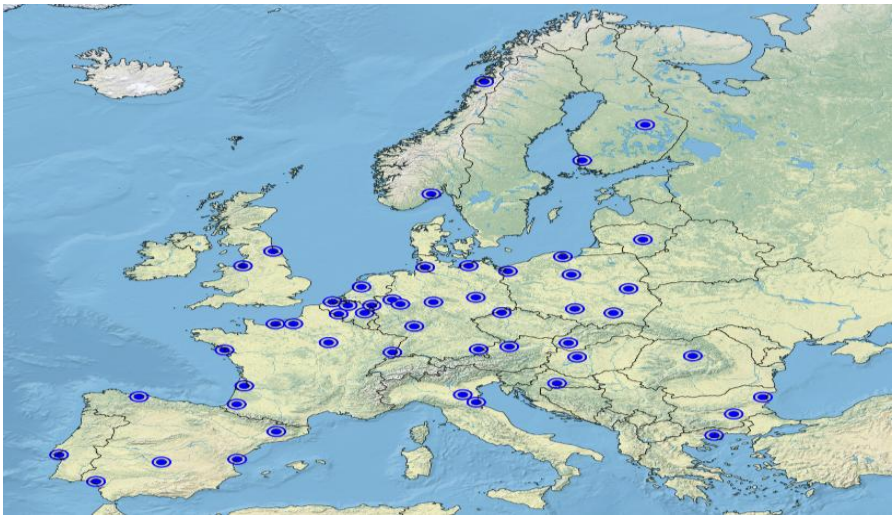
1. **Steam Methane Reforming (SMR)**
   This is a baseline technology reflecting current industry practice. In our modelling, carbon pricing applies to both upstream emissions and direct stack emissions from the reformer.

2. **SMR with Carbon Capture and Storage (CCS)**
   Adopts a 95.6% capture rate for stack CO_2. Residual stack and upstream emissions are subject to carbon pricing, depending on the EU-wide carbon pricing schemes.

3. **Biogas Hydrogen ($BIOH_2$)**
   Harnesses imported woody biomass feedstock from the US, with stack CO_2 treated as carbon neutral. However, upstream supply chain emissions (e.g., cultivation, transportation, and processing) are included.

4. **Alkaline Electrolysis (Renewables)**
   Powered by co-located renewable installations – in the model, wind, solar PV, and battery storage – to meet EU RED III mandates for hourly (temporal) and spatial (geographical) matching with hydrogen production.

Figure 5: Geographical distribution of the Ammonia plants considered within the European case[12]



Source: Authors' contributions based on data from [92]

In alignment with the RED III targets for 2030, the European case ensures that renewable hydrogen production meets hourly and geographical matching requirements (temporal and spatial correlation) and the additionality criterion. This rule implies that electrolysers must be powered by newly installed renewable capacity within the same or neighbouring balancing zone, with power generation occurring in the same hour as hydrogen production. Consequently, the carbon footprint of electrolytic hydrogen is minimised by closely aligning production with locally and temporally available renewable resources.

The analysis also considers potential ammonia imports from the US to capture the interplay between domestic and international policies. In this scenario, CBAM applies, imposing a levy on imported products based on their embedded carbon intensity to ensure a level playing field with domestic producers subject to EU carbon pricing.

Regarding European emission factors considered in this analysis, Table 14 presents the input data for fuel- and technology-specific emissions across various energy sources. The table details supply-chain and combustion emissions ($kgCO_2/MWh_{th}$) for different fuels and their adjusted emission intensities ($kgCO_2/MWh_e$) projected for 2030 and 2040. For the electricity grid, the adjusted emissions for 2030 and 2040 are derived by applying future heat rate factors to combustion emissions, reflecting anticipated efficiency improvements over time. A static heat rate factor is assumed for ammonia plant production, as efficiency gains – primarily expected from retrofitted equipment – are not anticipated within the first 10 years of plant operation.

[12] Refer to Table 16 in the appendix for precise coordinates on the considered locations.

Table 14: Chosen fuel- and technology-specific emissions across various energy sources

Fuel[13]	Supply-Chain Emissions ($kgCO_2/MWh_{th}$) **(a)**	Combustion Emissions ($kgCO_2/MWh_{th}$) **(b)**	2030 Adjusted Emissions[14] ($kgCO_2/MWh_e$) **([a+b]*2030 Factor)**	2040 Adjusted Emissions[11] ($kgCO_2/MWh_e$) **([a+b]*2040 Factor)**
Ammonia Plant Production Intensity				
Natural Gas (SMR)	70	(112-243)	(395-679)	(395-679)
Natural Gas (CCS)	70	(5-11)	(163-176)	(163-176)
Biomass ($BIOH_2$)	328	0	0	0
Solar PV and Wind (Renewables)	0	0	0	0
Electricity Grid Intensity (Emissive[14])				
Natural Gas (CH_4) - Combined Cycle Gas Turbine	70	204	570	504
Natural Gas (CH_4) - Combined Cycle Gas Turbine with CCS	70	9	184	172
Coal - Bituminous	14	326	738	731
Coal - Bituminous with CCS	14	14	76	72
Coal – Lignite	14	376	928	905
Coal – Lignite with CCS	14	17	97	93
Oil – Steam Turbine	27	270	849	849
Biomass – Steam Turbine	70	0	0	0
Biomass – Steam Turbine with CCS[15]	70	0	0	0
Nuclear – Generation III	15	0	0	0
Electricity Grid Intensity (Clean)				
Solar PV	0	0	0	0
Wind - Onshore	0	0	0	0
Wind - Offshore	0	0	0	0
Tidal	0	0	0	0
Geothermal	0	0	0	0
Hydroelectric	0	0	0	0

Sources: [81], [82], [84], [93], [94], [95]

[13] For biomass and nuclear, only supply chain emissions are considered.
[14] For Ammonia Plant Production Intensity, the "Factor" reflects the efficiency of converting feedstock into hydrogen, whereas for Electricity Grid Intensity, it denotes the heat rate to represent emissions per unit of electricity generated.
[15] While this would typically be classified as negative emissions, it falls outside the scope of this research and is therefore treated as neutral. Moreover, for most of the European countries considered, it is expected to account for less than 5% of the grid by 2040 (with Belgium as an exception, projected to reach 9.8%). By 2030, its impact remains below 1%. See Table 25 in the appendix for more details on the electricity grid splits.

Within this regulatory framework, two primary policy scenarios are evaluated to reflect different degrees of government intervention:

1. **Reference Case Scenario (RCS)**
   RCS represents no pre-existing support measures. No hydrogen subsidies are introduced, and carbon prices for ammonia are not considered. Consequently, low-carbon or renewable-based pathways receive no financial incentives.

2. **Policy Support Scenario (PSS)**
   In contrast, PSS features a rising carbon price for the ammonia sector – increasing from 68 €/tCO_2 in 2030 to 166 €/tCO_2 by 2050, taken from the reference case of EFOM. Although EU ETS prices are higher – averaging between 65-80 EUR/tCO_2 from early 2022 to early 2025 [96].

   Additionally, this PSS scenario includes a hydrogen subsidy of 0.5 \$/kgH_2 for EU producers, available for 10 years starting in 2030. This subsidy is based on the approved bids from the first auction round of the European Hydrogen Bank, which grants support for a 10-year duration. In this auction, seven projects were approved, including four ammonia production projects that secured a subsidy of 0.48 EUR/kgH_2 (approximately 0.5 \$/kgH_2) [86], [97].

   This subsidy level is considered the support price in our modelling, as the approved projects reflect a European-wide mechanism rather than national support schemes. Notably, one of the selected projects, SKIGA, which is intended for ammonia imports to Germany, is based in Norway, demonstrating that the subsidy framework applies beyond the EU [98].

   While we acknowledge the United Kingdom's support schemes, such as the Hydrogen Allocation Round (HAR1) [99], which allocated \$ 3 billion for 125 MW of green hydrogen projects – equating to approximately \$ 9.65/kgH2[16] - applying this level of support to the two ammonia plants in the UK would require \$ 46 billion in subsidies. This amount, equivalent to approximately 1.4% of the UK's 2023 GDP [100], would be financially challenging for public funding on ammonia support alone. However, if the UK subsidy were aligned with the EHB's recent grant of \$ 0.5 per kg of hydrogen, the total required subsidy would be nearly \$ 2.4 billion – less than the amount allocated in HAR1. For this reason, we assume UK ammonia subsidies align with the EU's EHB subsidy.

By comparing outcomes under these two policy scenarios, the study demonstrates how changes in carbon pricing and hydrogen subsidies affect the feasibility and cost-competitiveness of various ammonia production pathways and the overall decarbonisation trajectory within Europe.

4.3 Geographical Scope of Outputs

Understanding the geographical scope of the study is crucial to assessing the techno-economic feasibility of ammonia production and trade under evolving energy policies and market dynamics. This section outlines the geographic scales considered in the analysis, distinguishing between plant-specific, national, and international perspectives.

[16] Calculations are based on the estimate of \$3 billion in total support over 15 years [99], assuming an electric input capacity of 125 MW, a 90% capacity factor, and 70% electrolysis efficiency. Under these conditions, the total energy input is 125 MW × 0.90 × 8,760 hours × 15 = 14,782,500 MWh-e. When converted to hydrogen at 70% efficiency, this equals 10,347,750 MWh-th, which corresponds to approximately 310,743,243.24 kg of H_2. Consequently, \$3 billion in subsidies over this total output equates to about \$9.65 per kg of H_2.

4.3.1 Geographical Scope

This study examines two sets of analyses at different geographic scales. The first set focuses on the ammonia plant location and country levels, encompassing the plant locations and countries listed in Table 15 [17].

Table 15: European countries with the considered ammonia plant locations

EU countries	Non-EU countries
Austria, Belgium, Bulgaria, Croatia, Czechia, Finland, France, Germany, Greece, Hungary, Italy, Lithuania, Netherlands, Poland, Portugal, Romania, Slovakia, Spain.	Norway, UK.

Source: [92]

By examining location-specific and national-scale factors, the model captures variations in grid emission intensities, renewable resource availability, and labour costs across Europe's energy landscape. We quantify these distinctions in the results analysis, demonstrating that they influence the economic performance of a potential ammonia plant investment decision, particularly in the context of RED III.

In contrast, the second set of analyses – focused on transatlantic ammonia trade under the CI thresholds, CBAM and RED III constraints – is conducted at both EU- and US-wide scales. This broader perspective addresses trade considerations that extend beyond individual national circumstances, particularly the impact of CBAM on US ammonia imports into the European market.

4.3.2 Ammonia Trade Case

To explore the potential for transatlantic ammonia trade, this study incorporates a US-based scenario in which key variables – fuel prices, emissions factors, policy drivers, and labour costs – are calibrated to US conditions. The ammonia is subsequently shipped from the US port of south Louisiana to the port of Rotterdam, both strategically located for shipping from the US and into the EU, and both capable of handling ammonia. Key differences between the EU and US cases include our consideration of CBAM, the IRA policy effect, the incorporation of shipping costs, and the reversion of EU-specific variables to their US-based counterparts, as reflected in the original model iteration. Comparisons are made with European producers to determine whether US ammonia can remain economically competitive once it arrives in the EU.

A key aspect of this trade analysis is the carbon intensity of US-produced ammonia. To qualify as decarbonised under the modeled scenarios, ammonia must achieve a 70% reduction in carbon intensity for Renewables and CCS, and 50% for $BIOH_2$, relative to the EU-set fossil fuel comparator of 94 gCO_2e/MJ. Compliance with these thresholds is assessed within RFNBO, LCF, and RED III-Biofuels [15], [24]. Unlike the accounting methods used for CBAM and ETS, these frameworks mandate the inclusion of upstream and production-related emissions in their assessments[18].

5. Results and Analysis

This section presents the findings [19], focusing on the economic feasibility of different hydrogen production pathways for ammonia in Europe (Section 5.1), the financial implications of time-matching requirements for renewable hydrogen (Section 5.2), and the competitiveness of transatlantic ammonia

[17] Refer to appendix A1 for location specific information.
[18] Our analysis does not strictly follow the specific carbon accounting methodologies set within each EU framework. This decision is based on: (a) The LCF methodology remains a draft, making definitive application challenging, while RED III's $BIOH_2$ criteria apply to transport fuels rather than ammonia production. (b) Despite differences in accounting approaches, both RFNBO and LCF require a 70% CO_2 reduction (50% for $BIOH_2$), which we adopt as a reference to ensure a consistent comparison across pathways.
[19] The model and its underlying inputs and results are intended to be open-access to ensure transparency and clarity.

trade under the CI thresholds, CBAM and RED III constraints (Section 5.3). The analysis is structured to provide insights into the cost dynamics of various ammonia production methods, the influence of subsidies and carbon pricing, and the potential for policy-driven shifts in ammonia supply chains.

5.1 Economic Feasibility of Hydrogen Pathways in European Ammonia Production

This section examines the potential of various hydrogen production pathways to supply ammonia plants across Europe, focusing on economic performance and environmental considerations. The analysis centres on NPV calculations, spatial impacts of critical inputs (renewables availability and labour cost) of plant locations, and policy instruments, specifically subsidies and carbon cost. Section 5.1.1 compares the NPVs of multiple ammonia production pathways at a country-specific level, providing insight into how local conditions influence investment viability. Section 5.1.2 builds on these findings to showcase the countries with the highest and lowest NPV values. Section 5.1.3 goes beyond the country level and looks at the plant location level to identify the most promising sites for green ammonia production, incorporating regional resource availability and cost parameters. Section 5.1.4 evaluates the role of subsidies required to bridge the cost gap between green ammonia production and existing SMR assets. Finally, Section 5.1.5 examines the impact of subsidies and carbon pricing on NPVs, highlighting the significance of effective policy measures in accelerating the adoption of low-carbon ammonia pathways.

Of note in this results and analysis section is that the EU currently supports only renewable-based hydrogen in its subsidy framework, as observed in the European Hydrogen Bank's latest subsidies. Moreover, in our analysis, production from CCS-based hydrogen and $BIOH_2$ does not meet their respective CI reduction thresholds—at least 70% for CCS and 50% for $BIOH_2$—compared to the fossil fuel comparator. As a result, these pathways are not considered eligible for subsidies under the PSS cas[20]. However, if upstream emissions were excluded—thus deviating from the RFNBO methodology—both CCS-based hydrogen and $BIOH_2$ would surpass the 70% emissions reduction threshold.In the case of CCS hydrogen, the only remaining emissions would stem from uncaptured CO_2 at the combustion stack, which accounts for less than 5% of the total emissions intensity of SMR. Meanwhile, $BIOH_2$ would effectively achieve a 100% reduction relative to SMR, as its combustion is considered carbon neutral. This suggests that under a different regulatory framework, both CCS and $BIOH_2$ could be viable low-carbon alternatives for hydrogen production.

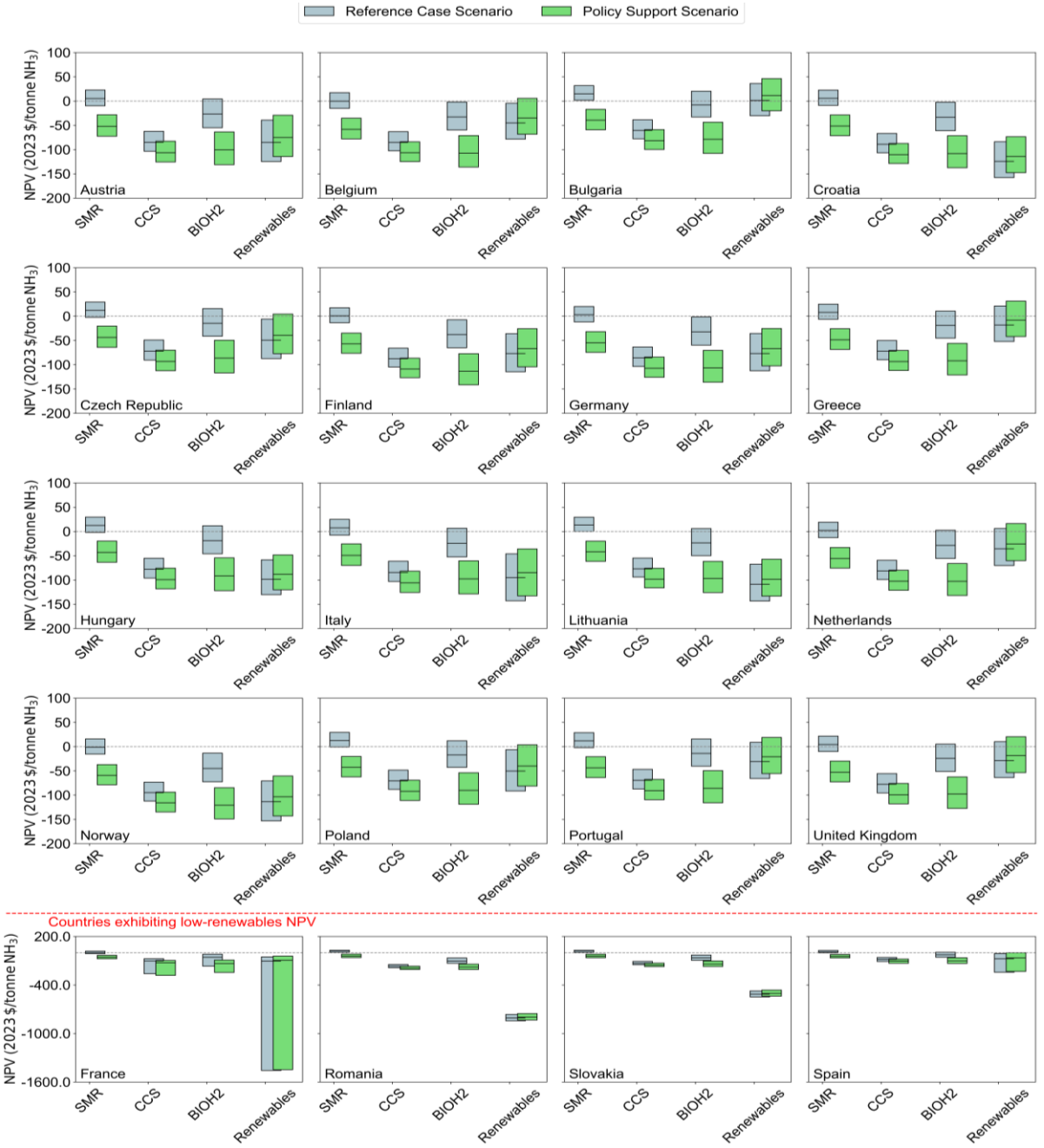
Additionally, one 'hidden' factor that plays a crucial role between 2030 and 2040 is the learning curve in cost reduction, which the model takes into account. Learning curves describe the gradual cost reduction as technology scales up, efficiency improves, and supply chains mature. This concept is particularly relevant to renewable hydrogen and electrolyser technology, where production costs decline with higher global deployment and industrial scaling. Importantly, these cost reductions are not automatic – they require investment now to unlock long-term gains. As a result, even if cost structures appear similar across periods, the 2040 case would show more favourable NPV values, as cumulative deployment leads to lower capital and operating costs. Indeed, this underscores the importance of stepping away from the 'chicken or egg' hesitation common in hydrogen investment circles – where uncertainty around demand delays supply-side investment and vice versa. Overcoming this inertia requires early and decisive public support in developing hydrogen infrastructure, ensuring that economies of scale, technological learning, and supply chain maturation drive down costs over time. Without this forward-looking approach, the industry risks stagnation before it reaches critical mass, whereas early action can secure competitive production costs and economic viability in the long term.

[20] Indeed, even if CCS and $BIOH_2$ achieve carbon intensities well below their respective thresholds, they would still not qualify for subsidies, as EHB subsidies are currently limited to renewable-based hydrogen. This approach could be criticised for not aligning with the principle of energy agnosticism.

5.1.1 NPV of Ammonia Pathways at the Country-level in Europe

The economic analysis of ammonia production pathways across Europe assesses financial viability through NPV under two policy scenarios: the RCS and the PSS for 2030 and 2040. The results of this can be seen in Figure 6 and Figure 7.

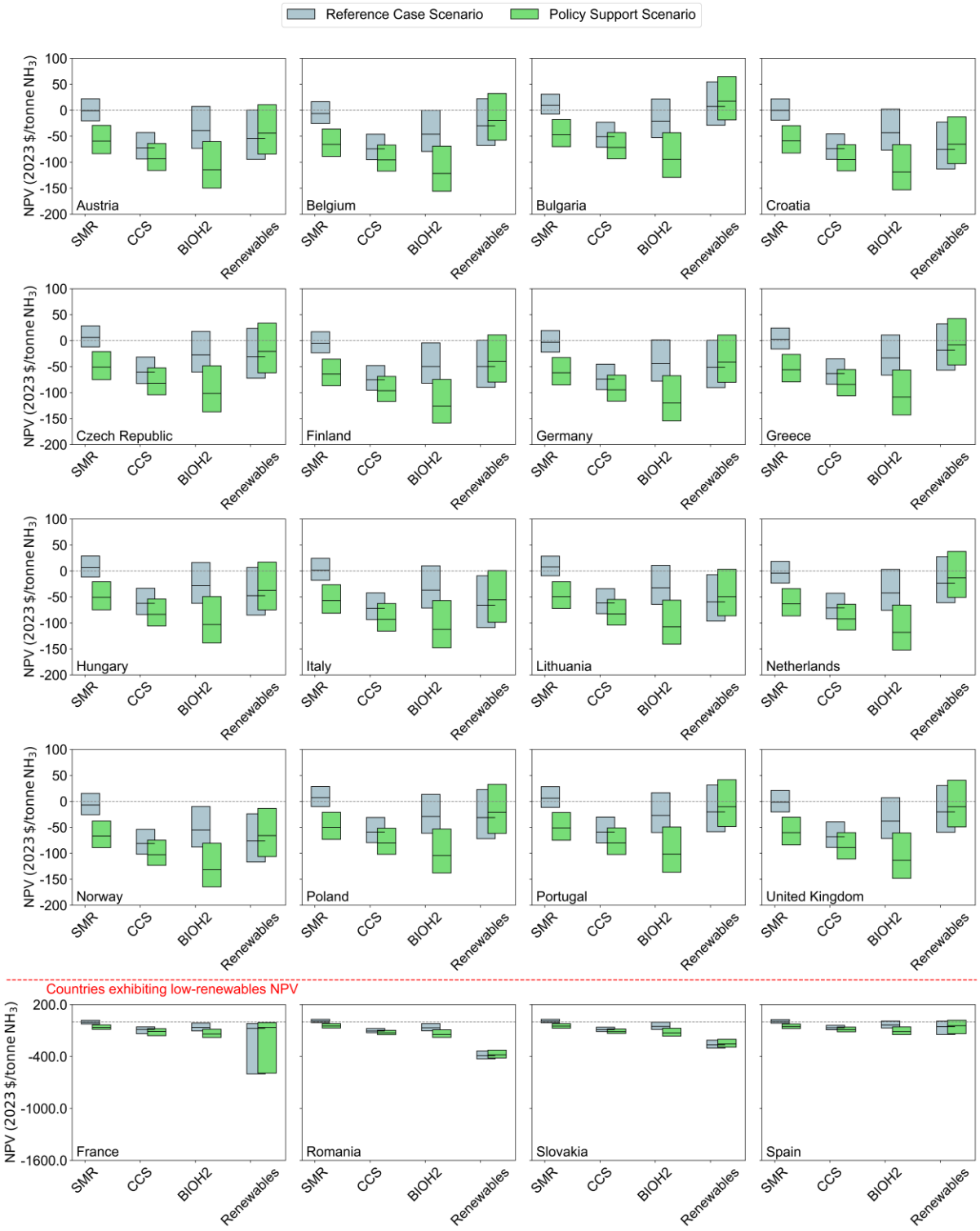
Figure 6: 2030 interquartile NPV range (25th percentile - median - 75th percentile) for the two considered scenarios[21,22]



Source: Authors' contributions

[21] NPV values for 2030 and 2040 shown in the figures can be seen in Table 17 and Table 18 in the appendix.
[22] Renewable resource availability for each location and the country's average industry labour costs can be seen in Table 19 and Table 20 in the appendix.

Figure 7: 2040 interquartile NPV range (25th percentile - median - 75th percentile) for the two considered scenarios[21]



Source: Authors' contributions

A key aspect of this analysis is the islanded production setup, where all hydrogen and ammonia production occur independently from the electricity grid. In the case of green ammonia, renewable electricity from wind and solar, coupled with battery storage – through an optimisation model, is sized

to meet the continuous energy demand of the ammonia plant. This ensures hourly matching of supply and demand, in line with the RED III Delegated Act requirements for renewable hydrogen production, preventing any reliance on grid electricity.

Under RCS, where neither carbon pricing nor subsidies are applied, depreciated SMR-based ammonia production remains the most financially competitive due to its relatively low operational costs and the absence of reinvestment requirements. In contrast, all low-carbon hydrogen-based ammonia pathways – including $BIOH_2$, CCS, and Renewable-based ammonia – exhibit significantly lower NPVs[23], reflecting the capital-intensive nature of new infrastructure development, particularly for fully islanded renewable setups that require oversized solar, wind, and battery storage capacities to ensure uninterrupted hydrogen supply. Even in regions with abundant renewable energy, the need for large-scale energy storage and dedicated power generation increases the cost burden, keeping green ammonia NPVs negative despite their lower emissions profile.

When shifting to the PSS, where carbon pricing is introduced for SMR, CCS, and $BIOH_2$, while renewable ammonia receives subsidies, a significant shift in financial performance occurs. Applying a carbon price on SMR-based production lowers its NPV, reducing its economic advantage over alternative pathways. Interestingly, in this analysis, the biggest hit is absorbed by $BIOH_2$, which is taxed for its upstream carbon emissions but does not receive subsidies for its low-carbon state, as in PSS, no financial support is provided. This pattern applies to CCS but to a lesser degree.

Furthermore, $BIOH_2$ and CCS are both low-carbon pathways. However, our analysis shows they failed to achieve their respective EU CI reduction targets, mentioned earlier in this section, a key requirement under EU sustainability criteria. The primary reason for this failure is the high supply chain emissions associated with biomass logistics and natural gas processes, which limit their overall emissions savings potential. This further weakens their financial outlook, as these pathways remain subject to carbon pricing without access to subsidy mechanisms that could otherwise offset their costs.

Conversely, renewable ammonia benefits from targeted subsidies, partially mitigating its high capital investment requirements. In existing SMR production sites with abundant and less variable renewable energy resources, such as Spain, Portugal, and Nordic countries, the NPV of green ammonia improves significantly, narrowing the financial gap with SMR-based production[24]. However, in existing high-energy-cost production sites such as those in Germany and Austria, the need for more extensive battery storage and overbuilt renewable generation results in NPVs that remain significantly lower than that of depreciated SMR. The financial viability of green ammonia remains highly dependent on local renewable resource availability, with wind-rich locations benefiting the most due to lower variability and reduced storage requirements.

Despite these policy-driven shifts, NPVs for most hydrogen-based ammonia pathways remain negative in 2030 and 2040, reflecting the continued financial challenge of establishing self-sufficient, islanded hydrogen production systems without grid backup during hours without sun or wind availability. While cost reductions in electrolysers, battery storage, and renewable energy infrastructure are expected over time, these improvements alone do not fully close the competitiveness gap with depreciated SMR, which continues to operate as the least-cost option due to its relatively low operating expenses and lack of reinvestment needs. Renewable and low-carbon ammonia pathways will struggle to achieve widespread adoption within the given timeframe without a mix of more substantial financial incentives or policy exemptions for RED III matching requirements.

Moreover, the results emphasise that carbon pricing alone cannot financially make alternative hydrogen-based ammonia pathways relatively viable, particularly as $BIOH_2$ and CCS-based ammonia continue to lack access to subsidies. While the pricing of SMRs reduces their attractiveness, existing

[23] Within much of the results and analysis section, the Interquartile Range (IQR) is used for insight analysis. IQR measures the spread of the middle 50% of a dataset, calculated as Q3 - Q1, where Q1 (25th percentile) and Q3 (75th percentile) define the central range. It helps detect outliers, with values below Q1 - 1.5×IQR or above Q3 + 1.5×IQR considered extreme. Unlike standard deviation, IQR is robust against outliers

[24] Refer to Table 19 in the appendix for the availability factor for each location and Table 21 and Table 22 for the NPV of each location in 2030 and 2040.

depreciated SMR facilities still maintain a cost advantage, particularly in locations with low renewable resources and thus higher per renewable energy unit costs. The effectiveness of policy interventions also varies significantly across different European regions, with locations that combine low labour costs and strong renewable availability seeing the most improvement for green ammonia. At the same time, countries with high labour costs and relatively lower-than-average renewable availability at their plant locations, such as Norway and Finland, continue to struggle with competitiveness.

Looking forward to 2040, some expected cost improvements in electrolysis, battery storage, and renewable infrastructure are expected to enhance the financial case for green ammonia. However, unless accompanied by more aggressive policy support, through higher carbon pricing on unabated SMR-based production and additional financial mechanisms to support the aforementioned low-carbon hydrogen pathways, the transition to low-carbon ammonia remains challenging as the persistence of depreciated SMR as a low-cost alternative underscores the difficulty of displacing conventional production methods purely through market forces without more substantial public support.

Going from Figure 6 to Figure 7, across all countries, NPV values generally improve from 2030 to 2040, primarily due to assumed learning-by-doing effects that lead to lower capital and operating costs over time for renewable and electrolysis technologies. This is particularly evident in renewable-based ammonia production, which benefits from declining electrolyser costs, improved efficiency, and expanded renewable deployment. Additionally, CCS and $BIOH_2$ pathways see some economic improvements, though their dependence on feedstock costs limits the extent of their gains. Countries with low labour costs and strong renewable energy availability experience the most significant NPV improvements, making them more competitive locations for green ammonia production. Conversely, fossil-fuel-dependent and high-cost energy markets struggle, particularly where carbon pricing pressures remain intense.

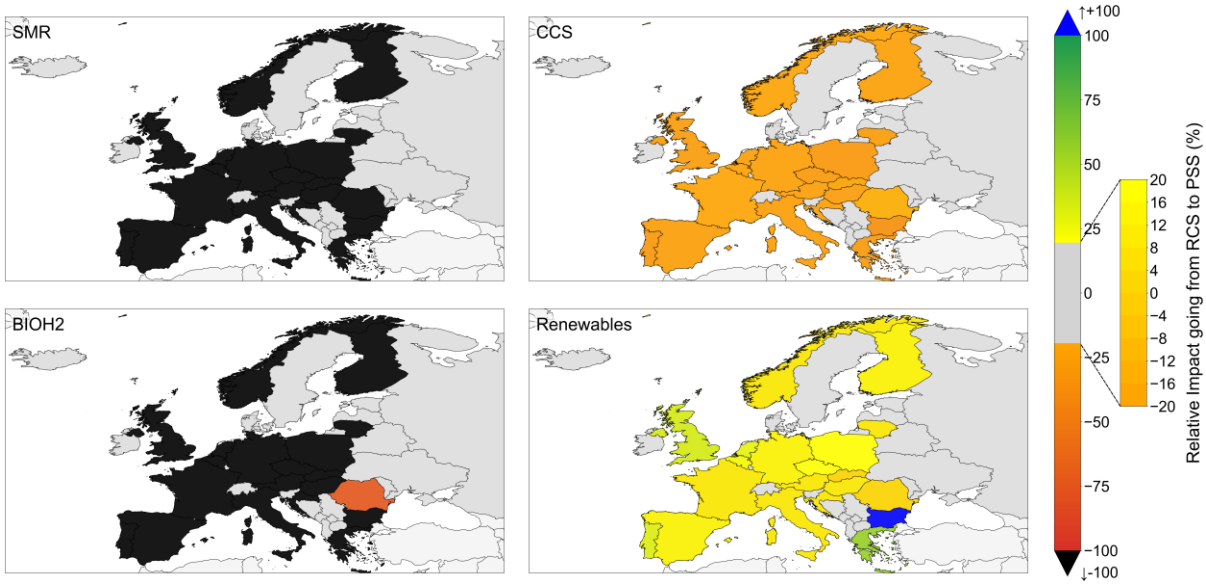
Among the best-performing countries for renewable ammonia, Bulgaria, Greece, Portugal, the Czech Republic, and Poland show the most significant improvements in 2040. These regions benefit from a favourable combination of substantial renewable resources at existing plant sites and relatively low labour costs, which reduces overall production expenses.

By contrast, France, Romania, Slovakia, and Spain perform poorly for renewable ammonia due to geographic constraints and energy cost structures. France, in particular, displays a wide range of NPVs, reflecting the diverse distribution of existing ammonia plants – some located in regions with substantial renewable resources, while others are in less favourable areas that require oversized renewable capacity and battery storage[25], significantly driving up costs. Additionally, France's higher-than-average labour costs further reduce competitiveness. Similarly, despite having low labour costs, Romania and Slovakia struggle as their existing ammonia plants are in locations with weak renewable availability, necessitating costly oversized capacity or storage measures. Spain follows a similar pattern to France, with less severe impacts due to lower labour costs and slightly better renewable conditions in existing ammonia production locations.

When considering the shift from RCS (no pricing or subsidy) to PSS (carbon pricing on emissions for SMR, CCS, and $BIOH_2$, alongside subsidies for renewable ammonia production) results in notable shifts in financial viability across different ammonia production pathways, relative scale results of which can be seen in Figure 8 and Figure 9. The key drivers of this change in the model are CAPEX for CCS, $BIOH_2$, renewables, labour costs, carbon pricing on emissions, and renewable availability for renewables-based ammonia production.

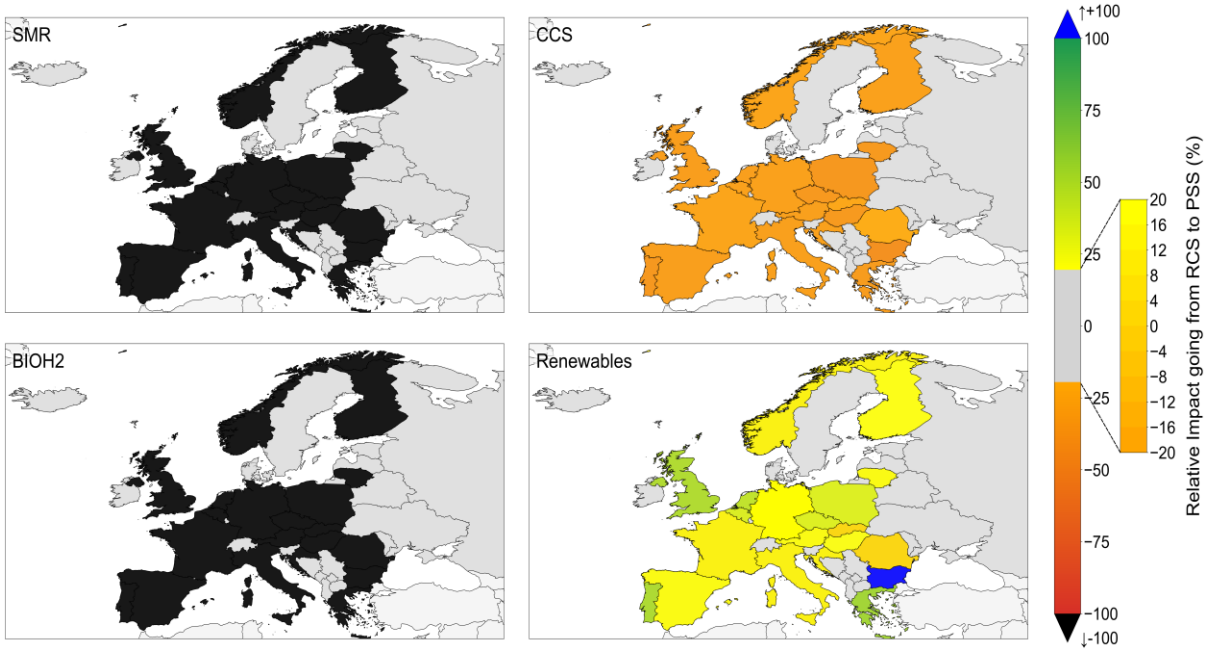
[25] Refer to Table 17 and Table 18 for the specific NPV values for 2030 and 2040, and to Table 19 for the renewables availability at each location, as shown in the appendix.

Figure 8: 2030 relative impact heatmap showing the transition from RCS to PSS in the considered European countries



Source: Authors' contributions

Figure 9: 2040 relative impact heatmap showing the transition from RCS to PSS in the considered European countries



Source: Authors' contributions

Across all countries, SMR, CCS, and $BIOH_2$ experience a decline in NPV under PSS, driven by the introduction of carbon pricing on emissions. However, while the relative percentage drop in NPV appears substantial in some cases, the absolute difference is often small, particularly in cases where NPVs were already negative under RCS. In contrast, as mentioned earlier, renewable ammonia benefits from subsidies, improving NPV values across most regions. However, the scale of this improvement is highly dependent on renewable availability and CAPEX conditions. Countries such as Bulgaria, Greece, Portugal, and Poland see notable positive shifts, as their favourable renewable resources and lower labour costs enhance the impact of subsidies. Meanwhile, in France, Romania, and Slovakia, where existing ammonia plants are located in areas with weak renewable availability, the gains remain limited

due to the need for oversized renewable capacity and energy storage, which increases CAPEX requirements. Spain follows a less extreme version of this trend, where lower labour costs and moderate renewable availability help mitigate some of the constraints in France, Romania, and Slovakia.

Also noteworthy is that introducing carbon pricing disproportionately impacts CCS and $BIOH_2$, particularly in countries where these pathways already face high-cost burdens. While subsidies shift the economic balance favouring renewable ammonia, the gap between low-carbon and renewable pathways widens under PSS. The most notable changes for the carbon pricing pathways (SMR, CCS, $BIOH_2$) occur in countries where the starting NPV under RCS was close to zero, as even a moderate carbon price can push these values further into negative figures, exaggerating the perceived relative decline when compared with the absolute decline. In contrast, for countries where CCS and $BIOH_2$ were already struggling under RCS, such as Romania, the absolute impact of pricing is less dramatic since these technologies already had low NPVs

Indeed, the results highlight that PSS creates a clear financial advantage for renewables, but its effectiveness varies depending on country-specific conditions. These findings emphasise the need for a more regionally focused policy approach that balances financial support across multiple low-carbon pathways. While green ammonia is emerging as the most viable alternative, its competitiveness remains uneven across Europe, and excluding other low-carbon hydrogen pathways may limit the resilience of the ammonia supply chain. If current trends persist, renewable ammonia will dominate in regions with favourable conditions, while countries with high energy costs may require additional policy adjustments to enable a cost-effective transition.

Also, developing the Pan-European hydrogen pipeline infrastructure is a potential solution for countries with low NPV values for renewable ammonia production. Our results indicate significant disparities in renewable resource availability across EU member states, leading to significant cost differences in green hydrogen production. Countries with abundant renewable resources and lower production costs – such as Portugal, Greece, and Bulgaria – could serve as hydrogen exporters. In contrast, nations with weaker renewable availability, such as France, Slovakia, and Romania, could import cheaper renewable hydrogen rather than relying on local production with high CAPEX requirements.

To summarise, the analysis of NPV across ammonia production pathways in Europe under different policy scenarios highlights the complex economic landscape of low-carbon ammonia production. While carbon pricing effectively reduces the financial viability of SMR-based ammonia, the absence of subsidies for $BIOH_2$ and CCS-based ammonia further weakens these pathways, preventing them from becoming viable alternatives despite their lower emissions potential. At the same time, renewable ammonia benefits significantly from targeted financial support, but its competitiveness remains highly dependent on local renewable energy availability, CAPEX, and labour costs. The relative change in NPV further reinforces the divergence between green ammonia and other low-carbon alternatives, suggesting that, without policy adjustments, the market may transition toward near-total reliance on renewable hydrogen in some specific European locations. However, this shift comes with risks related to supply chain stability, technological diversity, and the feasibility of large-scale renewable ammonia production in energy-constrained regions.

5.1.2 Highest and Lowest Performing Countries for Green Ammonia Production

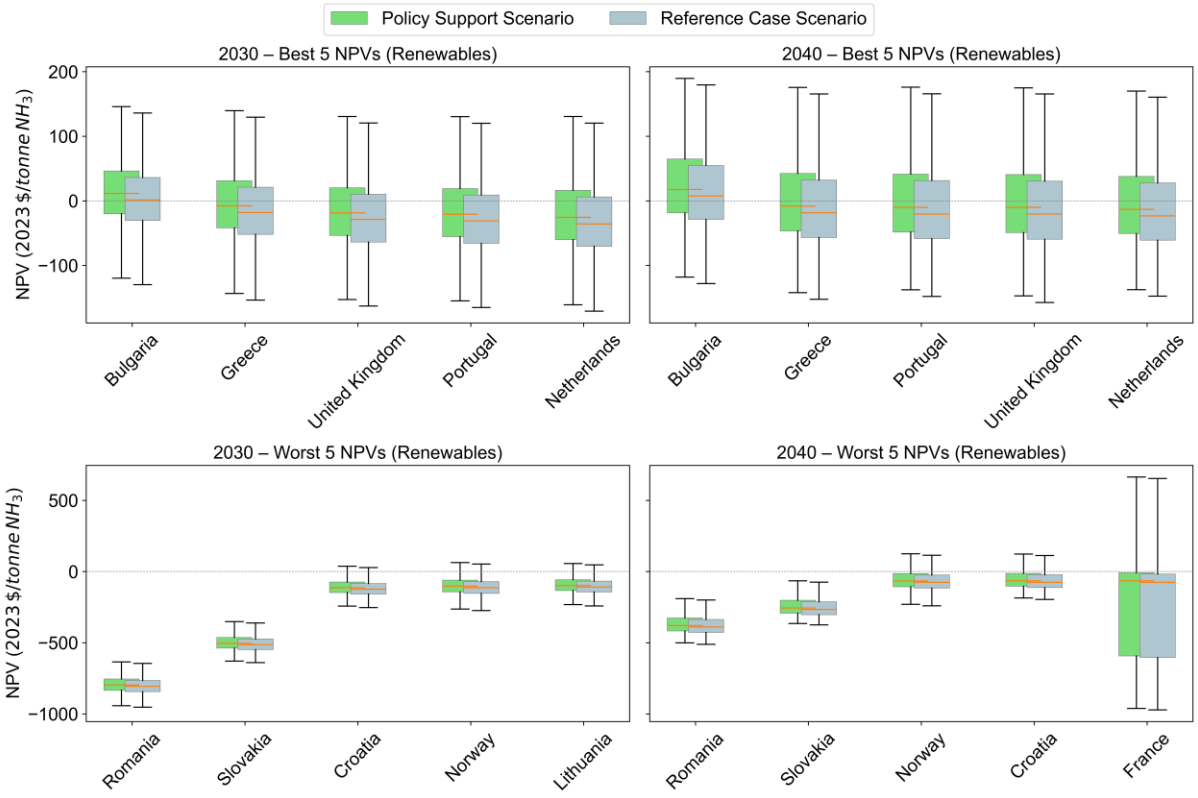
The selection of country locations for green ammonia production is primarily driven by the plant's location and renewable availability, which drives CAPEX and labour costs, which drives OPEX and influences its economics. To illustrate this, as seen in Figure 10, we first analyse the best and worst-performing countries for green hydrogen production, as their relative performance directly impacts ammonia plant economics.

The five best-performing countries in both 2030 and 2040, based on median NPV rankings, are Bulgaria, Greece, the United Kingdom, Portugal, and the Netherlands. While Portugal surpasses the UK in 2040, the difference is minimal, and these five consistently rank as the most favourable locations for green hydrogen production. Conversely, the worst-performing countries in 2030 are Romania, Slovakia, Croatia, Norway, and Lithuania, with France replacing Lithuania in 2040. Additionally, Croatia improves slightly, moving ahead of Norway, though their NPVs remain relatively close in both periods.

A key trend observed is the disparity in NPV spreads between the best and worst-performing groups. Among the best five countries, the gap between the highest and lowest median NPV is less than 50 $/tNH$_3$ in both 2030 and 2040, reflecting a tight range of competitiveness when compared to the range seen for the countries with the lowest NPV values. This suggests that minor differences in policy incentives, infrastructure, or input cost structures could significantly shift rankings within this group. In contrast, for the countries with the lowest median NPV values, the gap exceeds 500 $/tNH$_3$ in 2030. It remains at 350 $/tNH$_3$ in 2040, highlighting more significant economic barriers to competitive renewable hydrogen production in these regions.

Additionally, while moving from RCS to PSS (reflecting the impact of subsidies) improves NPVs, the effect is relatively small compared to the variation between countries. This suggests that policy incentives are unlikely to close the gap between high- and low-performing regions. However, in top-performing countries where NPVs are closely clustered, PSS has a more noticeable impact, as even minor improvements in financial viability can make a difference in investment attractiveness. These findings emphasize that while subsidies help improve economic feasibility, the most significant determinant of success remains the inherent renewable resource availability at existing ammonia locations and cost conditions in each country.

Figure 10: Interquartile range (25th percentile - median - 75th percentile) of the NPV for the five highest and lowest countries in the green ammonia (renewables) pathway



Source: Authors' contributions

5.1.3 Optimal Ammonia Plant Locations for Green Ammonia[26]

Like the country-level analysis in the previous sub-section, selecting optimal locations for green ammonia production is primarily driven by renewable energy availability (which influences CAPEX) and

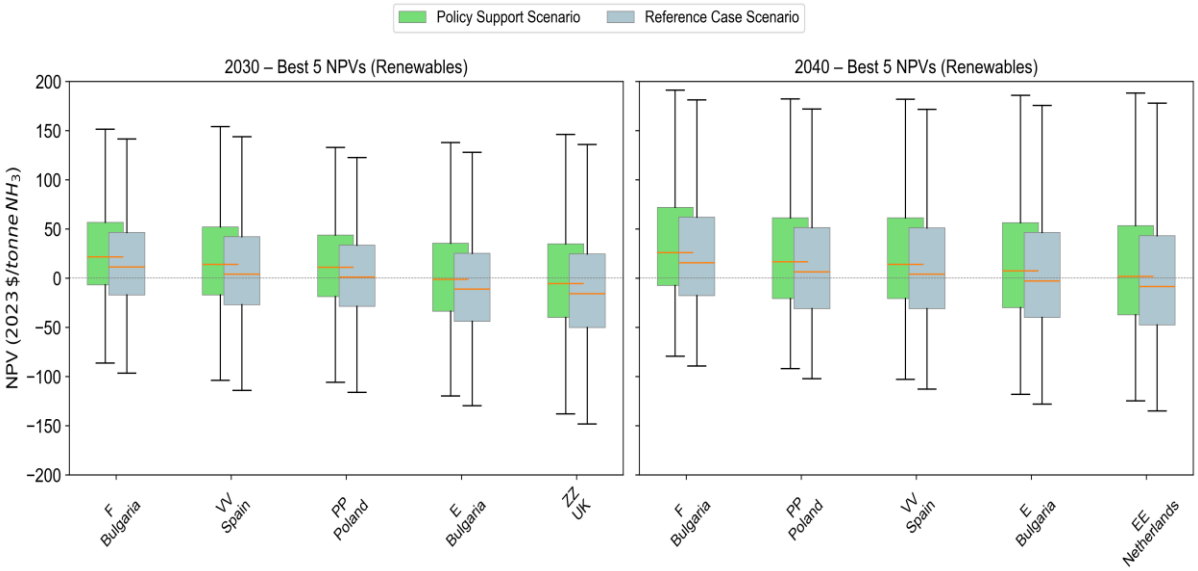
[26] Moreover, our methodology explicitly focuses on optimizing hydrogen production within the constraints of existing facility locations (brownfield sites) rather than selecting new sites based primarily on optimal renewable resource availability (greenfield development).

labour costs (which impact OPEX). While the top-performing sites remain broadly consistent between 2030 and 2040, minor shifts occur as relative cost advantages evolve. A detailed list of these locations in 2030 and 2040 can be found in Table 21 and Table 22 in the appendix. Unlike the previous sub-section, which examined countries as a whole, this section focuses on specific locations within countries, offering a more granular assessment of green ammonia production potential.

As shown in Figure 11, the top five locations for green hydrogen production in 2030 are Bulgaria (F), Spain (VV), Poland (PP), Bulgaria (E), and the United Kingdom (ZZ). In 2040, the ranking remains stable, but Poland (PP) overtakes Spain (VV) for second place, and the Netherlands (EE) enters the top five, replacing the UK (ZZ), which drops to sixth place. These shifts highlight the importance of wind availability for reducing CAPEX, particularly in Poland and the Netherlands, which benefit from strong wind potential.

Bulgaria (F and E) remains the most competitive location for green ammonia production across both years. It ranks first in labour cost competitiveness and fifth in wind availability, among the top three locations for solar availability. This combination allows Bulgaria to maintain consistently high NPV values, particularly as subsidies under PSS enhance its cost advantage further.

Figure 11: Top five locations for the green ammonia (Renewables) pathway in 2030 and 2040



Source: Authors' contributions

Poland (PP) strengthened its position in 2040, surpassing Spain due to its top-ranked wind availability, significantly lowering CAPEX for electrolysis. Although Poland's labour costs are higher than Bulgaria's, they remain well below Western European averages, reinforcing Poland's attractiveness for long-term green ammonia investment. Additionally, a new Polish location (JJ) enters the top 10 in 2040, further signalling Poland's growing competitiveness.

Spain (VV) remains among the top-performing locations, benefiting from the highest solar availability ranking. However, its relative ranking declines in 2040, as Poland's wind advantage outpaces Spain's solar benefits. Spain (XX) also improves but does not break into the top five, indicating that while Spain remains competitive, cost reductions in other regions are more significant over time.

The Netherlands (EE) enters the top five in 2040, reflecting improving competitiveness despite high labour costs. Its strong wind availability ranking (4th overall) allows it to offset some of its higher OPEX, maintaining a viable position among the best locations for green ammonia production. In contrast, the UK (ZZ) experiences a slight decline, primarily due to higher projected labour costs, which reduce its relative advantage over other locations with similar wind availability but lower OPEX burdens.

These results[27] highlight that countries with weaker renewable resources and high labour costs will need alternative strategies, such as hydrogen imports or cross-border infrastructure investment, to remain viable in a decarbonized ammonia market. Indeed, while these results highlight the optimal locations for green ammonia production to meet domestic demand, they also present opportunities for supplying renewable ammonia to neighbouring European countries with weaker renewable resources or higher labour costs, thereby supporting a more integrated and cost-effective hydrogen economy across the region.

5.1.4 Subsidies Required to Match Depreciated SMR Production

Analysing the subsidies required to match depreciated SMR production reveals a wide range of financial support needs across Europe, highlighting the critical influence of local factors such as renewable resource availability, labour costs, and industrial infrastructure requirements. The model's results demonstrate that the subsidy[28] requirement to align renewable-based ammonia production with the cost of untaxed, depreciated SMR under the RCS scenario varies significantly by location, reflecting regional disparities in production feasibility.

At one extreme, a location in Bulgaria (Location F) requires only about 0.077 \$/kg H_2 in subsidies. This extremely low subsidy requirement indicates that the location benefits from robust renewable energy potential and highly favourable labour costs, making it nearly cost-competitive with conventional SMR production even with minimal financial intervention. Specifically, Bulgaria has the lowest labour costs[29] in the EU, ensuring minimal OPEX burdens. Additionally, its renewable availability ranks among the best in our existing ammonia plants list, with top-tier wind availability (5th overall) and strong solar potential (3rd overall), enabling efficient green hydrogen production with lower CAPEX requirements. The combination of low-cost labour and high renewable availability makes Bulgaria's existing ammonia location one of the most competitive locations for conversion to green ammonia production (within the locations we are considering), requiring only modest financial incentives to enhance economic feasibility.

In contrast, a location in France (Location K) demands an exorbitant 106.70 \$/kg H_2 in subsidies. This large subsidy reflects the structural disadvantages of that particular location, which significantly hinder the economic viability of converting that site to green ammonia production. France has one of Europe's highest industry-specific labour costs[30], placing a heavy OPEX burden on hydrogen production. Moreover, the location is suboptimal for renewable energy deployment, with wind availability[31] ranking near the bottom (18.4%) and only moderate solar availability[31] (15.8%) compared to other locations. These conditions necessitate oversized renewable energy installations and additional energy storage capacity to compensate for the low natural renewable output, dramatically increasing CAPEX requirements. The disparity between these two locations stresses the critical role of renewable resource availability and labour costs in determining the economic viability of green hydrogen production.

The per-country averages further illustrate that while some regions – such as specific locations in Poland and Spain – require modest subsidies (approximately 0.43 to 0.47 \$/kg H_2), many locations fall far outside this range. This disparity signals that a one-size-fits-all subsidy approach would be ineffective; targeted, region-specific policy interventions are needed. Financial support should be concentrated in areas where only minimal additional subsidy is necessary to achieve cost parity with SMR. In contrast, regions facing higher structural costs may require broader systemic reforms alongside higher subsidies.

Furthermore, when evaluating the current subsidy level of 0.5 \$/kgH_2, only a small fraction of locations meet the threshold necessary to match the economic performance of depreciated SMR production. Analysis reveals that only about 7% of the evaluated sites – specifically, one location in Bulgaria (Location F), one in Poland (Location PP), and one in Spain (Location VV) – require subsidies of 0.5

[27] Refer to Table 21 and Table 22 for the full rankings and computed NPV.
[28] Refer to Figure 21 and Figure 22 in the appendix for the subsidy and tax behaviour on the median NPV in the model
[29] \$4.0/hour in 2030, rising marginally to \$4.8/hour in 2040
[30] \$59.4/hour in 2030, increasing to \$69.6/hour in 2040
[31] On an hourly-basis throughout the year

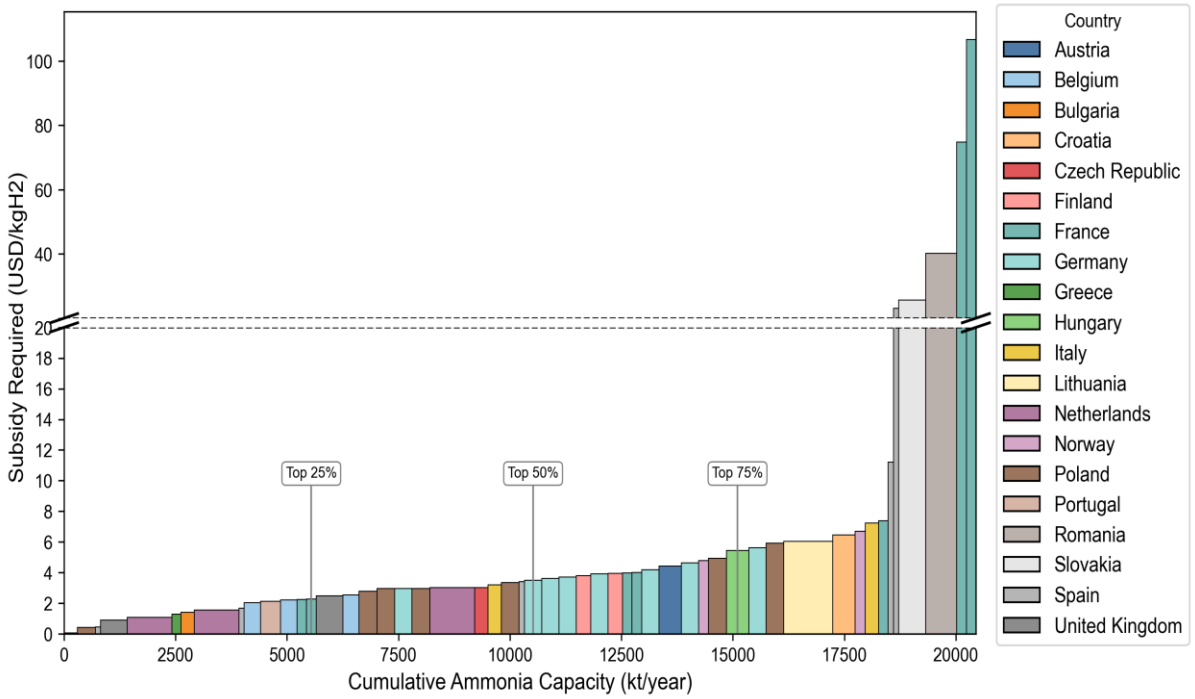
$/kg H_2 or less. The current subsidy alone indicates that only a handful of existing locations would be competitive with existing conventional production. At the same time, the majority would require additional financial support or cost reductions.

Looking at the 52 plants depicted in Figure 12 and Figure 13, we observe the subsidy requirements per location, scaled by cumulative ammonia production capacity ($ktNH_3$/year). This visual highlights the disparity in financial support needed across Europe. The distribution of subsidy needs is highly uneven, with a significant proportion of capacity concentrated in locations requiring minimal subsidies. In contrast, a smaller subset of locations demands exceptionally high financial intervention.

Most production capacity falls within relatively low subsidy requirements, as indicated by the Top 25%, Top 50%, and Top 75% markers. These show that moderate financial support can make a substantial share of existing ammonia production locations viable. However, towards the right side of the distribution, a sharp increase in required subsidies emerges, suggesting that specific locations – those with poor renewable availability and high labour costs – face structural challenges in achieving cost parity with existing SMR production.

Notably, the break in the y-axis underscores the extreme subsidy levels required for the most uncompetitive green ammonia at existing SMR locations, where subsidies required exceed $40–100 $/kg H_2, far above the threshold needed for most other locations. This confirms that a one-size-fits-all subsidy approach would be inefficient, as many locations can become competitive with modest intervention, while others may remain economically unviable without fundamental policy changes at the EU and national levels.

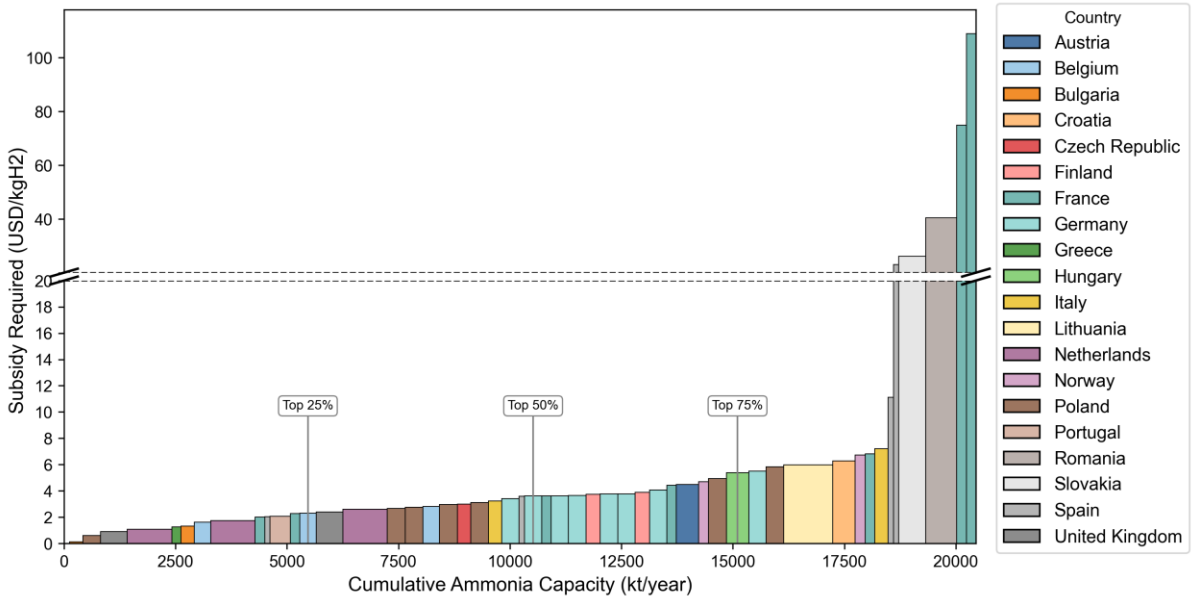
Figure 12: Subsidy required by location for green ammonia production to match existing SMR production in 2030[32]



Source: Authors' contributions.

[32] Assuming capacity of a country is divided equally between plants

Figure 13: Subsidy required by location for green ammonia production to match existing SMR production in 2040



Source: Authors' contributions

Ultimately, these insights emphasize that early deployment of green ammonia should focus on regions requiring minimal subsidies, maximizing the impact of initial investments and accelerating market adoption. Prioritizing such areas provides a blueprint for a cost-effective transition to renewable-based ammonia production. Meanwhile, regions with higher subsidy requirements might consider alternative strategies beyond direct financial support and alternative pathways.

For example, policymakers could implement monthly matching schemes for green hydrogen to smooth out supply and demand fluctuations (we discuss temporal matching in greater detail in Section 5.2, highlighting the substantial difference between hourly and monthly matching). Additionally, broadening eligibility for subsidies to include low-carbon hydrogen pathways – such as CCS-based and biohydrogen – could serve as a transitional solution, enabling these options to compete with conventional SMR-based production until green hydrogen costs decline. A strategic approach for countries like Germany could be to invest in optimal renewable NPV countries in the EU to gain early operational experience with green ammonia and kick-start an EU-centric trade network. This approach reduces dependence on distant imports from places like Chile or Australia. Concurrently, temporarily relaxing certain environmental regulations around low-carbon hydrogen (CCS and bio-H2) at home could accelerate near-term decarbonization efforts. Combined with clustering renewable ammonia production in naturally competitive locations, these targeted policy adjustments can drive down overall costs, spur innovation, and ensure a smoother transition across Europe.

Indeed, an alternative strategy for countries with existing ammonia production facilities that are not optimally located is to invest in rertorfitting these facilities with CCS or $BIOH_2$ equipment.

Retrofitting CCS to an existing SMR plant can significantly reduce capital costs compared to building a new SMR with CCS. Studies indicate that adding CCS to an existing ammonia plant costs only about 20% of the original plant's investment – in one example, ~$335 million to retrofit CCS on a plant that cost $1.675 billion to build [101]. In other words, 80% of the original capital expense is saved by leveraging the existing SMR infrastructure. This makes retrofits a cost-effective decarbonisation strategy for Europe's current ammonia facilities. The IEA notes that it is often "more cost-effective to retrofit CCUS to existing facilities than building new capacity with alternative technologies" in the industry since one avoids high greenfield investment [102].

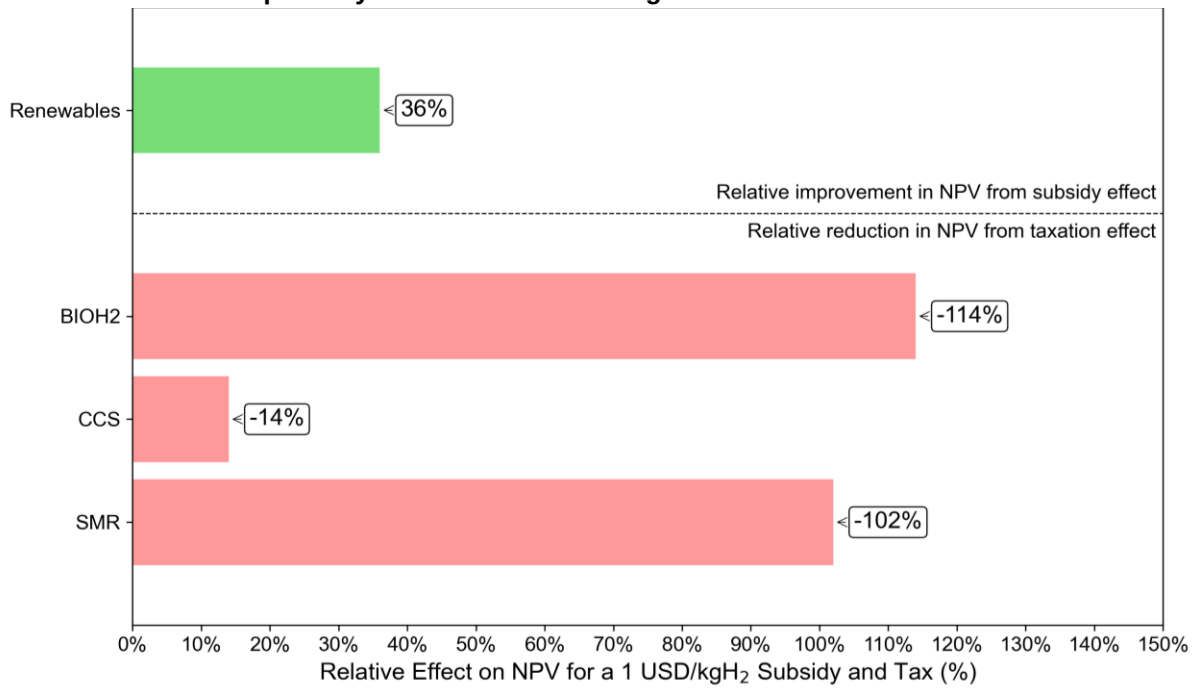
As for retrofitting SMR with gasification units for biomass feedstocks. Greenfield biomass-to-ammonia plants are capital intensive, with a capital intensity of around $2,300–4,500 per tonne of annual

ammonia capacity for plant sizes of 5–150 kton/yr [103]. In contrast, a retrofit must only add the gasifier and integration equipment, avoiding duplicate investment in the ammonia synthesis loop and infrastructure. While exact figures vary, a retrofit might require roughly 50 to 66% of the CAPEX of a comparable new-build plant (depending on how much of the existing plant can be utilised). For example, one techno-economic study found an optimised biomass-to-ammonia design (indirect gasifier + SMR) with an investment of ~€316 million for the retrofitted plant [104].

5.1.5 Subsidy and Carbon Pricing Effects on NPV

On average, over the two-year points, the comparative impact of subsidies and carbon pricing on the NPV of different ammonia production pathways reveals stark differences, as shown in Figure 14. For renewable ammonia, a subsidy of 1 $ per kilogram of hydrogen, on a European average, improves its NPV by approximately 36%. This substantial enhancement demonstrates that targeted subsidies can significantly boost the economics of renewable ammonia, helping close the cost gap with conventional production methods. However, as mentioned earlier in the text, an exclusive focus on only allowing renewable ammonia eligible for subsidies raises concerns about overdependence on a single technology, which may stifle innovation and limit the development of other low-carbon alternatives.

Figure 14: Averaged relative effect of subsidizing or taxing the equivalent of $ 1/kgH_2 on the NPV for the different pathways in the considered region



Source: Authors' contributions

Conversely, carbon pricing exerts a pronounced negative effect on more carbon-intensive pathways. Taxing the equivalent of 1 $ per kilogram of hydrogen – approximately 61.6 $ per tonne of CO_2 – reduces the NPV of SMR-based ammonia production by about 102%. This dramatic change reflects the high carbon intensity of SMR processes and highlights the heavy financial burden imposed on fossil-based technologies. For CCS ammonia, the same carbon price results in a more modest 14% reduction in NPV, indicating that while carbon capture mitigates some tax-related costs, the benefits are limited by emissions from upstream processes. Meanwhile, $BIOH_2$ ammonia is even more adversely affected, with its NPV declining by approximately 114%, underscoring the significant economic challenges due to high supply chain emissions.

These contrasting effects illustrate a clear policy-driven divergence: while modest subsidies can substantially improve the competitiveness of renewable ammonia, even relatively small carbon prices can severely penalise other low-carbon options, such as biomass-based pathways. Notably, the relative

magnitude of the NPV effect from pricing is much larger than the corresponding subsidy effect – demonstrating that these policy tools are not one-to-one. This discrepancy poses a risk of over-penalising carbon-intensive technologies, undermining their advantage vis-à-vis potential imports (see Section 5.3), while under-subsidizing domestically produced low-carbon alternatives, potentially leading to an imbalanced and uncompetitive European production where only a narrow set of technologies and import sources are favoured.

If current policy measures persist, renewable ammonia will increasingly dominate in some existing locations as the favoured option for decarbonising ammonia production. However, by channelling support exclusively to renewable ammonia, other promising low-carbon technologies – such as CCS and $BIOH_2$ – may be deprived of necessary financial incentives, thereby stifling innovation and reducing overall technological diversity within the sector. Such an energy-agnostic approach is essential for ensuring resilience against supply chain disruptions and promoting a robust, multi-technology transition.

Overall, the analysis demonstrates that while a 1 \$/kg H_2 subsidy can boost the NPV of renewable ammonia by roughly 36%, applying an equivalent financial magnitude as a carbon price can reduce the NPVs of $BIOH_2$ by 114%, CCS by 14%, and SMR by 102%. This asymmetry highlights the critical need for a balanced, technology-neutral policy framework, especially considering potential low-carbon imports. Such a framework should support a diverse portfolio of low-carbon ammonia production technologies to ensure a resilient and sustainable transition across the industry while avoiding the pitfalls of over-penalising and under-subsidising key technologies.

5.2 Impacts of Time Matching Requirements on Renewable Production

In transitioning to renewable-based ammonia production, ensuring that the energy supply aligns with the continuous demand of ammonia plants presents a significant technical and economic challenge. This sub-chapter examines the impacts of time-matching requirements on renewable production, investigating how different temporal strategies affect the NPV of renewable ammonia systems. Specifically, our analysis compares the outcomes of hourly matching – where renewable generation and storage capacities are precisely calibrated to meet demand on an hour-by-hour basis – with monthly matching, which offers greater temporal flexibility and eliminates the need for large battery systems, thereby reducing investment costs. Moreover, we explore the potential of a hybrid matching strategy, wherein the renewable ammonia plant is sized based on a monthly matching regime and supplemented with electricity from the grid to achieve hourly matching. This approach is assessed across various European countries to determine its feasibility.

5.2.1 Hourly and Monthly Matching

Examining the renewable production pathway under time-matching requirements – excluding carbon pricing and subsidy effects – reveals that transitioning from monthly to hourly matching imposes a significant financial penalty on green ammonia projects. The analysis, presented in The graph highlights that meeting hourly demand constraints requires significant investment in renewable generation and storage capacity compared to monthly matching, leading to a significant NPV reduction across all countries. However, the magnitude of the impact varies considerably, reflecting differences in renewable resource variability and local energy conditions at existing plant sites. Also, in our earlier analysis, a subsidy of 1 \$ per kilogram of hydrogen improved renewable ammonia's NPV by approximately 36% on a European average. In contrast, the NPV reduction from switching to monthly matching starts by halving the NPV for the best locations and reducing the value by 21 times at the worst existing locations. This observation suggests that adjusting or relaxing hourly matching requirements – or adopting hybrid matching strategies beyond traditional financial incentives (carbon pricing and subsidies) – could be an effective, non-financial mechanism to enhance the investment-grade profile of green ammonia projects.

Countries with stable and complementary renewable generation profiles – such as Bulgaria, Greece, and the UK – experience relatively lower NPV reductions, with median reduction multiples ranging from -1.0 to -1.7 in 2030 and improving further in 2040. This result suggests that the cost penalty of hourly matching in these locations is more manageable due to a better balance of wind and solar resources, reducing the need for excessive overcapacity or storage investments. Figure 15, illustrates the relative reduction in NPV when switching from a monthly to an hourly matching regime, quantified as a median reduction multiple for each country in 2030 and 2040.

The graph highlights that meeting hourly demand constraints requires significant investment in renewable generation and storage capacity compared to monthly matching, leading to a significant NPV reduction across all countries. However, the magnitude of the impact varies considerably, reflecting differences in renewable resource variability and local energy conditions at existing plant sites. Also, in our earlier analysis, a subsidy of 1 $ per kilogram of hydrogen improved renewable ammonia's NPV by approximately 36% on a European average. In contrast, the NPV reduction from switching to monthly matching starts by halving the NPV for the best locations and reducing the value by 21 times at the worst existing locations. This observation suggests that adjusting or relaxing hourly matching requirements – or adopting hybrid matching strategies beyond traditional financial incentives (carbon pricing and subsidies) – could be an effective, non-financial mechanism to enhance the investment-grade profile of green ammonia projects.

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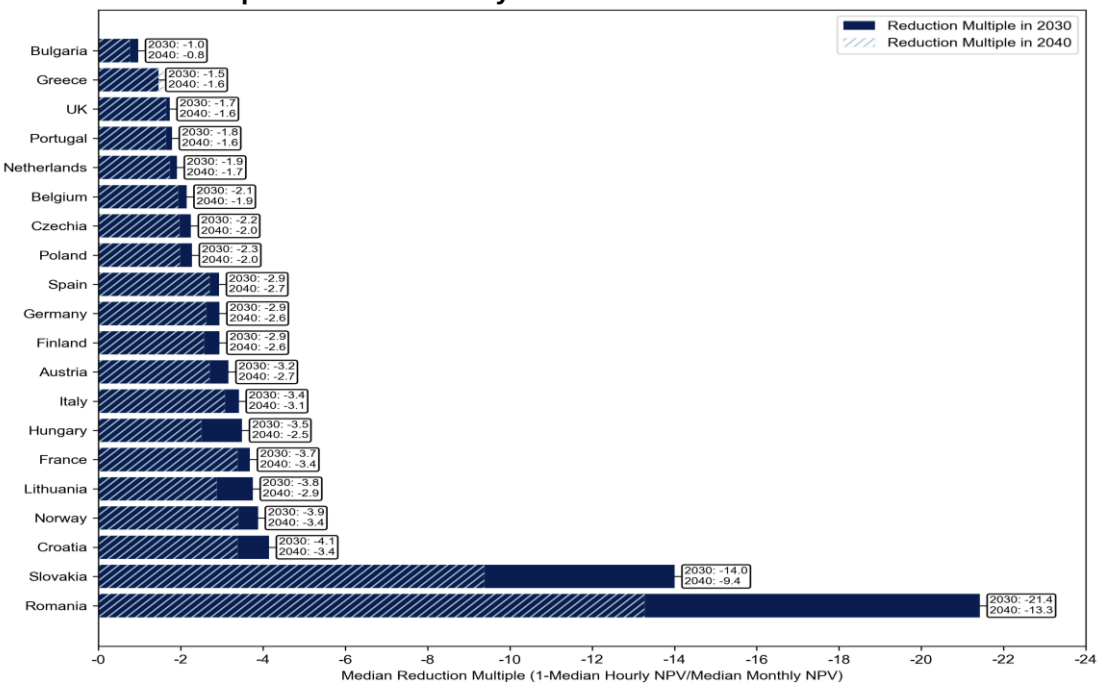
Figure 15: Relative NPV reduction when switching from monthly to hourly matching, shown as median reduction multiples for each country in 2030 and 2040[33]



Source: Authors' contributions

Conversely, existing SMR sites with lower renewable potential, higher intermittency, and less flexibility in generation – such as those in Croatia, Slovakia, and Romania – see dramatic improvements in NPV when shifting to monthly matching. Slovakia and Romania stand out, with NPV reductions exceeding –21 in 2030 and remaining high even in 2040 (-13.3 and -9.4, respectively). This indicates that hourly matching in these locations and countries creates excessive CAPEX requirements, forcing significant overinvestment in renewables and storage to meet demand at all times.

A clear trend of improvement between 2030 and 2040 is observed in most countries, with reduction multiples generally becoming less severe over time. This aligns with technological advancements in

[33] Reduction multiples seen in the box connected to each bar chart is representative of the reduction multiple in the specific year when going from monthly to hourly matching

electrolysers, battery storage, and renewable electricity generation, which lower overall costs. However, even in 2040, the financial burden of hourly matching remains substantial, often surpassing the impact of subsidy support.

This observation suggests that adjusting or relaxing strict hourly matching requirements – or implementing hybrid matching strategies (see Section 5.2.2) – could be an effective non-subsidy mechanism to enhance the financial viability of green ammonia projects. By allowing for greater operational flexibility, including potential grid supplementation during periods of low renewable output, policymakers could reduce the need for excessive capital investment without direct financial support. Ultimately, these findings underscore the need for a balanced approach between financial incentives, environmental regulation and operational flexibility, ensuring that green ammonia production remains economically competitive and scalable.

5.2.2 Potential of Hybrid Matching Across Europe

The potential of hybrid matching across Europe shows that a renewable ammonia plant can rely extensively on in-situ renewable generation, supplemented by grid electricity – provided the grid is allowed under a more flexible matching regime rather than a strict hourly 90% clean requirement. Figure 16 and Figure 17 illustrate the results for 2030 and 2040, highlighting how many operational hours are covered by on-site renewables and how clean grid availability can further reduce fossil reliance.

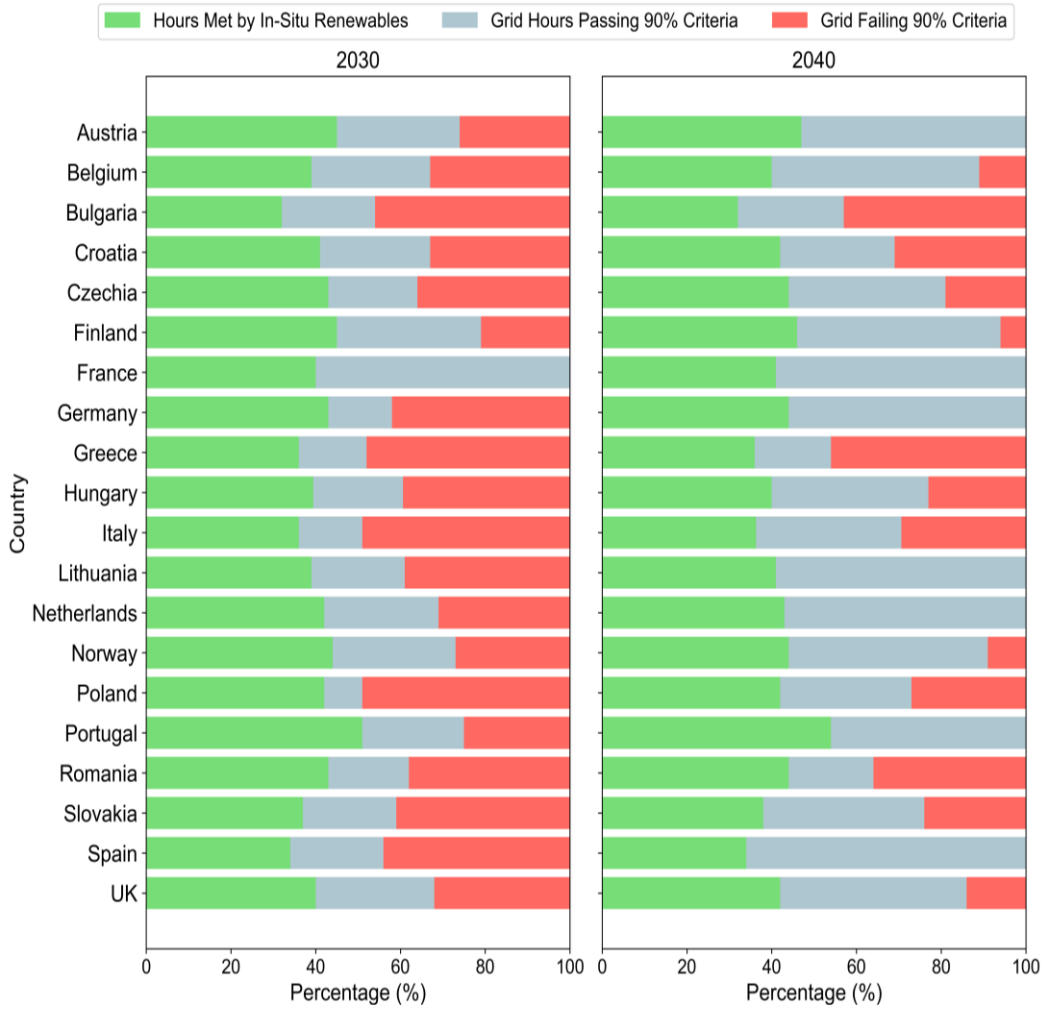
In Figure 16, renewable capacity is sized based on monthly matching, yet we still apply an hourly matching rule to determine the share of hours that meet the 90% threshold with that capacity. Under this design approach, Portugal achieves the highest “Hours Met by Renewables” in 2030 at 51%, followed by Finland and Austria (both 45%). By 2040, Portugal again leads at 54%, with Austria at 47% and Finland at 46%. Conversely, Bulgaria (32%), Spain (34%), and Italy (36%) occupy the lower end of on-site renewable coverage in 2030, reflecting limited solar or wind resource availability. If these countries aimed for strict hourly matching, they would face steep capital costs for storage or significant overbuilding of renewables to ensure uninterrupted low-carbon power.

The cleanliness of the grid also varies markedly. In 2030, Spain exhibits the highest “Hours Met by Clean Grid Connection” at 66%, while Poland lags at 9%. By 2040, Austria improves to 49%, and Spain remains strong at 61%, while countries like Norway (31%) and Italy (64% in 2040, up from 50% in 2030) showcase diverse trajectories for grid decarbonisation. Despite incremental progress, some regions – e.g., Bulgaria – still grapple with reliance on fossil-based electricity, creating challenges under a 90% clean electricity standard.

It is important to note that the monthly-based capacity design does not directly optimize for hourly fluctuations; therefore, the “best” performers under this framework (Portugal, Austria, Finland) may differ from countries ranked highly in earlier hourly-focused evaluations (Sections 5.1.2 and 5.1.3). Even so, robust renewable resources remain advantageous, whereas weaker clean energy potential or slower grid decarbonisation places other locations at a relative disadvantage.

From what is stated earlier in this subsection, we can observe an opportunity for a potential hybrid matching approach to provide a practical solution to a seemingly over-encumbering issue with the requirements for hourly matching. This framework for a hybrid matching strategy consists of two key elements: (A) sizing renewables based on monthly matching optimisation, which enables earlier project deployment, improves economics and aligns with the pre-2030 European matching rule of monthly-based accounting, and (B) incorporating national grid decarbonisation targets instead of a static 90% clean threshold, allowing projects to benefit from their country’s planned grid improvements rather than being constrained by a rigid, Pan-European one-size-fits-all rule. By combining these two factors, hybrid matching facilitates greater flexibility, avoids cliff-edge policy effect (retaining monthly matching rule before and after 2030), reduces the need for excessive overbuilding of renewables capacity, and enables smoother integration of renewable ammonia production into evolving energy systems.

Figure 16: Electricity supply breakdown for renewable ammonia production in terms of in-situ generation, 90% clean grid compliance, and non-compliant hours for 2030 and 2040[34]



Source: Authors' contributions

A hybrid matching strategy offers relief by letting projects tap into national electricity market developments for 2030 and 2040 rather than relying on a uniform 90% clean threshold. Under this approach, countries draw on grid electricity aligned with their decarbonisation pathways, lowering the need to overbuild renewables or invest heavily in storage and relieving pressure on the competition for renewable capacity. Nations with ambitious plans for renewable expansion, nuclear growth, or other clean thermal technologies (e.g., biomass or BECCS-equipped plants) can thus achieve a sharp increase in the share of low-carbon electricity hours – often enough to eliminate or substantially reduce hours failing to meet clean power requirements.

Figure 17 presents the outcomes of this strategy. It shows the percentage of hours met by on-site renewables and clean grid electricity and the share of hours failing to meet a national clean target. Many countries, such as Belgium and Bulgaria, register 0% failing hours in 2030 under their projected grid mix – suggesting they expect enough offshore wind, biomass, or decarbonized thermal to meet low-carbon goals. By 2040, a few countries see a modest uptick in failing hours. For instance, Belgium rises from 0% failing hours in 2030 to 18% by 2040, while Norway's failing hours increase from 19% to 25%.

[34] Full data on in-situ grid hours and hours failing to pass the 90% criteria are found in Table 23in the appendix.

Paradoxically, these setbacks occur despite increasing renewables targets – as in the case of Belgium and Norway – as the average carbon intensity of the grid does not drop as swiftly as the renewable share rises. Upstream biomass emissions and nuclear fuel upstream emissions can prevent overall grid emissions from declining in step with new renewable capacity. As a result, the average reduction in emissions intensity lags behind the trajectory implied by renewables-only metrics. Indeed, this trend is not observed if we discard upstream emission accounting for biomass and nuclear based electricity.

Figure 17: Electricity supply breakdown for renewable ammonia production in terms of in-situ generation, national target clean grid compliance, and non-compliant hours for 2030 and 2040[35]

Source: Authors' contribution

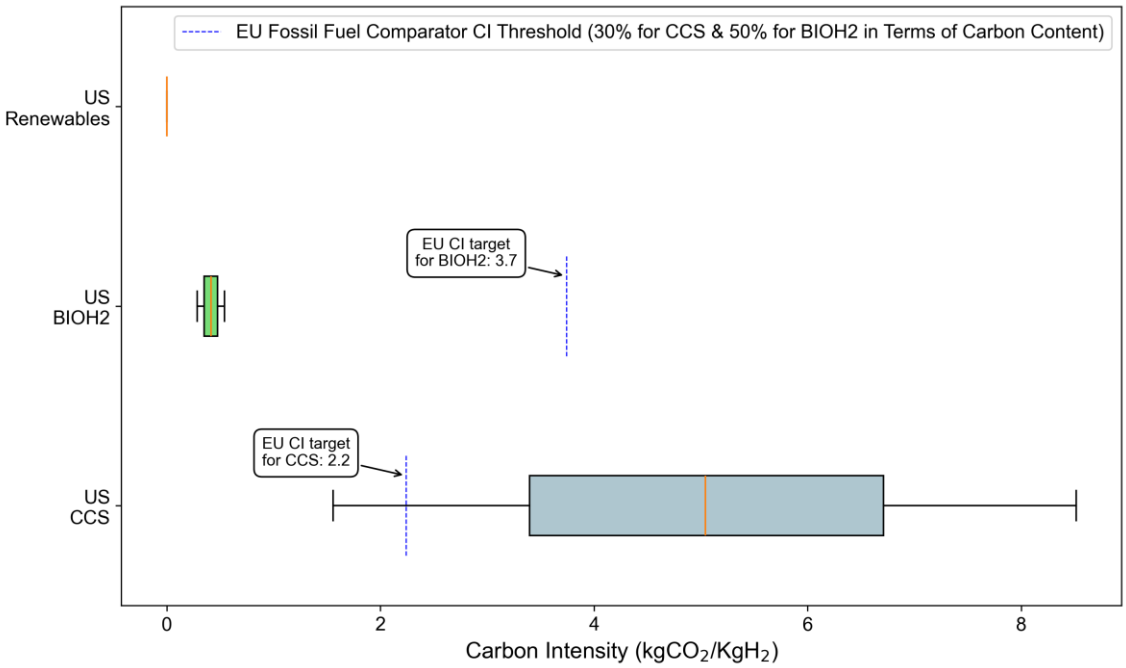
Nevertheless, even with these nuances, by 2040, most European grids approach or surpass 90% clean power, demonstrating that hybrid matching is ultimately a transition mechanism. In the near term, it provides green ammonia projects with a viable route to meeting decarbonization targets without excessive capital outlays for storage or renewables overcapacity. By 2040 and beyond, these projects can more readily achieve a strict 90% clean requirement on the grid alone as national energy mixes move close to being carbon-free and the need for flexible hybrid policies steadily diminishes.

[35] Full data on in-situ grid hours and hours failing to pass the national targets are found in Table 24 while specific grid fuel sources for 2030 and 2040 for each country can be found in Table 25, both of which in the appendix.

5.3 Transatlantic Ammonia Trade under Regulatory Constraints

The analysis of imported US-based ammonia production—across CCS, $BIOH_2$, and renewable pathways—within the European regulatory framework reveals the following insights, as shown in Figure 18. By comparing the carbon content of US-produced ammonia with European CI thresholds and applying the carbon accounting methodology used in this report, we assess compliance with the target thresholds set under RFNBO, LCF, and RED III-Biofuels. To qualify as 'clean' hydrogen—and by extension, clean ammonia—hydrogen must have a carbon content of 30% or less for CCS and renewables and 50% or less for $BIOH_2$ within European threshold requirements, provided that nitrogen is sourced from the air. Our evaluation shows that only the most environmentally stringent CCS production would qualify for certification, whereas $BIOH_2$ and renewables would meet their respective thresholds without any issues[36].

Figure 18: Carbon intensity comparison of US ammonia production pathways against the European SMR benchmark



Source: Authors' contributions

This finding is significant, as US ammonia produced via CCS, $BIOH_2$, or renewable-based methods could qualify as low-carbon and be eligible for entry into the European market under CI thresholds, CBAM, and RED III constraints. As a result, US low-carbon ammonia is well positioned to meet European CI criteria, potentially enabling a viable transatlantic trade in clean ammonia.

Notably, importing low-carbon hydrogen from biomass in the US is a more favorable option than importing raw biomass and producing hydrogen in Europe. The latter approach faces higher supply chain emissions under EU regulations, as the transport and processing of biomass within Europe would be subject to stricter life-cycle assessment (LCA)-based emissions accounting.

Conversely, under ETS rules for international shipping, imported hydrogen can bypass 50% of the emissions costs incurred during transport. Meanwhile, CBAM applies emissions calculations only at the point of production rather than across the entire supply chain. This difference in emissions accounting may influence cost competitiveness, as the remaining 50% of shipping emissions are not currently accounted for. In contrast, domestic production is subject to a more comprehensive carbon taxation framework.

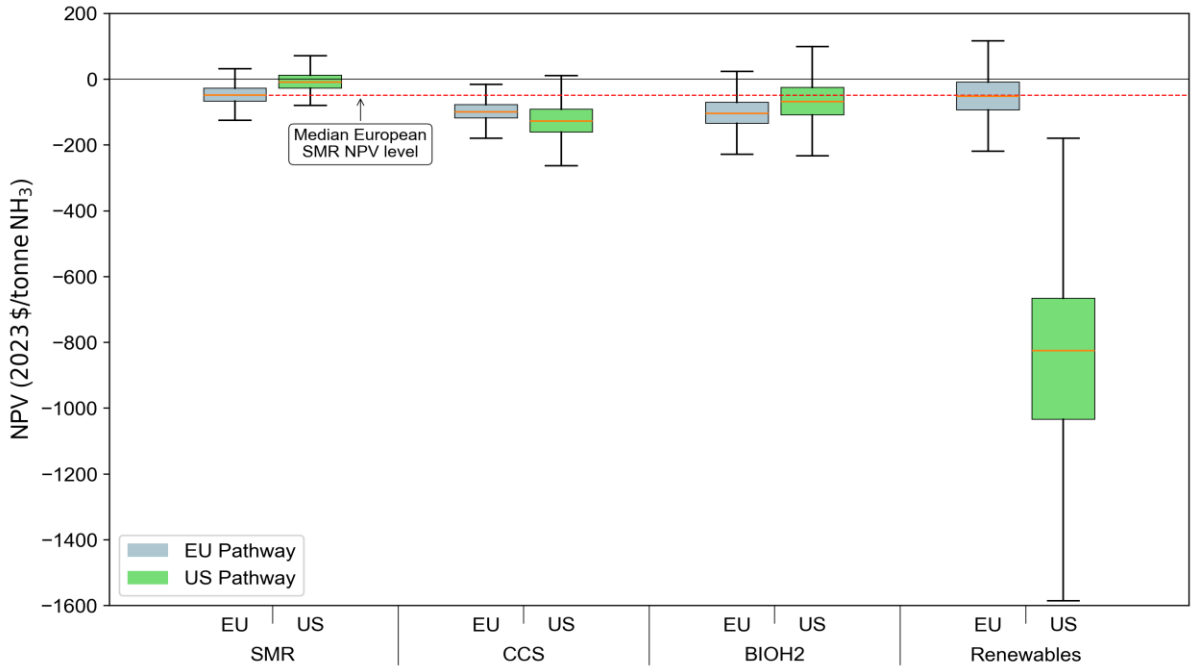
[36] The analysis excludes the impact of international shipping, which could have an impact on eligibility for the different pathways

The partial coverage of international shipping emissions under the ETS and CBAM raises concerns about potential carbon leakage. If the objective of CBAM is to ensure fair competition between imported and domestically produced low-carbon hydrogen or ammonia, then fully accounting for emissions across the supply chain is necessary. Covering only 50% of shipping emissions may create an imbalance in cost structures, as domestic producers in Europe are subject to a more comprehensive carbon taxation system. This discrepancy could incentivize production outside the EU, with subsequent imports re-entering the market under a less stringent emissions accounting framework. Addressing this gap in emissions pricing could help align trade incentives with the CBAM's intended goal of reducing carbon leakage. At the same time, directly importing low-carbon hydrogen from the US may provide a cost advantage, avoiding additional supply chain emissions while supporting a more efficient decarbonization pathway for EU hydrogen consumption. However, investment decisions should not rely on temporary regulatory differences, as policymakers may seek to adjust frameworks to ensure a consistent and comprehensive approach to emissions accounting over time.

Looking ahead, the EU will likely take steps to address any potential regulatory gaps, aiming for a more holistic emissions accounting that includes all components of the supply chain. However, it is still important to note the potential adverse effects of the current partial coverage, as it may influence investment decisions, cost structures, and the broader path of Europe's decarbonization efforts.

Beyond carbon eligibility, we examine the economic feasibility of transatlantic ammonia trade by comparing the NPVs of US ammonia production – using clean hydrogen derived from CCS, $BIOH_2$, and renewables – against European ammonia production under the stated policies scenario (with carbon prices and subsidies), seen in Figure 19 and Figure 20 for 2030 and 2040, respectively. The results indicate that by 2030, US ammonia produced via $BIOH_2$ and CCS is not only competitive with its European counterparts but, in some cases, more economically attractive than even depreciated European SMR-based ammonia. The cost advantage stems from the lower-carbon production processes in the US, which allow these technologies to compete even when benchmarked against a stringent European SMR standard.

Figure 19: Economic feasibility of transatlantic ammonia trade comparing NPV of US and European ammonia production across the considered pathways under PSS policies for 2030

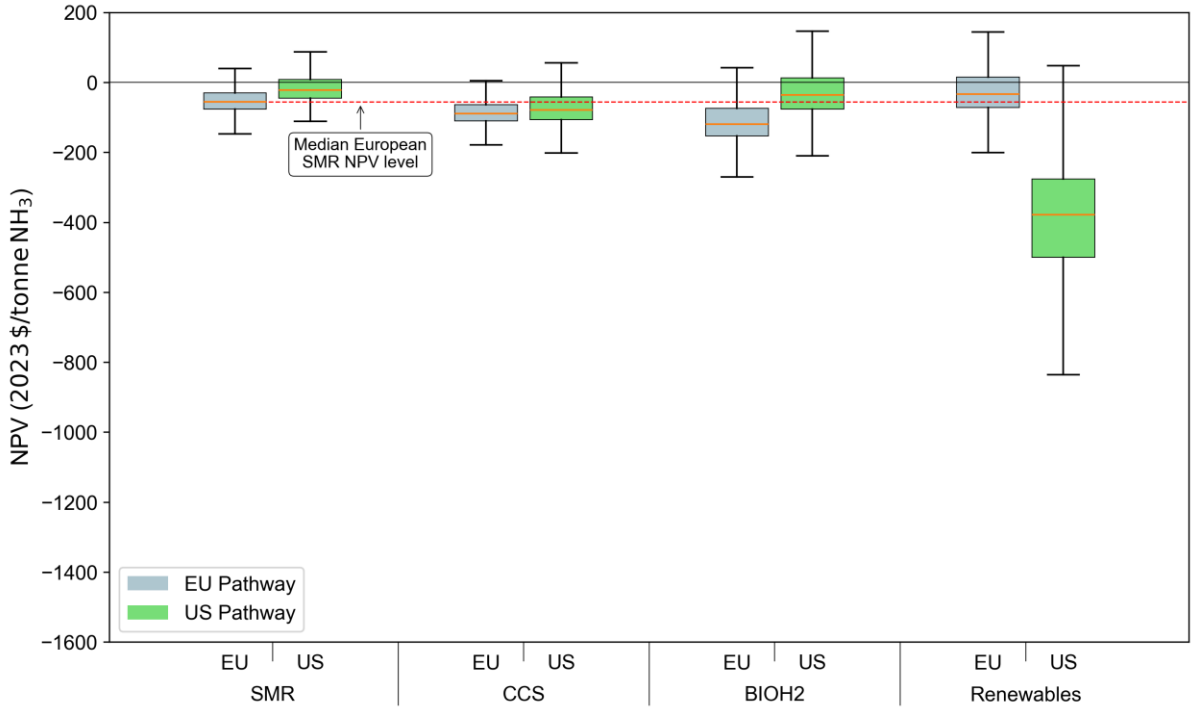


Source: Authors' contributions

For renewable-based ammonia, the situation in 2030 is less favourable, as its NPV remains less competitive. However, by 2040, the financial outlook shifts. The median NPVs for US ammonia

produced using $BIOH_2$ and CCS-based hydrogen climb faster than European SMR production, making US-based low-carbon ammonia increasingly cost-competitive. Even US renewable-based ammonia, previously uncompetitive, starts to show cases where it outperforms its European counterpart. These trends suggest that, under the stated European regulatory framework, US producers could secure a growing share of the European market for clean ammonia as technology costs decline.

Figure 20: Economic feasibility of transatlantic ammonia trade comparing NPV of US and European ammonia production across the considered pathways under PSS policies for 2040



Source: Authors' contributions

To ensure comparability, this analysis assumes an islanded setup for hydrogen and ammonia production in the US, with strict hourly matching, mirroring the European approach to meeting additionality requirements under the RED III Delegated Acts. This methodological consistency ensures that US and European ammonia production is assessed under similar constraints.

However, shipping emissions are not considered in this comparison due to data limitations. Yet, it is important to note that this omission focuses the assessment solely on production emissions, which may influence the perceived competitive positioning of US-based clean ammonia[37]. With that being said, the trade implications are substantial. With US ammonia produced from CCS and $BIOH_2$ pathways competing with or surpassing European ammonia by 2030 and 2040 and US renewable-based ammonia catching up by 2040, US producers are well-positioned to export clean ammonia to Europe under the relevant European regulations and the US IRA.

US clean ammonia meets the carbon content limits imposed by European regulations. It presents a cost-competitive alternative to domestic European production, which faces higher carbon pricing despite supplying the same market. This discrepancy arises as imported US ammonia may be subject to lower carbon taxation than its European counterpart, creating a potential imbalance in market competition.

[37] Emissions from the transportation or distribution of the product, as well as downstream emissions from its use, are not included in the CBAM assessment. Meanwhile, the EU ETS accounts for 50% of international shipping emissions; however, ETS shipping-related emissions are not considered in this study

Moreover, this raises significant policy considerations. While CBAM ensures that imported ammonia faces an equivalent carbon cost to European production, the fact that US clean ammonia is already positioned to be cost-competitive with European counterparts due to assumed strong policy support under the IRA for US-based production, despite strict hourly matching and an islanded setup, suggests that future policy adjustments could further strengthen trade dynamics. However, this also introduces a competitive and geostrategic risk for European ammonia producers, including those relying on subsidised renewable-based production. If US-based low-carbon ammonia continues to gain cost advantages, European producers – despite receiving policy support – could struggle to compete in an increasingly open market to cleaner, lower-cost imports. Balancing the goals of market competition, industrial resilience, and deep decarbonisation will be a crucial challenge for European policymakers as tensions over transatlantic relations rise while trade in internationally liberalised commodity markets expands in the coming decades.

However, the competitiveness of US production relies heavily on the continuation of financial support under the IRA framework, which remains uncertain given the current political landscape in the US. Any policy shifts or rollbacks in support mechanisms could alter the cost dynamics of US-based low-carbon ammonia, potentially reducing its competitive edge in global markets.

Additionally, environmental policies in one jurisdiction – such as Europe's CBAM framework – may catalyse similar policy responses in other jurisdictions, including the US. This regulatory interplay could generate positive spillover effects, reinforcing emissions reductions on both sides of the Atlantic. If US producers seek to align with EU import standards and leverage CBAM-related advantages, it could also accelerate the decarbonization of US hydrogen and ammonia production.

Thus, while US-based production currently benefits from a strong policy framework and lower-cost renewable resources, its long-term viability depends on domestic political stability, exporters' interests in accessing European markets and the evolving geopolitics of international trade and climate policies.

5.4 Limitations

While this study provides a robust economic framework integrating key economic, environmental, and policy variables to assess ammonia decarbonisation pathways and trade feasibility, several limitations should be acknowledged:

Firstly, our analysis incorporates several simplifying assumptions despite efforts to align with regional policy frameworks and energy market conditions. These assumptions include fixed ammonia plant capacities and constant production rates, which do not reflect operational flexibilities achievable through hydrogen-based storage, plant-specific efficiency variations, or economies of scale, potentially influencing real-world feasibility.

Secondly, emissions from international shipping and inland transport were not explicitly modelled due to limited data availability. This omission creates a limitation, particularly given the partial accounting of international shipping emissions under the current EU ETS, which covers only 50% of these emissions. At the same time, CBAM calculates emissions strictly at the point of production. Not considering specific supply-chain emissions, including international shipping and inland transport within Europe, may result in an incomplete assessment of import competitiveness. Addressing this limitation in future iterations would offer greater accuracy and insights into market dynamics.

Additionally, the current analysis assumes a linear correlation between natural gas prices and ammonia sales revenue—a historically reasonable assumption. However, market evolution could alter this dynamic, particularly as ammonia markets increasingly decouple from fossil-fuel-based pricing structures.

Our study evaluates ammonia production under two specific policy scenarios (RCS and PSS), yet considerable regulatory uncertainties remain. Notably, the LCF carbon accounting methodology is still in draft form, and RED III's criteria for $BIOH_2$ explicitly apply only to transport fuels, not ammonia production. Such regulatory uncertainties could significantly shift the economic landscape for ammonia trade and must be addressed in future research.

Also, in order to maintain consistency across the diverse pathways examined, this analysis employs a self-defined carbon accounting methodology. This approach ensures comparability among different

production routes; however, it introduces certain limitations with respect to the EU's evolving carbon methodologies and the pathway-specific requirements that may arise once the methodologies are finalized. Consequently, while our internal framework provides a coherent basis for assessing ammonia production pathways, it may not be fully aligned with the eventual criteria or metrics once they are definitively established.Another limitation relates to ammonia demand projections. Our study assumes ammonia will continue to be a critical component of European industrial and agricultural applications. However, demand may vary significantly due to technological advances, market shifts, or regulatory changes, creating uncertainty around future market dynamics and the scale of necessary policy support.

Moreover, future studies could benefit from examining a specific local production project alongside a project aimed at importing clean ammonia into the EU. By applying the different pathways assessed in this report and compiling, accounting for, and analysing the relevant regulatory frameworks for both domestic and imported ammonia, deeper insights could be gained into the comparative advantages and policy implications that influence investment decisions—as well as whether there are any carbon accounting gaps or risks of double counting.

Finally, our analysis does not explicitly consider variations in demand timing or market flexibility, which could influence economic viability and operational strategies. Recognising this limitation, we propose it as a valuable area for future research to improve market understanding and refine strategic decision-making.

Despite these limitations, this study provides a robust framework for integrating key economic, environmental, and regulatory variables relevant to ammonia decarbonization and trade feasibility. However, interpretations of the findings should remain mindful of the assumptions and constraints discussed above.

6. Implications for Industry and Policy Stakeholders

This section outlines key takeaways for policymakers, industry leaders, and investors based on the findings of this research. The analysis highlights the role of subsidies, carbon pricing, time-matching requirements, and trade competitiveness in shaping the future of the European ammonia market. It also recommends a cost-effective and resilient transition toward low-carbon ammonia production while maintaining European industrial competitiveness in a changing global market.

6.1 Balancing Carbon Pricing and Subsidisation to Ensure a Level-Playing Field

The analysis highlights a critical policy imbalance: carbon pricing has a much stronger negative effect on NPV than the positive effect of subsidies. A 1 \$/kg H_2 subsidy improves the NPV of renewable ammonia by 36%, whereas carbon pricing the same amount reduces the NPV of $BIOH_2$ by 114%. This disproportionate impact risks over-penalising specific low-carbon options while failing to incentivise others sufficiently.

Policymakers should reassess the balance between pricing and subsidization. While carbon pricing is necessary to drive decarbonisation, it must be complemented by sufficient financial support to ensure viable alternatives. Under-subsidising clean hydrogen pathways while heavily penalising (via carbon pricing) fossil-based low-carbon options could lead to an uncompetitive market where investments stagnate, resulting in an overreliance on a single production pathway.

6.2 Expanding Policy Support Beyond Renewable Hydrogen

Current EU policy exclusively supports renewable-based ammonia through subsidies, while low-carbon alternatives such as CCS-based ammonia and $BIOH_2$ receive no financial support. However, in our analysis, neither CCS nor $BIOH_2$ meets their respective EU CI thresholds. Nonetheless, there is a case for these technologies to serve as transitional, lower-cost solutions, particularly for production facilities with limited renewable availability.

This exclusion presents a risk: the ammonia sector could become overly reliant on overseas imports or on a single production pathway – renewable ammonia – while stifling innovation in other low-carbon technologies. A more inclusive policy framework could provide tiered incentives based on emissions

reduction potential rather than a binary subsidy structure that only supports renewable ammonia. For example, a subsidy structure that scales with emissions reductions could enable a broader set of low-carbon technologies to contribute to ammonia decarbonisation while ensuring cost competitiveness in the short term.

Moreover, low-carbon hydrogen options such as CCS and $BIOH_2$ can play a crucial role as transitional solutions, supporting the early scaling of hydrogen infrastructure. By leveraging existing infrastructure and supply chains, these pathways can help bridge the gap until green hydrogen costs decline sufficiently through learning curves, economies of scale, and infrastructure maturity. Without this intermediate support, green hydrogen deployment may be slower and more expensive, as infrastructure investment could be delayed (or require much higher upfront public support – see the current discussion regarding the German's cost allocation approach to finance hydrogen infrastructure) due to the lack of an initial hydrogen demand base.

Thus, incorporating low-carbon options as transitional pathways would support short-term decarbonisation and lay the groundwork for a more cost-effective green hydrogen economy in the long term. A more technology-neutral approach to policy incentives would provide greater flexibility, reduce investment uncertainty, and accelerate the overall hydrogen market transition while ensuring that future green hydrogen production benefits from a pre-established, cost-efficient infrastructure network.

6.3 Prioritising Green Ammonia Production in the Most Cost-Effective Locations

The analysis of optimal green ammonia production sites reveals that existing sites in Bulgaria, Spain, and Poland offer the most attractive NPVs, primarily due to substantial renewable energy availability and low labour costs. By contrast, existing sites with low renewable potentials and high opex costs, such as those in countries like Germany, the Netherlands, and Austria, remain uncompetitive for renewable ammonia production, even with subsidies.

Given the limited availability of financial support, policymakers should prioritise investments in regions where subsidies have the highest impact on cost competitiveness at existing SMR locations. Early deployment in low-cost sites such as those in Bulgaria and Spain can serve as a springboard for efficiently scaling the green ammonia market. Meanwhile, higher-cost sites may require alternative incentives, such as infrastructure investment in retrofitting existing depreciated production facilities with CCS, to save costs and avoid the CAPEX burdens of new construction.

6.4 Reevaluating and Adopting a Flexible Approach to Hourly and Hybrid Matching

To accelerate the deployment of renewable ammonia projects across Europe while ensuring economic viability and alignment with national decarbonisation goals, policymakers should adopt a flexible hybrid matching approach that balances renewable generation, grid integration, and evolving national electricity markets. This policy framework will support the transition towards low-carbon industrial production by enhancing grid flexibility, reducing excessive capital investments in energy storage, and facilitating a phased approach to clean energy compliance.

A key aspect of this approach is adopting a monthly-based renewable sizing strategy. Renewable ammonia facilities should be allowed to size their renewable energy capacity based on monthly generation patterns rather than constrained by rigid hourly matching requirements. This enables earlier project deployment, reduces unnecessary overcapacity, and aligns with the pre-2030 European standard of monthly-based matching, avoiding cliff-edge policy effects and reducing competition for limited renewable resources. National energy regulators should provide guidelines and incentives for companies to optimise their renewable capacity investments based on monthly renewable energy assessments.

Another critical element is incorporating national grid decarbonisation pathways. Instead of enforcing a static 90% hourly clean energy threshold, projects should be permitted to meet their electricity needs based on the national grid's planned decarbonisation trajectory. This ensures that industries can integrate into evolving energy systems without facing prohibitive storage or overbuilding costs. Policymakers should establish country-specific benchmarks for clean electricity procurement, allowing companies to source grid electricity that aligns with projected national clean energy shares for 2030 and 2040.

This policy will reduce costs and enhance the market competitiveness of renewable ammonia production by eliminating the need for excessive overbuilding of renewables or energy storage. It will optimise grid integration by encouraging industries to leverage clean grid electricity in alignment with national decarbonisation pathways, supporting the broader energy transition.

6.5 Strengthening the Competitiveness of European Ammonia Producers in International Trade

The transatlantic ammonia trade analysis shows that by 2030, US-based $BIOH_2$ and CCS ammonia could already be competitive with their European counterparts, including the depreciated SMR. By 2040, all US clean ammonia pathways – including renewables – become more cost-competitive on a median basis than European production.

This raises concerns for European ammonia producers, including those relying on subsidized renewable production. If US ammonia gains cost advantages under the assumed continuation of the IRA policy support framework, European producers may struggle to compete, even with policy support.

Policymakers must balance regulatory mechanisms to ensure fair competition without undermining domestic ammonia production. Potential options include introducing targeted financial support for European producers, implementing trade adjustment measures to ensure imports receive equitable treatment compared to local production—thus creating a level playing field (e.g., incorporating supply chain emissions; see §6.6 below)—and/or strengthening infrastructure investment to reduce European production costs.

6.6 Clarifying the Role of Shipping Emissions in Carbon Accounting

The analysis in this report does not account for shipping emissions. However, these emissions are partially addressed through the ETS, which currently covers 50% of international shipping emissions—an aspect not captured in this study's results. As a consequence, US-based ammonia imports appear to present a more attractive investment option. Yet, if future regulations mandate a more comprehensive accounting of shipping emissions beyond the current 50% coverage under ETS, the competitive landscape could shift markedly. Establishing long-term regulatory frameworks that ensure equal treatment and harmonization between imports and domestic production, particularly concerning carbon accounting, would help level the playing field for both international and domestic producers.

Policymakers should carefully consider regulatory mechanisms to ensure fair competition and avoid inadvertently creating advantages for one set of producers. If the EU wishes to prevent carbon leakage in the absence of full shipping emissions accounting, targeted financial support for European ammonia producers or refinements to emissions accounting methodologies may be necessary to ensure equitable treatment for domestic production.

In the longer term, the EU will likely seek to address any remaining regulatory gaps, aiming for a more holistic emissions accounting framework that encompasses all components of the supply chain. However, the current partial coverage could have adverse effects on investment decisions, cost structures, and Europe's broader decarbonization efforts if left unaddressed. This potential for incomplete coverage may distort competition in favor of imports. Consequently, it remains paramount for policymakers to tackle such potential issues and establish balanced, comprehensive carbon accounting across both domestic and imported ammonia in tomorrow's ammonia supply chains.

6.7 Encouraging Infrastructure Investment to Support a More Diverse Low-Carbon Ammonia Market

While policy discussions have primarily focused on carbon pricing and subsidies, infrastructure investment is another crucial enabler for ammonia decarbonisation. The lack of large-scale hydrogen transportation infrastructure limits the ability of some regions to leverage their renewable energy potential.

Investing in pipeline infrastructure, storage solutions, and port facilities for ammonia and hydrogen transport could help integrate low-cost production regions with high-demand industrial centres. A

coordinated Pan-European hydrogen and ammonia infrastructure strategy would enhance flexibility, allowing for a more diversified ammonia supply mix that is not overly dependent on any single production pathway.

Additionally, importing low-carbon hydrogen based on biomass from the US is better than importing raw biomass for hydrogen production in Europe. The latter faces substantial supply chain emissions penalties under EU regulations, whereas current EU regulations allow for bypassing a portion of the emissions during the transportation phase. This policy asymmetry makes direct hydrogen imports from the US (and potentially other regions) a strategically favourable option.

7. Conclusion

This study provides a comprehensive economic, policy and energy market modelling assessment of the pathways available for decarbonising ammonia production in Europe, considering economic feasibility, policy constraints, and the implications of regulatory frameworks such as CI thresholds, CBAM, and RED III. By modelling multiple hydrogen production pathways – including SMR, CCS, $BIOH_2$, and electrolysis-based renewable hydrogen – across 52 ammonia production sites in Europe, this research identifies key economic and policy barriers that must be addressed to enable a cost-effective transition towards renewable and low-carbon ammonia. The findings underscore the significant role of policy interventions, such as subsidies and carbon pricing, in shaping the financial viability of alternative hydrogen pathways. Additionally, the study highlights the challenges posed by strict time-matching requirements for renewable electricity in hydrogen production. It explores the competitiveness of transatlantic ammonia trade under CI thresholds, CBAM, and RED III constraints.

From an economic perspective, our analysis reveals that without subsidies or carbon pricing, depreciated SMR-based ammonia production remains the most financially competitive option due to its low operational costs and lack of reinvestment requirements. In contrast, low-carbon alternatives – including renewable ammonia, CCS-based ammonia, and $BIOH_2$ – exhibit significantly lower NPVs, primarily due to the capital-intensive nature of new infrastructure investments and the requirement for extensive renewable generation and energy storage in islanded setups. Even in regions with abundant renewable resources, the high CAPEX required for oversized wind, solar, and battery storage facilities keeps the NPV of green ammonia negative, limiting its financial attractiveness under market conditions without policy support.

However, a notable shift in economic performance occurs in the policy support scenario, where carbon pricing is introduced for SMR, CCS, and $BIOH_2$, while renewable ammonia benefits from subsidies. Carbon prices significantly reduce the NPV of fossil-based ammonia pathways, especially impacting $BIOH_2$, which is subject to pricing on upstream emissions but remains ineligible for subsidies under the current support mechanism criteria. The results also demonstrate that renewable ammonia benefits from direct financial support, improving its economic feasibility, particularly in existing SMR locations with high renewable energy availability, such as Spain, Portugal, Bulgaria, and Nordic countries. However, in some existing sites with low renewable potential and high opex, such as those in Germany and Austria, the financial viability of renewable ammonia remains challenging due to high input costs, the need for large-scale storage, and expensive renewable overcapacity requirements. Despite these policy-driven shifts, most hydrogen-based ammonia pathways still struggle to achieve positive NPVs in 2030 and 2040. This finding reinforces the need for more substantial financial incentives, environmental regulatory flexibility, or infrastructure investment to enable a viable transition.

The study also examines the impact of time-matching requirements for renewable electricity in ammonia production. Our findings indicate that enforcing strict hourly matching, as mandated by RED III, significantly increases production costs due to the need for excessive overinvestment in battery storage and renewable overcapacity. This cost penalty varies across regions, with some existing sites having stable and complementary wind and solar resources (e.g., those in Bulgaria, Greece, and the UK) experiencing a lower financial impact. At the same time, those existing SMR sites with low potential and higher renewable intermittency (e.g., Slovakia, Romania, and Croatia) suffer from extreme reductions in NPV. The study proposes a monthly-hourly hybrid matching approach, where ammonia plants size their renewable energy capacity based on monthly matching and supplement the remainder through

the grid in alignment with the national electricity grid decarbonisation trends rather than a rigid 90% clean electricity requirement. This adjustment serves as a no-cost policy instrument that would significantly improve the economics of constructing a renewable ammonia plant by reducing the need for excessive overcapacity and storage while ensuring alignment with broader energy transition goals. Moreover, this approach is inherently temporary, as most national grids are expected to exceed 90% clean electricity by 2040 under the projections of the Fit for 55 package and the European Green Deal, making strict hourly matching more viable in the long term.

The final component of this research explores the potential for transatlantic ammonia under CI thresholds, CBAM, and RED III constraints. Our analysis confirms that US-produced ammonia from CCS, $BIOH_2$, and renewable hydrogen can meet European CI thresholds, making it eligible for import into the EU. Furthermore, economic modelling reveals that by 2030, US ammonia produced from $BIOH_2$ and CCS is competitive with European counterparts and, in some cases, even more economically attractive than depreciated SMR-based ammonia in Europe. By 2040, US renewable ammonia also becomes cost-competitive due to declining electrolyser costs and improved efficiencies. Additionally, under current regaulation, imported hydrogen has the potential to bypass 50% of the emissions associated with transatlantic transportation. This potential advantage for imports makes directly importing low-carbon hydrogen from the US a strategically advantageous route, avoiding additional supply chain emissions penalties while ensuring a more efficient decarbonisation pathway for EU hydrogen consumption. This suggests that US clean ammonia could capture a significant share of the European market in the coming decades. However, it also raises concerns about the long-term competitiveness of European ammonia production, particularly for those relying on subsidised renewable production, as they may struggle to compete against lower-cost imports.

If European producers fail to match the competitiveness of US imports when both operate under the same regulatory conditions, this could be attributed to better efficiency or other market-driven variables—aligning with the principles of healthy competition. However, if the advantage arises from an uneven playing field, such as differences in carbon accounting, it becomes difficult to classify the market as competitive. Future policy adjustments must balance industrial resilience and competitiveness with market openness to cleaner, lower-cost imports.

In conclusion, this study highlights the significant financial and regulatory challenges that must be addressed to decarbonise ammonia production in Europe. While policy mechanisms such as carbon pricing and subsidies can improve the financial viability of renewable ammonia, their effectiveness varies widely across different regions, and a one-size-fits-all approach is unlikely to succeed. Instead, a more regionally flexible policy framework that includes monthly-hourly hybrid matching targeted financial incentives, and cross-border infrastructure investment – such as Pan-European hydrogen pipeline and storage development – will ensure a cost-effective and resilient ammonia supply chain. Additionally, as transatlantic trade in low-carbon ammonia grows under EU CI thresholds, CBAM, and RED III, European policymakers must carefully balance promoting domestic ammonia production and leveraging cost-competitive imports from the US and other global markets.

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Appendices

A1. Location of Considered Plants

Table 16: Location of the considered plants

Country	Location	Latitude	Longitude
Austria	A	48.24106	14.29315
Belgium	B	50.49587	3.86435
Belgium	C	51.14084	4.35573
Belgium	D	50.65450	5.46578
Bulgaria	E	42.26546	25.84214
Bulgaria	F	43.17404	27.72172
Croatia	G	45.48962	16.75852
Czechia	H	50.68750	14.03628
Finland	I	63.06337	27.90561
Finland	J	61.11356	21.73103
France	K	47.78719	7.50651
France	L	49.49437	0.10793
France	M	48.58544	2.97812
France	N	49.41181	1.04138
France	O	43.62564	-0.93818
France	P	44.96721	-0.79100
France	Q	47.36643	-2.48030
Germany	R	48.10887	12.45931
Germany	S	49.76899	8.59661
Germany	T	51.64422	7.13102
Germany	U	51.34441	7.66794
Germany	V	51.50995	9.76019
Germany	W	51.82174	12.48070
Germany	X	54.08521	12.12505
Germany	Y	53.99700	9.19697
Greece	Z	40.95115	24.42984
Hungary	AA	47.27034	18.18569
Italy	BB	44.83912	11.61979
Italy	CC	44.34002	12.14991
Lithuania	DD	55.17410	24.32187
Netherlands	EE	51.27770	3.83669
Netherlands	FF	50.96821	5.82772
Netherlands	GG	52.49387	5.07030
Norway	HH	59.13856	9.65551
Norway	II	66.95229	14.54246
Poland	JJ	52.64933	19.06774
Poland	KK	51.41644	21.96931

Poland	LL	53.56268	14.53864
Poland	MM	50.33830	18.18133
Poland	NN	50.33730	18.18133
Poland	OO	50.21179	20.95083
Poland	PP	54.46108	18.57237
Portugal	QQ	38.71958	-9.02703
Romania	RR	46.64285	24.81617
Slovakia	SS	48.31370	17.83153
Spain	TT	42.51936	-0.36381
Spain	UU	38.68945	-4.10789
Spain	VV	37.26196	-6.94273
Spain	WW	39.77534	-0.16856
Spain	XX	43.45095	-6.28228
UK	YY	53.42037	-2.96299
UK	ZZ	54.64212	-1.24964

Source: Adapted from [92]

A2. Detailed Country NPV IQR Range

Table 17: 2030 interquartile NPV range (25th percentile - median - 75th percentile) for the various countries, cases, and pathways

Country	Pathway	Case	NPV IQR_25	NPV IQR_50	NPV IQR_75
Austria	$BIOH_2$	PSS	-131	-101	-64
Austria	$BIOH_2$	RCS	-55	-27	4
Austria	CCS	PSS	-126	-107	-83
Austria	CCS	RCS	-103	-85	-62
Austria	Renewables	PSS	-115	-75	-29
Austria	Renewables	RCS	-125	-85	-39
Austria	SMR	PSS	-73	-52	-28
Austria	SMR	RCS	-10	5	23
Belgium	$BIOH_2$	PSS	-136	-107	-71
Belgium	$BIOH_2$	RCS	-60	-33	-2
Belgium	CCS	PSS	-125	-107	-84
Belgium	CCS	RCS	-103	-85	-63
Belgium	Renewables	PSS	-68	-35	6
Belgium	Renewables	RCS	-79	-45	-5
Belgium	SMR	PSS	-78	-58	-35
Belgium	SMR	RCS	-15	0	17
Bulgaria	$BIOH_2$	PSS	-108	-79	-44
Bulgaria	$BIOH_2$	RCS	-33	-8	20
Bulgaria	CCS	PSS	-100	-82	-59
Bulgaria	CCS	RCS	-78	-60	-39
Bulgaria	Renewables	PSS	-20	12	46
Bulgaria	Renewables	RCS	-30	1	36
Bulgaria	SMR	PSS	-59	-39	-17
Bulgaria	SMR	RCS	2	15	32
Croatia	$BIOH_2$	PSS	-138	-108	-71
Croatia	$BIOH_2$	RCS	-61	-34	-2
Croatia	CCS	PSS	-129	-110	-87
Croatia	CCS	RCS	-107	-89	-67
Croatia	Renewables	PSS	-148	-114	-73
Croatia	Renewables	RCS	-158	-124	-84
Croatia	SMR	PSS	-71	-52	-29
Croatia	SMR	RCS	-9	6	23
Czech Republic	$BIOH_2$	PSS	-117	-86	-49
Czech Republic	$BIOH_2$	RCS	-41	-15	16
Czech Republic	CCS	PSS	-112	-93	-70
Czech Republic	CCS	RCS	-90	-72	-49
Czech Republic	Renewables	PSS	-77	-39	4
Czech Republic	Renewables	RCS	-87	-49	-6

Czech Republic	SMR	PSS	-64	-44	-20
Czech Republic	SMR	RCS	-2	12	29
Finland	$BIOH_2$	PSS	-141	-113	-77
Finland	$BIOH_2$	RCS	-65	-38	-7
Finland	CCS	PSS	-127	-109	-86
Finland	CCS	RCS	-105	-87	-66
Finland	Renewables	PSS	-104	-67	-26
Finland	Renewables	RCS	-114	-77	-36
Finland	SMR	PSS	-76	-57	-35
Finland	SMR	RCS	-13	1	18
France	$BIOH_2$	PSS	-245	-133	-91
France	$BIOH_2$	RCS	-168	-57	-19
France	CCS	PSS	-282	-124	-97
France	CCS	RCS	-261	-102	-76
France	Renewables	PSS	-1447	-96	-43
France	Renewables	RCS	-1457	-106	-53
France	SMR	PSS	-77	-57	-34
France	SMR	RCS	-14	1	18
Germany	$BIOH_2$	PSS	-136	-106	-70
Germany	$BIOH_2$	RCS	-60	-32	-2
Germany	CCS	PSS	-126	-107	-84
Germany	CCS	RCS	-104	-86	-63
Germany	Renewables	PSS	-102	-67	-25
Germany	Renewables	RCS	-112	-77	-35
Germany	SMR	PSS	-74	-55	-32
Germany	SMR	RCS	-12	3	20
Greece	$BIOH_2$	PSS	-121	-92	-56
Greece	$BIOH_2$	RCS	-45	-19	11
Greece	CCS	PSS	-112	-93	-70
Greece	CCS	RCS	-90	-72	-50
Greece	Renewables	PSS	-42	-8	31
Greece	Renewables	RCS	-52	-18	21
Greece	SMR	PSS	-68	-49	-26
Greece	SMR	RCS	-6	8	25
Hungary	$BIOH_2$	PSS	-122	-92	-54
Hungary	$BIOH_2$	RCS	-46	-19	12
Hungary	CCS	PSS	-118	-99	-76
Hungary	CCS	RCS	-96	-78	-55
Hungary	Renewables	PSS	-120	-88	-48
Hungary	Renewables	RCS	-130	-98	-59
Hungary	SMR	PSS	-64	-43	-20

Hungary	SMR	RCS	-2	12	30
Italy	$BIOH_2$	PSS	-129	-98	-61
Italy	$BIOH_2$	RCS	-53	-24	7
Italy	CCS	PSS	-126	-106	-82
Italy	CCS	RCS	-103	-84	-61
Italy	Renewables	PSS	-133	-85	-36
Italy	Renewables	RCS	-143	-95	-46
Italy	SMR	PSS	-70	-49	-26
Italy	SMR	RCS	-8	7	25
Lithuania	$BIOH_2$	PSS	-126	-97	-62
Lithuania	$BIOH_2$	RCS	-50	-24	6
Lithuania	CCS	PSS	-116	-98	-76
Lithuania	CCS	RCS	-94	-77	-55
Lithuania	Renewables	PSS	-133	-99	-57
Lithuania	Renewables	RCS	-144	-109	-67
Lithuania	SMR	PSS	-62	-42	-20
Lithuania	SMR	RCS	0	13	29
Netherlands	$BIOH_2$	PSS	-132	-103	-66
Netherlands	$BIOH_2$	RCS	-56	-29	2
Netherlands	CCS	PSS	-121	-103	-80
Netherlands	CCS	RCS	-99	-82	-59
Netherlands	Renewables	PSS	-60	-26	16
Netherlands	Renewables	RCS	-70	-36	6
Netherlands	SMR	PSS	-76	-56	-33
Netherlands	SMR	RCS	-13	2	19
Norway	$BIOH_2$	PSS	-149	-121	-85
Norway	$BIOH_2$	RCS	-73	-45	-13
Norway	CCS	PSS	-135	-116	-94
Norway	CCS	RCS	-112	-95	-73
Norway	Renewables	PSS	-143	-103	-61
Norway	Renewables	RCS	-153	-114	-71
Norway	SMR	PSS	-79	-59	-37
Norway	SMR	RCS	-16	-1	16
Poland	$BIOH_2$	PSS	-119	-90	-54
Poland	$BIOH_2$	RCS	-43	-17	12
Poland	CCS	PSS	-111	-92	-69
Poland	CCS	RCS	-88	-71	-48
Poland	Renewables	PSS	-81	-40	4
Poland	Renewables	RCS	-92	-50	-6
Poland	SMR	PSS	-62	-43	-20
Poland	SMR	RCS	-1	13	29

Portugal	$BIOH_2$	PSS	-116	-86	-49
Portugal	$BIOH_2$	RCS	-40	-14	16
Portugal	CCS	PSS	-109	-91	-67
Portugal	CCS	RCS	-87	-69	-47
Portugal	Renewables	PSS	-56	-21	19
Portugal	Renewables	RCS	-66	-31	9
Portugal	SMR	PSS	-64	-44	-21
Portugal	SMR	RCS	-2	12	29
Romania	$BIOH_2$	PSS	-209	-179	-142
Romania	$BIOH_2$	RCS	-132	-103	-66
Romania	CCS	PSS	-209	-191	-168
Romania	CCS	RCS	-187	-169	-147
Romania	Renewables	PSS	-834	-797	-754
Romania	Renewables	RCS	-844	-807	-765
Romania	SMR	PSS	-61	-41	-19
Romania	SMR	RCS	0	14	30
Slovakia	$BIOH_2$	PSS	-172	-141	-103
Slovakia	$BIOH_2$	RCS	-95	-65	-30
Slovakia	CCS	PSS	-173	-153	-130
Slovakia	CCS	RCS	-150	-132	-109
Slovakia	Renewables	PSS	-538	-504	-463
Slovakia	Renewables	RCS	-548	-514	-473
Slovakia	SMR	PSS	-63	-42	-19
Slovakia	SMR	RCS	-1	13	30
Spain	$BIOH_2$	PSS	-134	-101	-63
Spain	$BIOH_2$	RCS	-58	-27	5
Spain	CCS	PSS	-132	-105	-79
Spain	CCS	RCS	-110	-84	-59
Spain	Renewables	PSS	-233	-66	-1
Spain	Renewables	RCS	-243	-76	-11
Spain	SMR	PSS	-66	-46	-23
Spain	SMR	RCS	-4	10	27
United Kingdom	$BIOH_2$	PSS	-127	-98	-62
United Kingdom	$BIOH_2$	RCS	-51	-24	5
United Kingdom	CCS	PSS	-118	-99	-76
United Kingdom	CCS	RCS	-95	-78	-55
United Kingdom	Renewables	PSS	-54	-19	20
United Kingdom	Renewables	RCS	-64	-29	10
United Kingdom	SMR	PSS	-73	-53	-30
United Kingdom	SMR	RCS	-10	5	22

Source: Authors' contributions

Table 18: 2040 interquartile NPV range (25th percentile - median - 75th percentile) for the various countries, cases, and pathways

Country	Technology	Case	NPV IQR_25	NPV IQR_50	NPV IQR_75
Austria	$BIOH_2$	PSS	-150	-114	-60
Austria	$BIOH_2$	RCS	-73	-39	7
Austria	CCS	PSS	-116	-93	-64
Austria	CCS	RCS	-94	-72	-43
Austria	Renewables	PSS	-85	-44	11
Austria	Renewables	RCS	-95	-54	0
Austria	SMR	PSS	-84	-60	-29
Austria	SMR	RCS	-20	-1	22
Belgium	$BIOH_2$	PSS	-156	-122	-69
Belgium	$BIOH_2$	RCS	-79	-46	0
Belgium	CCS	PSS	-117	-96	-67
Belgium	CCS	RCS	-95	-74	-46
Belgium	Renewables	PSS	-58	-20	32
Belgium	Renewables	RCS	-68	-30	22
Belgium	SMR	PSS	-89	-66	-36
Belgium	SMR	RCS	-26	-6	17
Bulgaria	$BIOH_2$	PSS	-129	-95	-43
Bulgaria	$BIOH_2$	RCS	-53	-21	22
Bulgaria	CCS	PSS	-94	-72	-43
Bulgaria	CCS	RCS	-71	-51	-23
Bulgaria	Renewables	PSS	-19	17	65
Bulgaria	Renewables	RCS	-29	7	55
Bulgaria	SMR	PSS	-70	-47	-18
Bulgaria	SMR	RCS	-7	10	31
Croatia	$BIOH_2$	PSS	-153	-119	-66
Croatia	$BIOH_2$	RCS	-77	-43	2
Croatia	CCS	PSS	-117	-95	-66
Croatia	CCS	RCS	-95	-74	-46
Croatia	Renewables	PSS	-103	-65	-13
Croatia	Renewables	RCS	-113	-76	-23
Croatia	SMR	PSS	-82	-59	-30
Croatia	SMR	RCS	-19	0	22
Czech Republic	$BIOH_2$	PSS	-137	-102	-48
Czech Republic	$BIOH_2$	RCS	-61	-27	18
Czech Republic	CCS	PSS	-104	-82	-52
Czech Republic	CCS	RCS	-83	-61	-32
Czech Republic	Renewables	PSS	-62	-21	34
Czech Republic	Renewables	RCS	-72	-31	23
Czech Republic	SMR	PSS	-75	-51	-21

Czech Republic	SMR	RCS	-12	6	29
Finland	$BIOH_2$	PSS	-159	-126	-75
Finland	$BIOH_2$	RCS	-82	-50	-4
Finland	CCS	PSS	-117	-96	-69
Finland	CCS	RCS	-96	-75	-48
Finland	Renewables	PSS	-80	-40	11
Finland	Renewables	RCS	-90	-50	1
Finland	SMR	PSS	-87	-64	-36
Finland	SMR	RCS	-23	-5	17
France	$BIOH_2$	PSS	-181	-140	-85
France	$BIOH_2$	RCS	-104	-64	-14
France	CCS	PSS	-159	-110	-79
France	CCS	RCS	-138	-88	-58
France	Renewables	PSS	-592	-65	-8
France	Renewables	RCS	-603	-76	-18
France	SMR	PSS	-87	-64	-35
France	SMR	RCS	-24	-5	18
Germany	$BIOH_2$	PSS	-155	-120	-68
Germany	$BIOH_2$	RCS	-78	-44	1
Germany	CCS	PSS	-117	-95	-66
Germany	CCS	RCS	-95	-74	-45
Germany	Renewables	PSS	-80	-41	11
Germany	Renewables	RCS	-90	-52	1
Germany	SMR	PSS	-85	-62	-33
Germany	SMR	RCS	-22	-3	19
Greece	$BIOH_2$	PSS	-143	-109	-57
Greece	$BIOH_2$	RCS	-66	-33	11
Greece	CCS	PSS	-106	-84	-56
Greece	CCS	RCS	-84	-63	-35
Greece	Renewables	PSS	-47	-8	42
Greece	Renewables	RCS	-57	-18	32
Greece	SMR	PSS	-79	-56	-27
Greece	SMR	RCS	-16	2	24
Hungary	$BIOH_2$	PSS	-139	-103	-49
Hungary	$BIOH_2$	RCS	-62	-28	16
Hungary	CCS	PSS	-106	-84	-54
Hungary	CCS	RCS	-84	-62	-33
Hungary	Renewables	PSS	-75	-37	17
Hungary	Renewables	RCS	-85	-48	7
Hungary	SMR	PSS	-75	-51	-21
Hungary	SMR	RCS	-12	7	29

Italy	$BIOH_2$	PSS	-148	-112	-57
Italy	$BIOH_2$	RCS	-71	-37	10
Italy	CCS	PSS	-116	-93	-63
Italy	CCS	RCS	-94	-72	-42
Italy	Renewables	PSS	-99	-56	1
Italy	Renewables	RCS	-109	-66	-9
Italy	SMR	PSS	-81	-57	-26
Italy	SMR	RCS	-18	1	24
Lithuania	$BIOH_2$	PSS	-141	-107	-56
Lithuania	$BIOH_2$	RCS	-64	-32	11
Lithuania	CCS	PSS	-104	-83	-55
Lithuania	CCS	RCS	-82	-62	-34
Lithuania	Renewables	PSS	-86	-49	3
Lithuania	Renewables	RCS	-97	-59	-7
Lithuania	SMR	PSS	-72	-49	-21
Lithuania	SMR	RCS	-9	8	29
Netherlands	$BIOH_2$	PSS	-152	-118	-66
Netherlands	$BIOH_2$	RCS	-76	-42	3
Netherlands	CCS	PSS	-114	-92	-64
Netherlands	CCS	RCS	-92	-71	-43
Netherlands	Renewables	PSS	-51	-13	38
Netherlands	Renewables	RCS	-61	-23	28
Netherlands	SMR	PSS	-86	-63	-34
Netherlands	SMR	RCS	-23	-4	18
Norway	$BIOH_2$	PSS	-165	-132	-81
Norway	$BIOH_2$	RCS	-88	-55	-10
Norway	CCS	PSS	-123	-103	-75
Norway	CCS	RCS	-102	-81	-54
Norway	Renewables	PSS	-106	-66	-14
Norway	Renewables	RCS	-117	-76	-24
Norway	SMR	PSS	-89	-67	-38
Norway	SMR	RCS	-26	-7	15
Poland	$BIOH_2$	PSS	-138	-104	-53
Poland	$BIOH_2$	RCS	-61	-29	13
Poland	CCS	PSS	-102	-80	-52
Poland	CCS	RCS	-80	-59	-31
Poland	Renewables	PSS	-62	-21	33
Poland	Renewables	RCS	-72	-31	23
Poland	SMR	PSS	-73	-50	-21
Poland	SMR	RCS	-10	7	29
Portugal	$BIOH_2$	PSS	-136	-102	-49

Portugal	$BIOH_2$	RCS	-60	-27	17
Portugal	CCS	PSS	-102	-80	-51
Portugal	CCS	RCS	-80	-59	-30
Portugal	Renewables	PSS	-48	-10	42
Portugal	Renewables	RCS	-58	-20	31
Portugal	SMR	PSS	-75	-51	-21
Portugal	SMR	RCS	-12	6	28
Romania	$BIOH_2$	PSS	-180	-145	-92
Romania	$BIOH_2$	RCS	-103	-69	-19
Romania	CCS	PSS	-148	-126	-97
Romania	CCS	RCS	-126	-105	-77
Romania	Renewables	PSS	-417	-380	-326
Romania	Renewables	RCS	-428	-390	-336
Romania	SMR	PSS	-72	-49	-19
Romania	SMR	RCS	-9	8	30
Slovakia	$BIOH_2$	PSS	-165	-128	-74
Slovakia	$BIOH_2$	RCS	-88	-52	-4
Slovakia	CCS	PSS	-134	-112	-82
Slovakia	CCS	RCS	-112	-90	-61
Slovakia	Renewables	PSS	-293	-256	-202
Slovakia	Renewables	RCS	-304	-266	-212
Slovakia	SMR	PSS	-74	-50	-20
Slovakia	SMR	RCS	-11	7	29
Spain	$BIOH_2$	PSS	-147	-111	-58
Spain	$BIOH_2$	RCS	-71	-36	9
Spain	CCS	PSS	-115	-90	-60
Spain	CCS	RCS	-93	-69	-40
Spain	Renewables	PSS	-136	-44	19
Spain	Renewables	RCS	-147	-54	9
Spain	SMR	PSS	-77	-54	-24
Spain	SMR	RCS	-14	4	26
United Kingdom	$BIOH_2$	PSS	-148	-114	-61
United Kingdom	$BIOH_2$	RCS	-72	-38	7
United Kingdom	CCS	PSS	-111	-89	-60
United Kingdom	CCS	RCS	-89	-68	-40
United Kingdom	Renewables	PSS	-49	-10	41
United Kingdom	Renewables	RCS	-59	-20	31
United Kingdom	SMR	PSS	-84	-60	-31
United Kingdom	SMR	RCS	-20	-1	21

Source: Authors' contributions

A3. Renewables Availability

Table 19: The hourly availability factor over the year for wind and solar across the different considered locations

Location	Country	Wind Availability Factor (%)		Solar Availability Factor (%)	
		2030	2040	2030	2040
A	Austria	25.8%	25.8%	15.6%	15.6%
B	Belgium	31.4%	31.4%	14.4%	14.4%
C	Belgium	31.2%	31.2%	14.2%	14.2%
D	Belgium	30.5%	30.5%	14.3%	14.3%
E	Bulgaria	22.1%	22.1%	17.8%	17.8%
F	Bulgaria	33.1%	33.1%	17.8%	17.8%
G	Croatia	24.0%	24.0%	16.0%	16.0%
H	Czechia	26.7%	26.7%	15.1%	15.1%
I	Finland	30.1%	30.1%	10.9%	10.9%
J	Finland	34.6%	34.6%	12.0%	12.0%
K	France	18.4%	18.4%	15.8%	15.8%
L	France	46.5%	46.5%	15.0%	15.0%
M	France	29.4%	29.4%	15.1%	15.1%
N	France	33.8%	33.8%	14.9%	14.9%
O	France	21.3%	21.3%	16.6%	16.6%
P	France	27.5%	27.5%	16.5%	16.5%
Q	France	45.9%	45.9%	15.9%	15.9%
R	Germany	18.1%	18.1%	15.2%	15.2%
S	Germany	20.2%	20.2%	14.8%	14.8%
T	Germany	26.6%	26.6%	14.0%	14.0%
U	Germany	26.4%	26.4%	14.2%	14.2%
V	Germany	23.9%	23.9%	14.3%	14.3%
W	Germany	24.8%	24.8%	14.4%	14.4%
X	Germany	35.0%	35.0%	13.3%	13.3%
Y	Germany	33.0%	33.0%	13.2%	13.2%
Z	Greece	18.7%	18.7%	17.8%	17.8%
AA	Hungary	34.9%	34.9%	15.8%	15.8%
BB	Italy	19.1%	19.1%	16.4%	16.4%
CC	Italy	22.1%	22.1%	16.8%	16.8%
DD	Lithuania	23.3%	23.3%	12.7%	12.7%
EE	Netherlands	33.8%	33.8%	14.2%	14.2%
FF	Netherlands	28.1%	28.1%	14.4%	14.4%
GG	Netherlands	35.0%	35.0%	14.1%	14.1%
HH	Norway	24.5%	24.5%	12.1%	12.1%
II	Norway	26.9%	26.9%	10.0%	10.0%
JJ	Poland	26.4%	26.4%	14.2%	14.2%
KK	Poland	25.1%	25.1%	14.4%	14.4%
LL	Poland	30.0%	30.0%	13.2%	13.2%

MM	Poland	25.2%	25.2%	15.0%	15.0%
NN	Poland	25.2%	25.2%	15.0%	15.0%
OO	Poland	23.6%	23.6%	14.9%	14.9%
PP	Poland	47.8%	47.8%	13.5%	13.5%
QQ	Portugal	44.6%	44.6%	19.7%	19.7%
RR	Romania	21.9%	21.9%	16.8%	16.8%
SS	Slovakia	37.0%	37.0%	15.6%	15.6%
TT	Spain	25.8%	25.8%	19.3%	19.3%
UU	Spain	29.4%	29.4%	20.1%	20.1%
VV	Spain	33.6%	33.6%	20.6%	20.6%
WW	Spain	28.2%	28.2%	20.1%	20.1%
XX	Spain	33.2%	33.2%	17.2%	17.2%
YY	UK	35.6%	35.6%	13.0%	13.0%
ZZ	UK	39.7%	39.7%	13.0%	13.0%

Source: Computed from [105]

A4. Projected Labour Costs

Table 20: Projected hourly labour costs for the considered countries in 2030 and 2040

Country	Projected Labour Cost ($/hour)		Notes
	2030	2040	
Austria	46.3	52.4	
Belgium	64.7	75.4	
Bulgaria	4.0	4.8	
Croatia	43.3	53.7	Handled Croatia using an average of neighbours: Hungary, Slovakia, Austria
Czechia	19.0	23.8	
Finland	59.1	70.3	
France	59.4	69.6	
Germany	52.9	60.3	
Greece	33.7	40.6	
Hungary	17.5	21.8	
Italy	38.5	44.4	
Lithuania	11.3	14.2	
Netherlands	56.9	66.7	
Norway	66.3	78.6	Handled Norway using an average of neighbours: Denmark, Sweden
Poland	14.0	17.0	
Portugal	18.5	22.0	
Romania	9.6	12.4	
Slovakia	14.7	18.4	
Spain	26.4	29.3	
UK	47.6	55.6	

Source: Projected based on data from [89]

A5. Ranked NPVs for the Considered Locations

Table 21: Location ranking based on NPV from highest to lowest in 2030

Rank	Latitude	Longitude	RCS NPV	PSS NPV	Country	Location
1	43.17404	27.72172	11	22	Bulgaria	F
2	37.26196	-6.94273	4	14	Spain	VV
3	54.46108	18.57237	1	11	Poland	PP
4	42.26546	25.84214	-11	-1	Bulgaria	E
5	54.64212	-1.24964	-16	-5	UK	ZZ
6	51.2777	3.836688	-18	-8	Netherlands	EE
7	40.95115	24.42984	-18	-8	Greece	Z
8	43.45095	-6.28228	-31	-21	Spain	XX
9	38.71958	-9.02703	-31	-21	Portugal	QQ
10	52.49387	5.070296	-34	-23	Netherlands	GG
11	51.14084	4.355729	-37	-27	Belgium	C
12	52.64933	19.06774	-43	-33	Poland	JJ
13	53.42037	-2.96299	-43	-33	UK	YY
14	50.49587	3.864348	-44	-34	Belgium	B
15	50.3383	18.18133	-44	-34	Poland	MM
16	49.49437	0.107929	-44	-34	France	L
17	50.3373	18.18133	-48	-38	Poland	NN
18	44.96721	-0.791	-49	-38	France	P
19	50.6875	14.03628	-49	-39	Czechia	H
20	51.41644	21.96931	-54	-44	Poland	KK
21	50.96821	5.827725	-55	-45	Netherlands	FF
22	50.6545	5.465783	-56	-46	Belgium	D
23	42.51936	-0.36381	-58	-48	Spain	TT
24	44.34002	12.14991	-60	-50	Italy	CC
25	51.64422	7.131018	-66	-56	Germany	T
26	54.08521	12.12505	-67	-57	Germany	X
27	53.997	9.196966	-73	-63	Germany	Y
28	63.06337	27.90561	-73	-63	Finland	I
29	48.10887	12.45931	-74	-63	Germany	R
30	51.50995	9.760189	-75	-65	Germany	V
31	49.41181	1.041384	-76	-66	France	N
32	51.34441	7.667936	-77	-67	Germany	U
33	61.11356	21.73103	-81	-70	Finland	J
34	48.24106	14.29315	-85	-75	Austria	A
35	47.36643	-2.4803	-86	-76	France	Q
36	51.82174	12.4807	-87	-77	Germany	W
37	50.21179	20.95083	-90	-80	Poland	OO
38	59.13856	9.655515	-95	-85	Norway	HH
39	47.27034	18.18569	-98	-88	Hungary	AA
40	53.56268	14.53864	-101	-91	Poland	LL

41	49.76899	8.596606	-107	-97	Germany	S
42	55.1741	24.32187	-109	-99	Lithuania	DD
43	45.48962	16.75852	-124	-114	Croatia	G
44	44.83912	11.61979	-137	-127	Italy	BB
45	48.58544	2.978117	-138	-128	France	M
46	66.95229	14.54246	-140	-130	Norway	II
47	39.77534	-0.16856	-215	-204	Spain	WW
48	38.68945	-4.10789	-459	-449	Spain	UU
49	48.3137	17.83153	-514	-504	Slovakia	SS
50	46.64285	24.81617	-807	-797	Romania	RR
51	43.62564	-0.93818	-1505	-1495	France	O
52	47.78719	7.506512	-2189	-2179	France	K

Source: Authors' contributions

Table 22: Location ranking based on NPV from highest to lowest in 2040

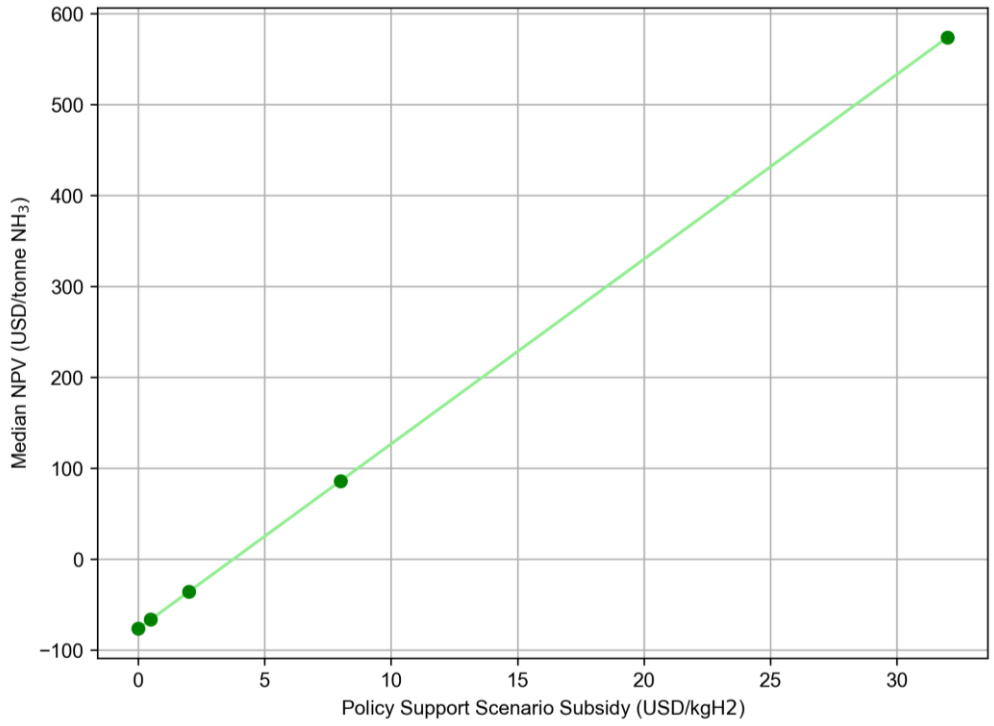
Rank	latitude	longitude	RCS NPV	PSS NPV	Country	Location
1	43.17404	27.72172	16	26	Bulgaria	F
2	54.46108	18.57237	6	16	Poland	PP
3	37.26196	-6.94273	4	14	Spain	VV
4	42.26546	25.84214	-3	7	Bulgaria	E
5	51.2777	3.836688	-9	2	Netherlands	EE
6	54.64212	-1.24964	-12	-2	UK	ZZ
7	43.45095	-6.28228	-16	-6	Spain	XX
8	40.95115	24.42984	-18	-8	Greece	Z
9	38.71958	-9.02703	-20	-10	Portugal	QQ
10	52.64933	19.06774	-21	-11	Poland	JJ
11	51.14084	4.355729	-23	-12	Belgium	C
12	44.96721	-0.791	-25	-14	France	P
13	50.3383	18.18133	-25	-15	Poland	MM
14	49.49437	0.107929	-26	-16	France	L
15	50.49587	3.864348	-27	-17	Belgium	B
16	50.3373	18.18133	-28	-18	Poland	NN
17	51.41644	21.96931	-28	-18	Poland	KK
18	53.42037	-2.96299	-30	-20	UK	YY
19	52.49387	5.070296	-30	-20	Netherlands	GG
20	50.6875	14.03628	-31	-21	Czechia	H
21	50.96821	5.827725	-32	-22	Netherlands	FF
22	42.51936	-0.36381	-37	-27	Spain	TT
23	51.64422	7.131018	-40	-30	Germany	T
24	50.6545	5.465783	-41	-31	Belgium	D
25	63.06337	27.90561	-43	-33	Finland	I
26	54.08521	12.12505	-44	-34	Germany	X
27	53.997	9.196966	-45	-34	Germany	Y

28	44.34002	12.14991	-46	-36	Italy	CC
29	47.27034	18.18569	-48	-37	Hungary	AA
30	49.41181	1.041384	-48	-38	France	N
31	51.34441	7.667936	-49	-38	Germany	U
32	51.50995	9.760189	-50	-40	Germany	V
33	47.36643	-2.4803	-52	-42	France	Q
34	48.24106	14.29315	-54	-44	Austria	A
35	59.13856	9.655515	-54	-44	Norway	HH
36	61.11356	21.73103	-57	-47	Finland	J
37	50.21179	20.95083	-58	-48	Poland	OO
38	48.10887	12.45931	-59	-48	Germany	R
39	55.1741	24.32187	-59	-49	Lithuania	DD
40	49.76899	8.596606	-65	-55	Germany	S
41	51.82174	12.4807	-69	-58	Germany	W
42	45.48962	16.75852	-76	-65	Croatia	G
43	48.58544	2.978117	-76	-66	France	M
44	53.56268	14.53864	-84	-74	Poland	LL
45	44.83912	11.61979	-90	-80	Italy	BB
46	66.95229	14.54246	-105	-95	Norway	II
47	39.77534	-0.16856	-131	-120	Spain	WW
48	38.68945	-4.10789	-245	-235	Spain	UU
49	48.3137	17.83153	-266	-256	Slovakia	SS
50	46.64285	24.81617	-390	-380	Romania	RR
51	43.62564	-0.93818	-649	-638	France	O
52	47.78719	7.506512	-853	-843	France	K

Source: Authors' contributions

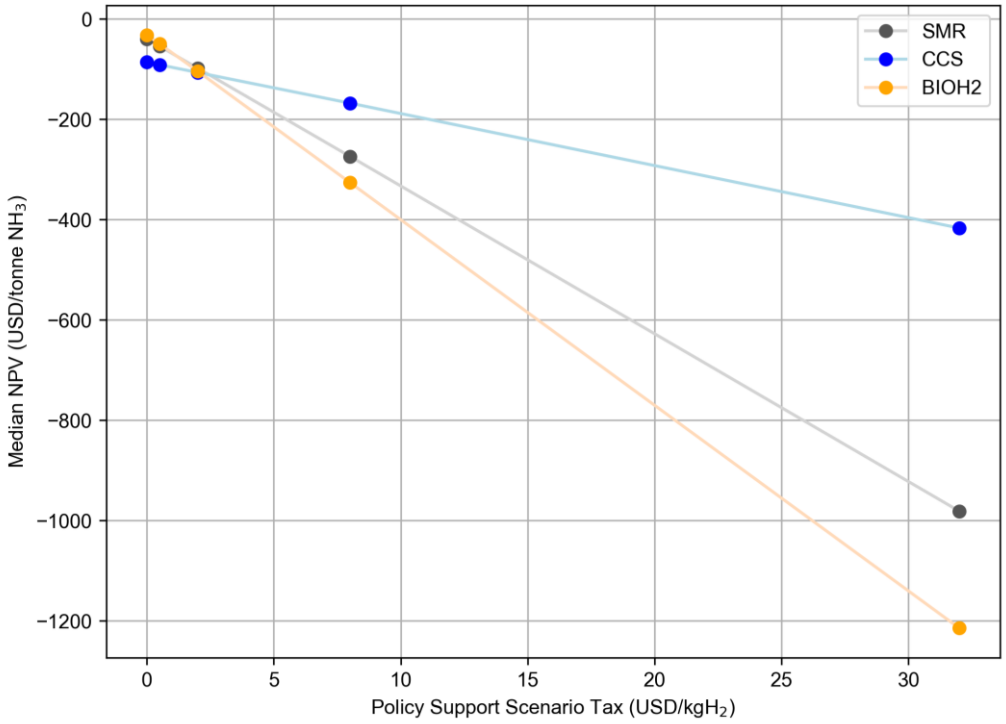
A6. Behaviour of NPV when Increasing Tax or Subsidy

Figure 21: Median NPV values of the renewable's pathway with different subsidy support



Source: Authors' contributions

Figure 22: Median NPV values of the SMR, CCS, and $BIOH_2$ pathways with different tax levels



Source: Authors' contributions

A7 Electricity Grid Hours in Monthly and Hybrid Matching and the Electricity Grid Fuel Split

Table 23: Electricity supply breakdown for renewable ammonia production in terms of in-situ generation and grid hours failing to meet the 90% CO_2 reduction requirement

Location	Country	Hours Met by in-situ Renewables (%)		Grid hours failing the 90% CO_2 reduction requirement (%)	
		2030	2040	2030	2040
A	Austria	45%	47%	29%	53%
B	Belgium	37%	39%	28%	50%
C	Belgium	40%	41%	29%	50%
D	Belgium	39%	40%	26%	48%
E	Bulgaria	34%	35%	21%	24%
F	Bulgaria	30%	29%	22%	27%
G	Croatia	41%	42%	26%	27%
H	Czechia	43%	44%	21%	37%
I	Finland	46%	47%	31%	45%
J	Finland	44%	45%	37%	51%
K	France	36%	37%	64%	63%
L	France	44%	45%	56%	55%
M	France	40%	41%	60%	59%
N	France	38%	40%	62%	60%
O	France	37%	39%	63%	61%
P	France	37%	38%	63%	62%
Q	France	50%	47%	50%	53%
R	Germany	30%	30%	3%	70%
S	Germany	43%	44%	15%	56%
T	Germany	43%	44%	17%	56%
U	Germany	43%	44%	16%	56%
V	Germany	43%	44%	17%	56%
W	Germany	46%	47%	17%	53%
X	Germany	49%	50%	17%	50%
Y	Germany	47%	49%	17%	51%
Z	Greece	36%	36%	16%	18%
AA	Hungary	39%	40%	21%	37%
BB	Italy	37%	37%	15%	35%
CC	Italy	35%	36%	15%	34%
DD	Lithuania	39%	41%	22%	59%
EE	Netherlands	41%	43%	27%	58%
FF	Netherlands	40%	41%	26%	59%
GG	Netherlands	45%	46%	28%	54%
HH	Norway	42%	43%	33%	51%
II	Norway	45%	45%	25%	43%
JJ	Poland	41%	42%	10%	33%

KK	Poland	37%	37%	9%	35%
LL	Poland	47%	49%	10%	30%
MM	Poland	38%	39%	9%	29%
NN	Poland	38%	39%	9%	29%
OO	Poland	41%	41%	8%	31%
PP	Poland	49%	50%	10%	30%
QQ	Portugal	51%	54%	24%	46%
RR	Romania	43%	44%	19%	20%
SS	Slovakia	37%	38%	22%	38%
TT	Spain	38%	39%	22%	61%
UU	Spain	32%	32%	23%	68%
VV	Spain	30%	29%	26%	71%
WW	Spain	36%	36%	19%	64%
XX	Spain	35%	36%	23%	64%
YY	UK	39%	41%	28%	44%
ZZ	UK	40%	42%	29%	44%

Source: Authors' contributions

Table 24: Electricity supply breakdown for renewable ammonia production in terms of in-situ generation and grid hours failing to meet the national target in CO_2 reduction requirement

Location	Country	Hours Met by in-situ Renewables (%)		Grid hours failing the national target in CO_2 reduction requirement (%)	
		2030	2040	2030	2040
A	Austria	45%	47%	23%	4%
B	Belgium	37%	39%	0%	19%
C	Belgium	40%	41%	0%	17%
D	Belgium	39%	40%	0%	20%
E	Bulgaria	34%	35%	0%	0%
F	Bulgaria	30%	29%	0%	0%
G	Croatia	41%	42%	0%	0%
H	Czechia	43%	44%	7%	4%
I	Finland	46%	47%	15%	19%
J	Finland	44%	45%	12%	17%
K	France	36%	37%	0%	0%
L	France	44%	45%	0%	0%
M	France	40%	41%	0%	0%
N	France	38%	40%	0%	0%
O	France	37%	39%	0%	0%
P	France	37%	38%	0%	0%
Q	France	50%	47%	0%	0%
R	Germany	30%	30%	31%	0%
S	Germany	43%	44%	3%	0%
T	Germany	43%	44%	4%	0%
U	Germany	43%	44%	3%	0%

V	Germany	43%	44%	3%	0%
W	Germany	46%	47%	3%	0%
X	Germany	49%	50%	2%	0%
Y	Germany	47%	49%	3%	0%
Z	Greece	36%	36%	0%	0%
AA	Hungary	39%	40%	10%	6%
BB	Italy	37%	37%	13%	0%
CC	Italy	35%	36%	14%	0%
DD	Lithuania	39%	41%	0%	0%
EE	Netherlands	41%	43%	0%	0%
FF	Netherlands	40%	41%	0%	0%
GG	Netherlands	45%	46%	0%	0%
HH	Norway	42%	43%	17%	22%
II	Norway	45%	45%	21%	28%
JJ	Poland	41%	42%	0%	0%
KK	Poland	37%	37%	0%	0%
LL	Poland	47%	49%	0%	0%
MM	Poland	38%	39%	0%	0%
NN	Poland	38%	39%	0%	0%
OO	Poland	41%	41%	0%	0%
PP	Poland	49%	50%	0%	0%
QQ	Portugal	51%	54%	0%	1%
RR	Romania	43%	44%	0%	0%
SS	Slovakia	37%	38%	9%	5%
TT	Spain	38%	39%	0%	2%
UU	Spain	32%	32%	0%	4%
VV	Spain	30%	29%	0%	3%
WW	Spain	36%	36%	0%	8%
XX	Spain	35%	36%	0%	3%
YY	UK	39%	41%	0%	4%
ZZ	UK	40%	42%	0%	3%

Source: Authors' contributions

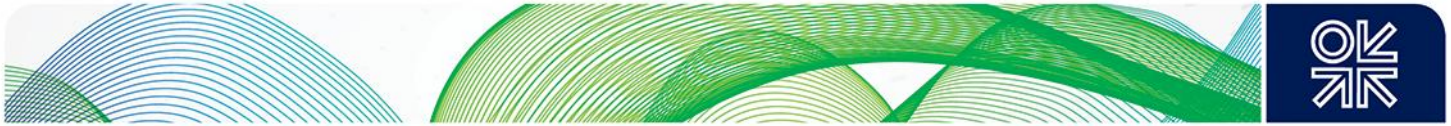


Table 25: The electricity grid split for the considered countries by 2030 and 2040

Country	Clean grid (%)	Utility Solar PV (%)	Wind Offshore (%)	Wind Onshore (%)	Tidal (%)	Residential Solar PV (%)	Geothermal (%)	Hydro (%)	CCGT (%)	CCGT H2 (%)	CCGT CCS (%)	Coal Bit CCS (%)	Coal Bit(%)	Lignite (%)	Lignite CCS (%)	Oil (%)	Biomass (%)	Biomass CCS (%)	Nuclear (%)
2030																			
Austria	89.1	0.3	0.0	8.3	0.0	5.8	0.0	55.3	8.1	0.0	0.0	0.0	0.7	2.1	0.0	0.0	15.0	0.0	4.4
Belgium	74.9	0.2	10.5	18.2	0.1	17.8	0.0	0.6	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6	0.1	22.9
Bulgaria	74.2	13.6	0.5	16.0	0.0	6.4	0.0	24.5	16.7	0.0	0.0	0.0	4.2	4.9	0.0	0.2	1.6	0.0	11.7
Croatia	74.2	13.6	0.5	16.0	0.0	6.4	0.0	24.5	16.7	0.0	0.0	0.0	4.2	4.9	0.0	0.2	1.6	0.0	11.7
Czechia	77.2	4.9	0.0	6.2	0.0	7.9	0.0	6.7	8.8	0.0	0.0	0.0	0.0	14.0	0.0	0.0	6.0	0.0	45.5
Finland	87.4	1.1	2.6	16.7	0.0	3.0	0.0	25.9	4.6	0.0	0.0	0.0	7.9	0.0	0.0	0.1	8.5	0.1	29.7
France	97.7	3.0	1.7	11.3	0.0	3.5	0.1	13.3	2.2	0.0	0.0	0.0	0.1	0.0	0.0	0.0	4.6	0.0	60.2
Germany	66.9	4.7	7.3	29.3	0.0	12.0	0.0	3.0	6.0	0.0	0.0	0.0	14.4	12.7	0.0	0.0	10.6	0.0	0.0
Greece	74.2	13.6	0.5	16.0	0.0	6.4	0.0	24.5	16.7	0.0	0.0	0.0	4.2	4.9	0.0	0.2	1.6	0.0	11.7
Hungary	77.2	4.9	0.0	6.2	0.0	7.9	0.0	6.7	8.8	0.0	0.0	0.0	0.0	14.0	0.0	0.0	6.0	0.0	45.5
Italy	76.2	7.1	1.1	7.2	0.0	25.7	0.4	19.9	23.7	0.0	0.0	0.0	0.0	0.0	0.0	0.1	14.8	0.0	0.0
Lithuania	60.3	13.3	4.3	20.6	0.0	2.9	0.0	13.9	13.7	0.0	0.0	0.0	25.9	0.0	0.0	0.0	5.4	0.0	0.0
Netherlands	73.0	4.6	18.0	24.2	0.0	19.9	0.0	0.1	16.1	0.0	0.0	0.0	10.9	0.0	0.0	0.0	4.4	0.0	1.9
Norway	87.4	1.1	2.6	16.7	0.0	3.0	0.0	25.9	4.6	0.0	0.0	0.0	7.9	0.0	0.0	0.1	8.5	0.1	29.7
Poland	32.5	5.5	0.8	12.1	0.0	7.5	0.0	1.5	9.1	0.0	0.0	0.0	53.0	5.4	0.0	0.0	5.0	0.0	0.0
Portugal	77.2	23.3	0.0	16.3	0.0	5.9	0.0	18.1	17.0	0.0	0.0	0.0	5.8	0.0	0.0	0.1	2.4	0.0	11.1
Romania	74.2	13.6	0.5	16.0	0.0	6.4	0.0	24.5	16.7	0.0	0.0	0.0	4.2	4.9	0.0	0.2	1.6	0.0	11.7
Slovakia	77.2	4.9	0.0	6.2	0.0	7.9	0.0	6.7	8.8	0.0	0.0	0.0	0.0	14.0	0.0	0.0	6.0	0.0	45.5
Spain	77.2	23.3	0.0	16.3	0.0	5.9	0.0	18.1	17.0	0.0	0.0	0.0	5.8	0.0	0.0	0.1	2.4	0.0	11.1
UK	71.6	1.7	14.2	15.1	0.0	1.0	0.5	19.6	28.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.0	16.6
2040																			
Austria	93.3	0.5	0.0	4.6	0.0	8.3	0.0	74.1	6.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	0.0	3.6
Belgium	91.8	0.2	13.7	29.9	0.0	23.0	0.0	0.6	8.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	9.8	14.0
Bulgaria	75.9	21.5	0.2	15.8	0.0	3.6	0.0	22.6	23.8	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.8	1.2	10.2
Croatia	75.9	21.5	0.2	15.8	0.0	3.6	0.0	22.6	23.8	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.8	1.2	10.2
Czechia	84.3	10.7	0.0	4.0	0.0	15.7	0.0	10.8	15.3	0.0	0.0	0.0	0.0	0.3	0.0	0.0	1.2	0.0	41.8
Finland	93.1	1.6	8.5	9.2	0.0	3.7	0.0	39.6	6.7	0.0	0.0	0.0	0.2	0.0	0.0	0.0	4.4	2.6	23.5
France	94.3	4.1	8.1	19.9	0.0	2.2	0.0	8.8	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.3	50.3
Germany	90.7	7.5	14.9	59.0	0.0	6.0	0.0	1.8	9.0	0.0	0.0	0.0	0.2	0.1	0.0	0.0	1.2	0.3	0.0
Greece	75.9	21.5	0.2	15.8	0.0	3.6	0.0	22.6	23.8	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.8	1.2	10.2
Hungary	84.3	10.7	0.0	4.0	0.0	15.7	0.0	10.8	15.3	0.0	0.0	0.0	0.0	0.3	0.0	0.0	1.2	0.0	41.8
Italy	83.6	11.6	5.5	6.6	0.0	42.2	0.2	15.5	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.2	0.0
Lithuania	92.8	32.1	17.5	28.3	0.0	1.7	0.0	10.9	6.9	0.0	0.0	0.0	0.4	0.0	0.0	0.0	1.8	0.5	0.0
Netherlands	94.8	5.2	48.9	30.3	0.0	8.0	0.0	0.0	5.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.4	0.8	1.1
Norway	93.1	1.6	8.5	9.2	0.0	3.7	0.0	39.6	6.7	0.0	0.0	0.0	0.2	0.0	0.0	0.0	4.4	2.6	23.5
Poland	76.3	18.5	15.9	30.2	0.0	6.3	0.0	3.5	22.3	0.0	0.0	0.0	1.2	0.2	0.0	0.0	1.2	0.7	0.0
Portugal	92.2	38.1	0.0	28.8	0.0	3.0	0.0	12.8	7.7	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.9	0.3	8.3
Romania	75.9	21.5	0.2	15.8	0.0	3.6	0.0	22.6	23.8	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.8	1.2	10.2
Slovakia	84.3	10.7	0.0	4.0	0.0	15.7	0.0	10.8	15.3	0.0	0.0	0.0	0.0	0.3	0.0	0.0	1.2	0.0	41.8
Spain	92.2	38.1	0.0	28.8	0.0	3.0	0.0	12.8	7.7	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.9	0.3	8.3
UK	86.3	2.1	7.7	9.5	0.0	1.1	0.3	49.7	13.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	3.9	10.9

Source: Computed based on data from [81]