Green hydrogen export opportunities for African countries

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Abstract

Governments in many European countries have high hopes in cheap green hydrogen (H_2) from Africa to decarbonize hard-to-abate sectors. This study leverages GeoH2, a geospatial levelized cost of hydrogen model, to evaluate the economic feasibility of exporting green H_2 from Africa to Europe under four realistic financing scenarios. Our findings suggest that without European policy interventions, the median costs for African green H_2 exports are prohibitive, ranging from €10.4/kg_{H2} to €12.2/kg_{H2}, 2-3 times above projected European costs. De-risking can lower median costs to €6.7/kg_{H2} in a low interest rate environment, with least cost locations at €3.6/kg_{H2} in Mauritania. In the current interest rate environment, we identify locations in ten African countries that may be competitive, yet many of these are prone to conflict or instability casting doubt on long-term investments. To reduce cost further, lowering the cost of finance and the cost of wind energy is critical, rather than shipping costs. Overall, de-risking and strategic location selection are key to make African green H_2 exports competitive on the global stage.

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Introduction

In 2022, 99% of hydrogen (H_2) was produced using fossil fuels. This "grey" H_2[1] mainly serves demand from the refining and industrial sectors. Achieving net zero requires a change to "green" H_2 using renewable energy (RE) to meet current demand at low emissions (e.g., chemicals) and to decarbonize further hard-to-abate sectors, such as steel production. Decarbonizing such hard-to-abate sectors is projected to cause an almost sixfold increase in global H_2 demand by 2050[1].

However, deploying green H_2 at scale will require market-competitive costs. As of 2022, green H_2 constituted a mere 0.1% of global H_2 production[1], with costs 2-3 times higher than grey H_2[2,3]. To become competitive, technical and operational reductions could be pursued, projected at up to 85% cost reductions through lower-cost renewable electricity, reduced electrolyser costs, enhanced electrolyser efficiency, and optimized operating hours[2]. Additionally, shifting green H_2 production to more cost-efficient locations with better availability of RE, including overseas[4,5], could increase its competitiveness against other hydrogen types.

The European Union (EU) explicitly supports the creation of such green H_2 export markets and aims to import 10MT of green H_2 for decarbonization[6]. Over 70 potential supply regions, many in Africa[7] due to often abundant RE, have been identified, and bilateral agreements have already been signed, e.g., with Namibia[8]. African countries start implementing domestic policies too with countries like Namibia, South Africa, Morocco, and Kenya developing strategies focused on export[9].

Despite EU and African green H_2 ambitions, a geospatial analysis providing realistic cost estimates for African green H_2 export is missing. Geospatial modelling including variable capital expenditure (CAPEX) or energy cost[10] is commonly used to inform policymakers on the economic viability of different green H_2[11] production locations. Yet, these models typically use a uniform financing cost or cost of capital (COC) set to 4-8%[10,12,13], which is problematic when estimating green H_2 costs, as energy infrastructure research indicates large variations in COC across Africa[14]. The few studies which account for these variations leverage data from the oil and gas sector[15] or country-specific ratings[16–18], which do not adequately represent the specific risks associated with green H_2 investments and lack empirical calibration. Consequently, current modelling risks producing overly optimistic green H_2 levelized cost of hydrogen (LCOH) estimates for export due to inaccurate representation of their investment and policy environments[19]. Given the existing

North-South power disparity, this is ever more concerning because it could result in unviable infrastructure investments and stranded assets without development benefits in African countries.

Here we estimate COC across potential green H_2 exporters in Africa for four realistic financing scenarios and use these to calculate LCOH. Differentiating COC by country, financing structure, and interest rate environment – verified through expert interviews – we optimize green H_2 production locations using GeoH_2[12,13]. This novel geospatial least-cost model optimizes production, transport, storage, and conversion using granular spatial data. NH_3 is utilized as a vector for green H_2 transport and conversion to minimize costs. Through the analysis, the economic viability of green H_2 export projects on the African continent is investigated considering realistic financing scenarios.

Planned green H_2 capacity

To understand the status of green H_2 development on the African continent, we identified all projects planned to be operational by 2030. We restricted the analysis to African countries with port access, as landlocked countries would need to negotiate agreements to secure transportation to ports, introducing further complexity and uncertainty. Somalia and Libya are excluded due to political instability, and small island states are excluded due to infrastructure and space constraints, resulting in a sample of 31 countries (see Methods). 34 projects are found across seven countries (see Figure 1), 89% of which are either at concept or feasibility stages, two projects have reached a financial investment decision and are under construction, and only one small-scale project (i.e., 3.5MW) in South Africa is operational. Planned project sizes vary from 3.5MW to 6.9GW. While Egypt and South Africa have numerous smaller projects planned, Mauritania has three large projects planned, totalling 7GW of capacity. This includes giga-scale projects Nour and Aman, two of the largest planned H_2 export projects globally[20,21].

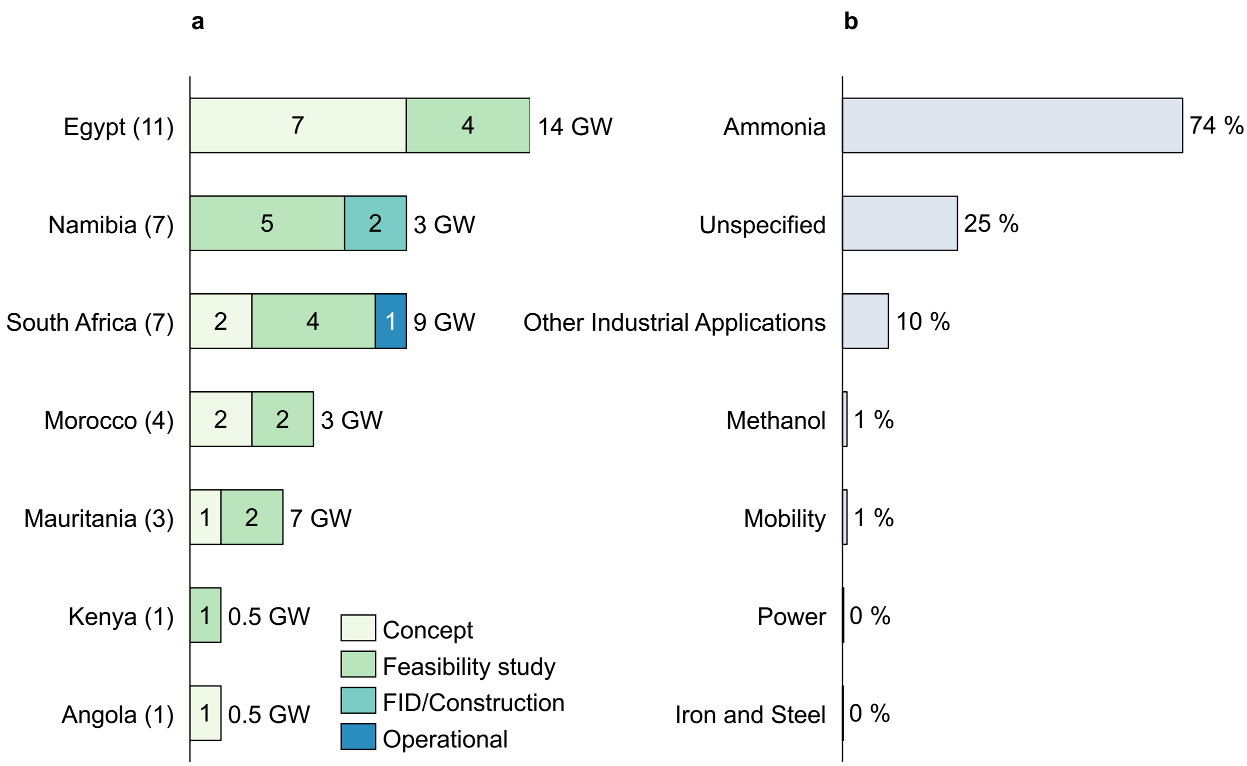

Fig. 1 | Overview of African green hydrogen projects by country and end-use. a. Number of projects by project status (bars) and the sum of planned capacity by country (bar labels). **b**. Share of planned standardized electrolyser capacity. Only projects planned to go online by 2030 are included. Projects can have more than one end-use; hence, shares in 1b add up to 112%. Information on local versus export end-use is unavailable. Note that capacity figures were not available for two planned projects in Mauritania and Morocco. See Methods for data sources and details on sample selection. Data as of November 2023.

Figure 1 shows that 74% of planned electrolyser capacity is intended for NH_3 production. NH_3 offers advantages as a H_2 carrier for long-distance transport, including higher energy density compared to gaseous or liquid H_2, and avoiding the boil-off rate of liquefied H_2[22,23]. Moreover, unlike gaseous or liquid H_2, international trade networks for NH_3 are well-established, so existing port facilities and trade routes can be utilized for shipping. For the remainder of this paper, we therefore analyse the economic viability of exporting green H_2 by producing NH_3, maintaining this state for transport and shipping, and converting the NH_3 to H_2 upon import.

Cost of Capital

To date, only three green H_2 deals have reached financial closure on the African continent, as shown in Figure 1. Consequently, it is impossible to draw on empirical data regarding the COC for green H_2 projects. Therefore, we developed four financing scenarios shown in Table 1, estimated the COC for each, and triangulated the approach through 12 semi-structured expert interviews conducted February-September 2023 (see Methods). The scenarios are defined based on two dimensions: the general interest rate environment (reflecting the risk-free rate) and the policy environment. On interest rate, we depict an *investment-friendly* world with low general interest rates reflective of the five-year average Federal Funds Rate (FED rate) between the financial crisis in 2008 until 2013 and a *cash-constrained* world reflective of the FED rate in September 2023[24]. For policy, we contrast a *de-risked* scenario, where European policymakers issue a complete price and off-taker guarantee to lower investment risk, with a *commercial* scenario, where investment risk lies entirely with the project sponsor. The COC in the de-risked scenario differs by country despite identical off-take guarantees because, based on expert interviews, we assume projects require insurance against expropriation and war by the World Bank Group (see Methods on operationalizing scenarios).

Table 1 │ Financing scenarios. We differentiate financing scenarios by the general interest rate environment (rows) and the policy environment (columns). Scenario 1, *cash-constrained private*, features the highest COC in the absence of an offtake guarantee where private project sponsors bear all risk and face a high-interest rate environment. Scenario 2, *cash-constrained de-risked*, features a lower COC because European governments provide an offtake guarantee, lowering investment risk. Scenario 3, *investment-friendly private*, features a lower COC than scenario 1 because of the low-interest rate environment, but risks are assumed by the project sponsor in contrast to scenario 2. Finally, scenario 4, *investment-friendly de-risked,* features the lowest COC with an offtake guarantee by European governments in a low general interest rate environment. We use a risk-free rate of 2% in the low and 5% in the high interest rate environment. For more details on the scenarios, see Methods.

	Private commercial	**Public de-risked**
High general interest rate	1 *Cash-constrained private*	2 *Cash-constrained de-risked*
Low general interest rate	3 *Investment-friendly private*	4 *Investment-friendly de-risked*

Figure 2 shows the calculated COC for green H_2 projects, including investment into dedicated renewable generation and transport infrastructure, for scenarios 1 and 2. These are most representative of the current macroeconomic environment where interest rates are relatively high, and they illustrate the de-risking effect of offtake guarantees by European governments. Data on scenarios 3 and 4 are provided in Supplementary Figure 1.

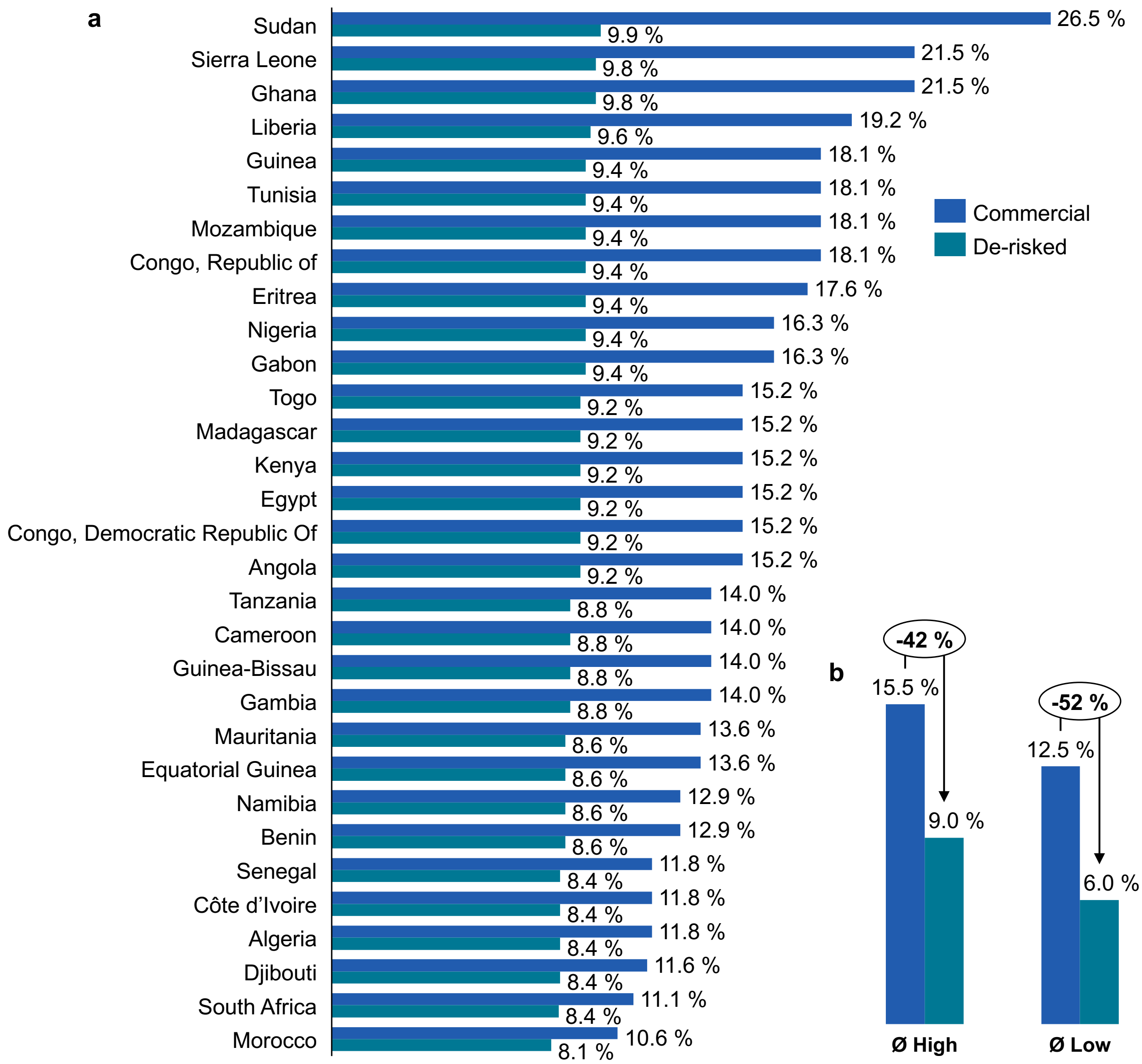

Fig. 2 | Cost of capital (COC) by country and policy scenarios. a. COC for a private commercial and a public de-risked scenario in a high general interest environment (scenarios 1 and 2). **b.** Average COC for all scenarios. Country COC for a low-interest rate environment is provided in Supplementary Figure 1. Country differences result from different investment risks based on default spreads[25], while differences between policy scenarios – commercial versus de-risked – are the result of different sources of capital and premia (see Methods).

Figure 2 shows the large variance in commercial COC across the sampled countries, from 26.5% in Sudan to 10.6% in Morocco with an average of 15.5%. De-risking projects has two effects. First, it lowers the COC for all countries to 9.0% on average (a 42% reduction). This improves the economic viability of green H_2 substantially as shown in subsequent analyses (Figures 3–5). Second, de-risking reduces the variance of COC across countries. Whereas in the commercial scenario, COC varies by 15.9%-points across countries, this variance reduces to 1.9%-points in a de-risked scenario. Hence, de-risking acts as a leveller, bringing green H_2 costs across different countries much closer together.

Finally, the absolute de-risking effect amounts to 5%-points, irrespective of the interest rate environment (Figure 2b), which translates into a relative reduction of 52% in a low-interest rate scenario. Hence, the policy effect of 5%-points exceeds the difference between the two interest rate scenarios of 3%-points, and the combined difference of policy and interest rate environment amounts to a staggering 8%-points (average difference between scenario 1 and 4).

Levelized cost of exported green H_2

The GeoH2 model is employed to calculate the LCOH achievable in each country by optimising location-specific production, transport, storage, and conversion. The greenfield cost of NH_3 production from renewable electricity is modelled for 11,383 hexagons (~1,770 km^2) covering the 31 sample countries (see Methods). A plant size of 37.2 GW, the median size of African projects with a planned operation by 2030, is modelled (see Figure 1). Hourly solar and wind data is used to optimize solar PV, onshore wind, battery storage, electrolysis, H_2 storage, and NH_3 storage, subject to realistic technical constraints (see Methods). We assume the NH_3 is transported from the production location to the closest domestic port and shipped to Rotterdam, where it is converted into green H_2. Pipeline and trucking transport to the port are considered; the cheapest option is selected for each hexagon. Shipping costs to Rotterdam are calculated per distance based on the literature (see Methods). LCOH is calculated for each hexagon using country-specific COC values (e.g., as in Figure 2) for the four scenarios in Table 1. The results are contrasted with a European green H_2 cost estimate inferred from our model and triangulated with values from literature.

Figure 3 shows the resulting LCOH distribution across the sampled coastal African countries under each financing scenario. In a high-interest environment (scenarios 1 and 2), median costs for green H_2 exported from Africa are €12.2/kg_{H2} without policy support and €8.2/kg_{H2} when fully de-risked by European governments. In a low-interest environment (scenarios 3 and 4), these costs come down to €10.4/kg_{H2} and €6.7/kg_{H2}, respectively. Irrespective of the scenario, these costs are much higher than estimates for European green H_2 by 2030, roughly in the range of €3-5/kg_{H2} (see Methods). These results also demonstrate the importance of de-risking, which reduces median costs by €3.85/kg_{H2} (average between high- and low-interest environment), whereas low interest rates reduce median costs by another €1.65/kg_{H2} (average between no policy support and de-risking).

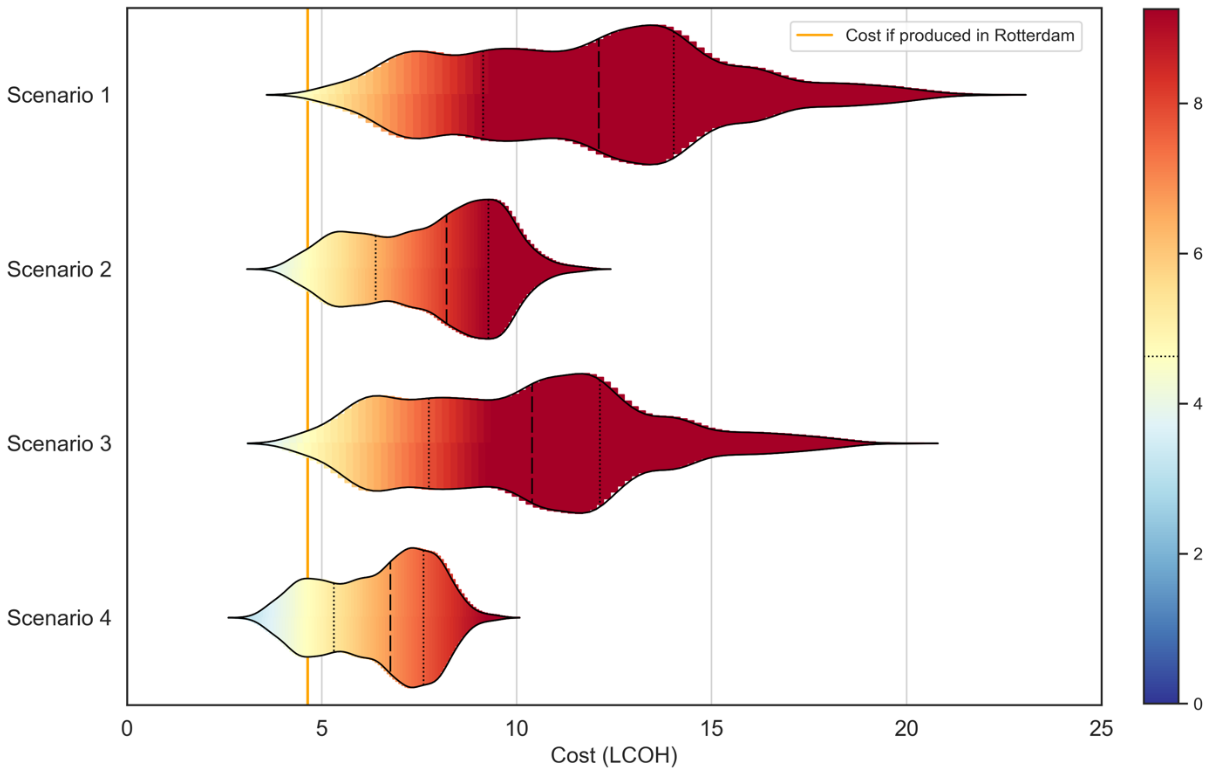

Fig. 3 | LCOH distribution by scenario. Each violin plot shows the distribution of LCOH from all modelled locations in Rotterdam. The width of the violin indicates the density of the distribution. Scenarios are defined as shown in Table 1. The orange line represents the cost of producing green H_2 in Rotterdam by 2030 as described in Methods. Colours indicate the cost competitiveness with European green H2 projects, where blue is "in the money" compared to the cost of green hydrogen produced in Rotterdam. The dotted line on the colour bar denotes the mean modelled cost of hydrogen produced in Rotterdam across the four scenarios. LCOH is in €/kg. Dashed black lines within the violin plots indicate the median, and dotted black lines indicate the 25th and 75th percentiles. See Supplementary Table 2 for exact values.

Although there are some low-cost production locations in Africa, achieving cost competitiveness with European green H_2 is challenging. In the current high-interest macroeconomic environment, cost-competitive production (i.e., below costs in Rotterdam estimated at 4.6/kg_{H2} with slight variations according to scenarios, see Methods) is largely unattainable without de-risking—only 0.2% of all modelled locations can supply cost-competitive green H_2 to Europe. With de-risking, this increases to 6.2%, with locations in Algeria, Mauritania and Morocco among others. In a low-interest rate environment, the proportions of locations reaching cost-competitiveness without de-risking increases to 2.1% (20.4% with de-risking). Therefore, de-risking and strategic location selection are crucial to ensure that green H_2 exported from Africa to Europe can be cost-competitive.

De-risking not only increases the number of cost-competitive African locations, but also narrows the cost distribution substantially across countries. Costs range from €4.7-22.1/kg_{H2} without de-risking in the current macroeconomic environment but only from €3.6-11.9/kg_{H2} with de-risking. Irrespective of the interest rate environment, the lowest cost location of green H_2 production without de-risking is in Morocco (€4.7/kg_{H2}), due to its relatively good institutional quality, exceptional wind resources, and relative proximity to Rotterdam. With de-risking, the lowest cost location shifts to Mauritania (€3.6/kg_{H2}). While Mauritania shares Morocco's advantages in wind resources and proximity to Europe, it lacks institutional quality, reflected in its higher COC compared to Morocco (i.e., 13.6% versus 10.6% without de-risking, 8.6% versus 8.1% with de-risking).

The LCOH distribution for each country is shown in Figure 4 for scenarios 1 and 2, reflecting the current high-interest rate environment. Scenarios 3 and 4 are in Supplementary Figure 2. When European countries de-risk projects (Figure 4a), ten African countries approach cost competitiveness: Mauritania, Algeria, Sudan, Egypt, Morocco, Namibia, Djibouti, Senegal, Kenya, and South Africa. Without de-risking, only some locations in Mauritania, Algeria, and Morocco remain competitive.

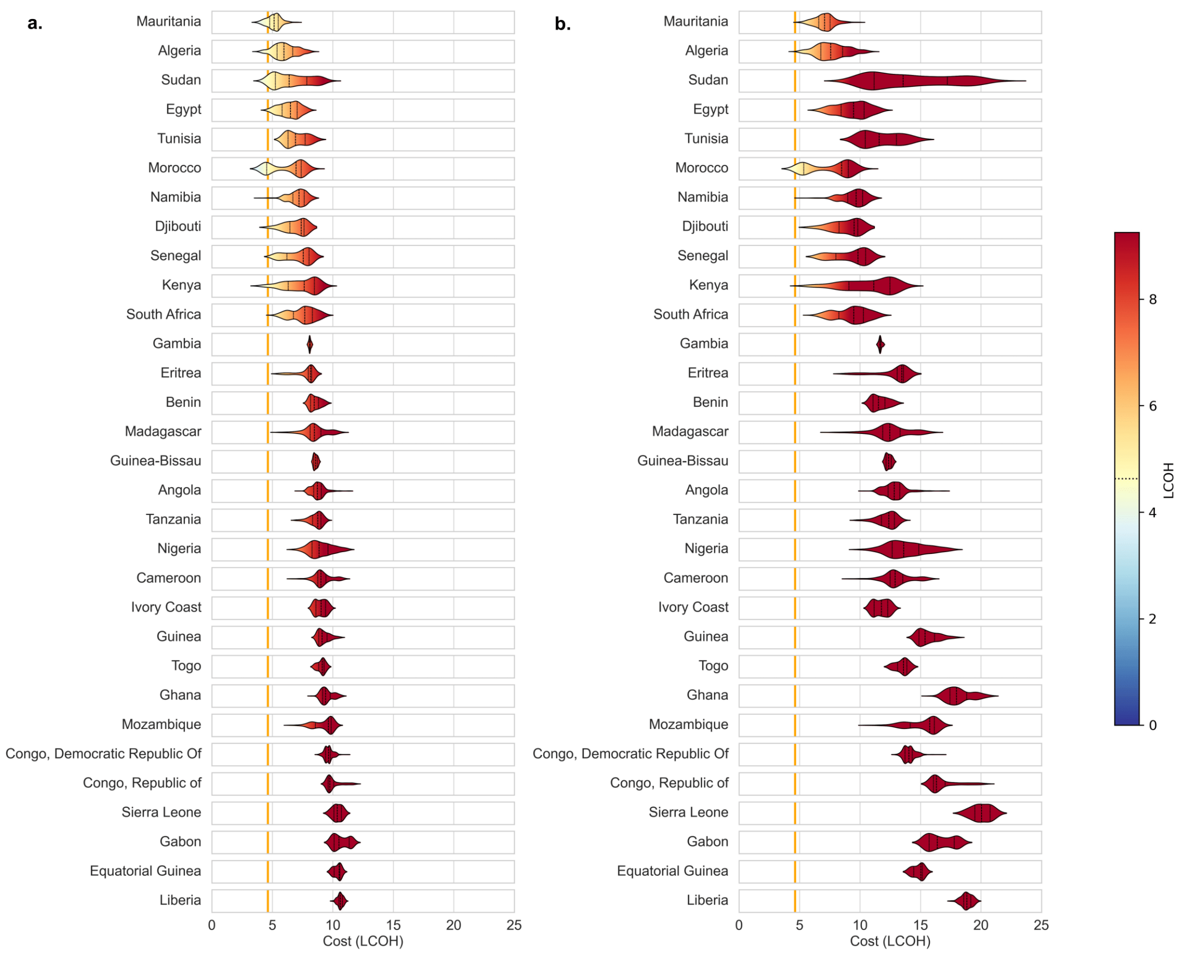

Fig. 4 | LCOH distribution by country. a. LCOH for scenario 2, *cash-constrained de-risked.* **b.** LCOH for scenario 1, *cash-constrained commercial*. Countries are ordered by median LCOH in scenario 2. The orange line represents the cost of producing green H2 in Rotterdam by 2030 as described in Methods. Colours indicate the cost competitiveness with European green H_2 projects, where blue is "in the money" compared to the cost of hydrogen produced in Rotterdam, yellow is near the European cost, and red is likely to be uncompetitive. The dotted line on the colour bar denotes the mean modelled cost of hydrogen produced in Rotterdam across the four scenarios. LCOH is in €/kg. Dashed black lines within the violin plots indicate the median and dotted black lines indicate the 25th and 75th percentiles.

To further clarify spatial cost variance, Figure 5 maps continent-wide LCOH for scenarios 1 and 2 alongside planned project locations (see Supplementary Figure 3 for scenarios 3 and 4). Most low-cost regions are north of the Equator, with some in the Southern Hemisphere. Equatorial costs are high due to moderate wind resources and consistent cloud cover, increasing RE cost and thus LCOH. We identify optimal green H_2 production locations in the Western Sahara (Morocco), Mauritania, Central Algeria, at the Sudanese-Egyptian border, and Lake Turkana's shores at the Kenyan-Ethiopian border. Some coastal areas in Namibia and South Africa also exhibit low costs.

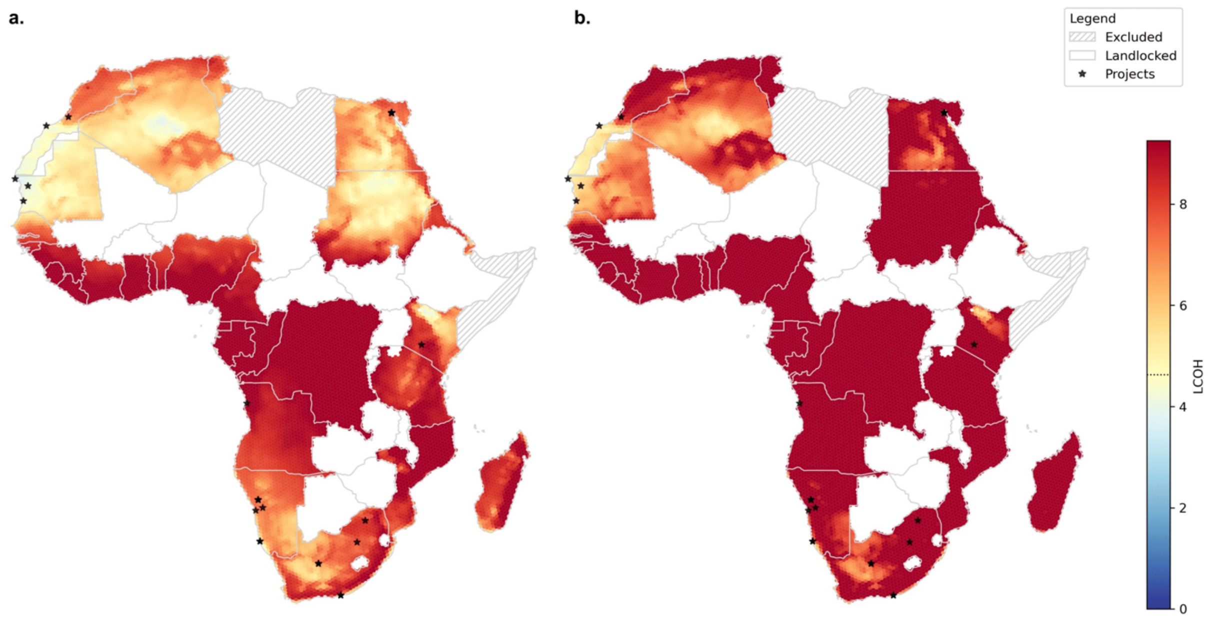

Fig. 5 | LCOH for Africa. a. LCOH for scenario 2, *cash-constrained de-risked.* **b.** LCOH for scenario 1, *cash-constrained commercial*. Colours indicate the cost competitiveness with European green H_2 projects, where blue is "in the money" compared to the cost of hydrogen produced in Rotterdam, yellow is near the European cost, and red is likely to be uncompetitive. The dotted line on the colour bar denotes the mean modelled cost of hydrogen produced in Rotterdam across the four scenarios. LCOH in €/kg H_2. Stars denote planned projects, as listed in Figure 1.

While the geographic spread of potentially feasible locations may initially seem promising, many of these locations face obstacles to the large-scale and long-term investments needed to produce green H_2. The Western Sahara, Central Algeria, the Sudanese-Egyptian border, and the Kenyan-Ethiopian border are either politically contested or encounter regular flares of armed conflict. Indeed, the UK government advises against travel to Sudan (entire territory), Western Sahara (partly), Mauritania (partly), Algeria (border areas), and Ethiopia (border areas, including to Kenya) as of December 2023[26]. While beyond the scope of this paper, future analyses could consider investment risk variations within countries, including in specific regions with severe political instabilities. The size of the investments needed may also impact feasibility in these regions. For example, as of 2021, the GDP of Mauritania is roughly US$10 billion; however, the planned green H_2 project Aman is estimated to require an investment of US$40 billion, four times the country's GDP[27,28]. The size of the investment relative to the country's GDP makes it disputable whether such a project is feasible.

Examining countries with planned projects above 1MW, shown in detail in Figure 6, reveals location-specific nuance. For Namibia and South Africa, low-cost production sites are coastal and near ports, boding well for export. In Egypt, however, more politically stable parts, like the Red Sea or near the river Nile, may face challenges of water insecurity potentially disrupting consistent production. While water costs are considered in GeoH2, the potential for water depletion and associated conflict risks is not at present.

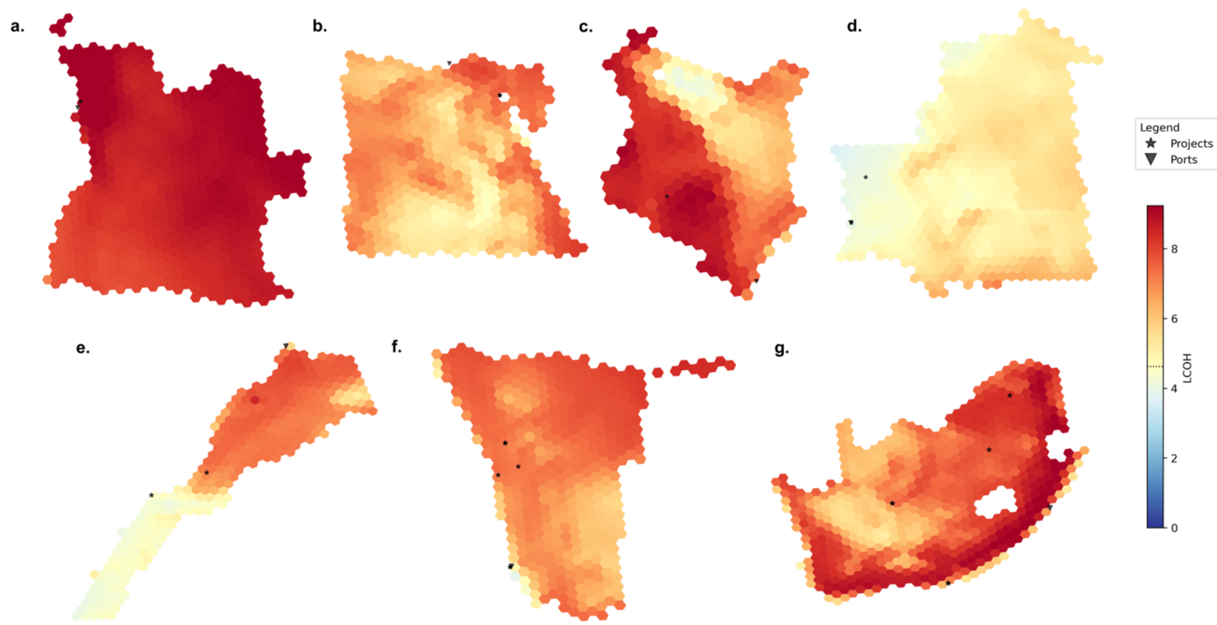

Fig. 6 | Granular LCOH for countries with planned projects. LCOH maps for **a.** Angola, **b.** Egypt, **c.** Kenya, **d.** Mauritania, **e.** Morocco, **f.** Namibia, and **g.** South Africa. The costs shown are for scenario 2, *cash-constrained de-risked.* For scenario 1, see Supplementary Figure 4. Countries are not shown to scale to improve readability, each hexagon is the same area across all sub-figures.

To increase the number of cost-competitive African green H_2 production locations, cost drivers and cost-reduction levers must be identified. To this end, a detailed cost breakdown for the least-cost green H_2 location by country is provided in Figure 7. This figure shows that the lowest LCOH is achieved by leveraging excellent onshore wind resources, which facilitate lower-cost green H_2 production than solar PV systems due to their more consistent electricity output. Scrutinizing the temporal optimisation results, we find that NH_3 and compressed H_2 storage are used to balance intermittent RE generation and demand more cost-competitively than battery storage in all examined countries' least-cost production locations (see Supplementary Figure 5). Nevertheless, more consistent wind resources reduce the expenditure required for any form of storage, driving down costs.

Figure 7 also shows that RE investment constitutes the largest cost component for all countries. This points to two levers for cost reductions. Firstly, lowering RE costs would directly reduce the cost of green H_2. This could potentially enhance the cost-competitiveness of African green H_2 exports, depending on concurrent impacts on European electricity prices. Secondly, efficient de-risking (i.e., maximally reducing the COC) can lower COC-intensive investments into renewables and consequently green H_2 costs. While movements in the general interest rate would only affect the cost competitiveness of African projects compared to European ones to the extent that African projects are more capital-intensive because they require greenfield RE, strong de-risking would improve the cost competitiveness of African projects directly. Finally, shipping costs are shown to have a marginal impact on LCOH. This suggests that potential economies of scale in NH_3 shipping or repurposing existing pipelines from Northern Africa to Southern Europe may not significantly enhance cost competitiveness of African green H_2. On the upside, this indicates that uncertainties around NH_3 shipping costs should not constitute a major impediment to planning green H_2 export projects in African countries.

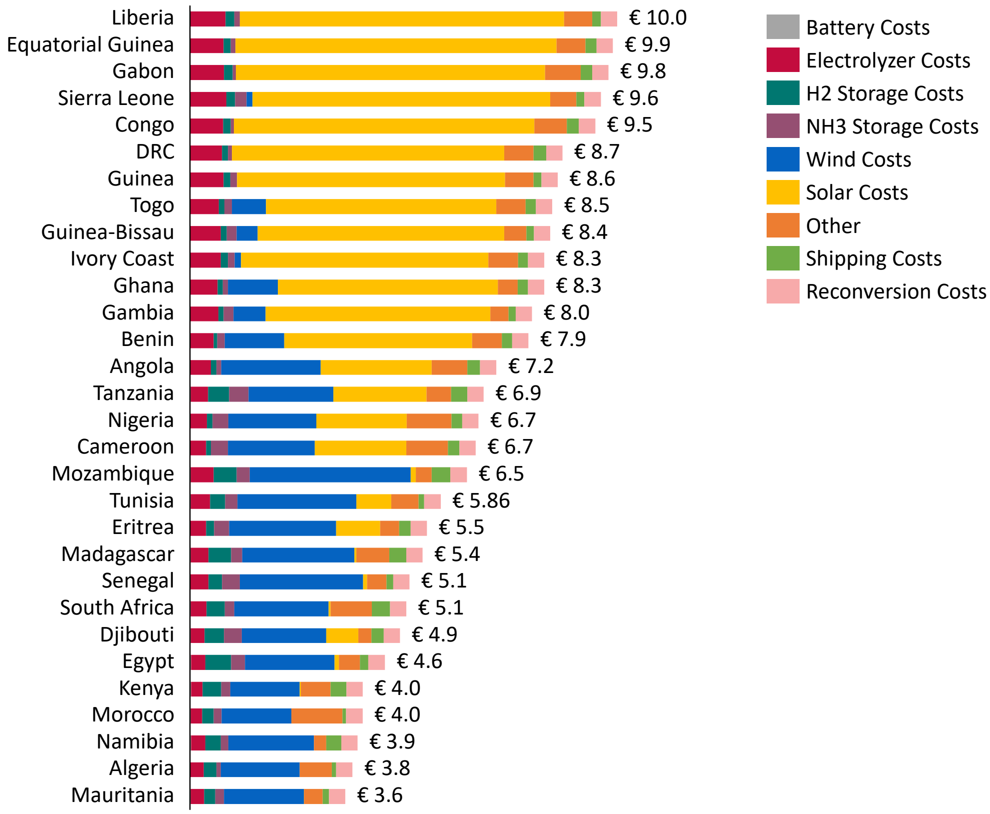

Fig. 7 | LCOH breakdown for least-cost locations. Cost shown in €/kg green H_2 for the least-cost location in each country under scenario 2, *cash-constrained de-risked.* For scenario 1, see Supplementary Figure 6. “Other” contains costs for H_2 compression and decompression, trucking transportation, battery interface, Haber-Bosch process, H_2 fuel cell, and a ramping penalty.

Discussion

Our findings indicate that using African green H_2 to decarbonize hard-to-abate sectors in Europe might be unrealistic without de-risking from European countries. In a commercial scenario, cost-competitive pockets comprise just 0.16% of all locations studied situated in Algeria, Mauritania, and Morocco. However, de-risking increases the number of cost-competitive locations to include Algeria, Djibouti, Egypt, Kenya, Mauritania, Morocco, Namibia, or Sudan (6.2% of all locations studied). Hence, de-risking is likely necessary to develop a market with a sufficient portfolio of potential locations.

Results also illuminate potential issues beyond cost which could hinder investment. First, while we find that wind resources are critical to low-cost green H_2 production, local expertise to install this wind capacity may be insufficient. For context, there were 7.7 GW of installed wind capacity on the continent in 2022 (versus 12.5 GW of solar PV)[14]; meanwhile, wind plants on GW-scale will be needed for each H_2 production sites (e.g., up to 1.6 GW in Morocco), likely requiring massive upskilling efforts. Second, we find that many low-cost production regions are unstable and prone to conflict. Multilateral Investment Guarantee Agency (MIGA) or off-taker guarantees are likely unavailable in these areas, limiting de-risking potential. Third, the magnitude of the proposed investments may burden African countries with massive foreign debt[29] (e.g., the case of Mauritania), depending on the planned investment structure.

African countries will face global competition for cheap green H_2 production. Countries such as Chile[30], Oman[31], and Saudi Arabia[1] plan to expand production of H_2 and downstream products (e.g., iron). These countries have the domestic financial resources to fund infrastructure development, institutional frameworks to attract large international private investment, and strategic locations along major international trading routes. European countries such as Spain also offer favourable H_2 production costs, low COC and supply costs, and proximity to consumer countries[16]. Tailored de-risking support from international organizations, such as the World Bank or UNDP[32,33], may therefore be necessary for African nations to compete. The use of such support tools should be contingent on the provision of benefits of green H_2 production for local economies beyond export revenues only.

Similarly, African countries should consider such benefits in bilateral negotiations with prospective green H_2 importers. Considering the prospects for local industrial use of green H_2 (e.g., in creating value-added downstream products) when designing policy support schemes may favour countries like Morocco, Egypt, South Africa, or Kenya, in contrast to Mauritania or Namibia, which have a weaker industrial base. If projects are designed for both local use and export use, securing off-taker guarantees could be more challenging, as the viability of the plant depends on the local economy. International organizations may consider assuming the risk for local use in such cases. While potentially more challenging, such multi-use projects may improve developmental impacts and avoid neo-colonial extractive patterns of excessively large, export-only projects—a risk evident in planned projects. Comprehensive plans for economic development around green H2 production will be crucial to ensure a beneficial industry for decarbonization in Europe and development in Africa alike.

Methods

Sample

We model the LCOH for all African countries with access to ports, excluding landlocked countries, due to the logistical and infrastructural complexities that hinder H_2 export from these areas. Further, Somalia and Libya are excluded from our analysis given that in the past five years, both countries were in the bottom 5% of the World Bank Governance Indicators in terms of political stability[34]. It is therefore likely that investors would refrain from any project in these countries, irrespective of the theoretical COC. Finally, we exclude small island states such as Cape Verde or Mauritius from our analysis due to space and infrastructure constraints. This yields a list of 31 African countries for our sample, which constitute 85% of total African GDP[35].

To collect planned green H_2 projects, we use the IEA Hydrogen Database, which lists 1,991 H_2 projects as of December 2023[20]. Of these, 66 projects are located in our sample countries and plan to produce H_2 from electrolysis using renewable electricity from either wind or solar. We further restrict our sample to projects planned to go online by 2030 for two reasons. First, announced projects with live dates beyond 2030 are likely speculative, and it is difficult to assess the credibility of the plans. Second, the COC and several other cost factors, such as the cost of renewables or the cost of NH_3 shipping are changing over time, making cost projections beyond 2030 difficult.

The final green H_2 project sample consists of 34 projects, for which we include the project's development status, planned first year of operation, designated end-use applications, and size in standardized electrolysis capacity as calculated by the IEA in MW H_2 output (LHV) for all Power-to-X projects (see Supplementary Table 3)[20]. We use the median planned capacity of 60.6 kt/H_2/year as the green H_2 demand for the LCOH modelling.

Estimating the cost of capital

Between February and August 2023, we conducted 12 expert interviews with 13 representatives from both the public and private sectors to inform the financing scenarios shown in Table 1 and to triangulate our assumptions underlying our COC estimations outlined below. These interviews were exploratory and served to understand the planned financing structures of future H_2 deals on the African continent and reasonable assumptions for the calculation of financing scenarios. An overview of the interview sample is provided in Supplementary Table 4.

The COC is the price that a profit-maximizing capital provider demands for investing equity into a project or issuing debt (e.g., loans) for a project. The COC increases with the risk for an investor of being unable to recoup their investment, for example, due to uncertain policy environments or novel risky technologies. In financial economics, it is common practice to decompose the COC into a risk-free rate (reflecting the time value of money) and a risk premium (reflecting the investment-specific risk). The latter typically differs between countries, technologies, and over time[36]. A standard project-level specification of the COC is the weighted average cost of capital (WACC), where capital is sourced from equity and debt financing. The WACC reflects the costs of obtaining debt and equity financing, respectively, and the share of each type within the total capital budget. In line with the literature[36], a standard notation "vanilla-WACC" (no consideration of potential tax deductions for debt payments) can be defined as follows:

$$WACC = \left(\frac{E}{V} \times K_{e,i}\right) + \left(\frac{D}{V} \times K_{d,i}\right) \quad (1)$$

where $K_{e,i}$ and $K_{d,i}$ denote the cost of equity and the cost of debt, respectively, for investments in a specific country i. E, D, and V denote total equity, debt, and capital; the debt share is denoted as $\frac{D}{V}$. As we model the case of exporting green H_2 from Africa to Europe, it is uncertain which entities would be liable to pay tax where and we do not consider a country-specific tax rate. We use the terms COC and WACC interchangeably in this paper, focusing on COC in the main text for simplicity. In the absence of a track record for the financing of green H_2 projects globally and certainly in Africa, we define four financing scenarios to model the COC based on insights from the finance literature and expert interviews (see Table 1, main text).

Across all financing scenarios, we use a separate COC for the plant investment encompassing H_2 production facilities (e.g., the electrolyser), the RE generation assets, and the supporting infrastructure encompassing roads, pipelines, etc. The risk-free rate r_f is based on the 10-year US treasury bond yield[37]. In line with previous work[38], we estimate r_f for a high- and a low-interest rate scenario to account for the fact that the interest rate environment has a large impact on the cost of renewables. We set $r_{f_{low}}$ to 2%, which is reflective of the five-year average of the 10-year treasury bond in the aftermath of the financial crisis of 2008 between 2009 and 2013. Conversely, $r_{f_{high}}$ is set to 5%, which is representative of the high-interest environment at the time of writing in 2023, with the effective FED rate being set to 5.33% in September 2023[24]. The share of debt in total financing, $\frac{D}{V}$, is assumed to be 75% across all scenarios[17].

We model a commercial scenario in both interest rate environments (see Table 1, main text). For these commercial scenarios 1 and 3, we define the cost of debt to reflect lending to a large infrastructure project in a specific country. Namely, we add a country default spread to reflect country risk[39] (CDS_{Host_i}) and a lender margin (L_m), which we set to 2% in line with the literature[14,40,41], to reflect infrastructure risk. The country default spreads are reflective of country risk at the time of writing in 2023. The cost of debt for the plant is therefore given by:

$$K_{d,i,commercial,plant} = r_{f_{low,high}} + CDS_{Host_i} + Tp \tag{2}$$

Similar to the cost of debt, the cost of equity contains a country mark-up. Furthermore, we add an equity risk premium and a technology premium to reflect the additional risk of equity compared to debt and the risk of green H_2 investments, as there is a very limited track record. The cost of equity for commercial scenarios was calculated as follows:

$$K_{e,i,commercial,plant} = r_{f_{low,high}} + ERP + CRP_{Host_i} + Tp \tag{3}$$

where ERP is the equity risk premium of a mature market, set to 5% in July 2023[39]. CRP_{Host_i}varies by country i and accounts for the return that investors require as compensation for the risk of an investment in a publicly listed company in each country. In addition, the technology premium (Tp) reflects that green H_2 is a relatively immature technology with a limited track record of successfully constructing large-scale projects. Following a recent IRENA report[14], Tp is set to 3.25%, reflecting an investment premium for novel technologies. Since ref.[39] does not provide CDS_{Host_i} and CRP_{Host_i} for Eritrea, Equatorial Guinea, Djibouti and Mauritania, CDS_{Host_i} is obtained using Wikiratings as described in Supplementary Table 5. Thereafter, CRP_{Host_i} is calculated following the approach suggested by ref.[39].

Finally, we assume that any supporting infrastructure will be financed by a project's host government at its sovereign rate. Consequently, the COC for infrastructure is given by:

$$COC_{i,commercial,infra} = r_{f_{low,high}} + CDS_{Host} \tag{4}$$

For the de-risked scenarios 2 and 4 (see Table 1, main text), we model a situation where a green H_2 project on the African continent benefits from access to below-market terms financing due to an offtake guarantee from a Western European government entity. This assumption follows developments driven in particular by Germany, which has established diplomatic relations to support the transition of current fossil fuel exporting nations such as Angola or Nigeria to a decarbonized energy export industry by substituting fossil fuel exports at least partially by H_2[42]. Moreover, Germany has recently announced a joint declaration of intent with the Netherlands to implement a joint tender under the H2Global Instrument, offering 10-year purchase agreements to suppliers to kick-start the emergent European green H_2 import market[43]. Finally, Germany has signed further bilateral partnership agreements with countries such as South Africa[44], Namibia[45], and Kenya[46].

In these scenarios, the cost of debt can be represented as follows:

$$K_{d,i,derisked} = r_{f_{low,high}} + CDS_{WesternEU} + MIGA_{expr_i} + MIGA_{war_i} \tag{5}$$

where $CDS_{WesternEU}$ represents the average default spread of a Western European country weighted by its GDP, where Western Europe includes Andorra, Austria, Belgium, Cyprus, Denmark, Finland, France, Germany, Greece, Guernsey, Iceland, Ireland, Isle of Man, Italy, Jersey, Liechtenstein, Luxembourg, Malta, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the UK[39]. In July 2023, this amounted to 0.96%[39]. Despite the off-take guarantee, certain risks, such as the risk of expropriation or war, will remain. Consequently, we assume that in scenarios 2 and 4, investors will seek insurance against such political risks, which could disrupt operations or damage assets. Informed by the expert interviews and because private political risk insurance is not available in most countries in our sample, we assume political risk insurance by the World Bank Group's Multilateral Investment Guarantee Agency (MIGA). $MIGA_{expr_i}$ and $MIGA_{war_i}$ represent the price for obtaining such coverage for war and expropriation risk. As the MIGA pricing is confidential, we develop a heuristic to approximate the pricing based on reports and the expert interviews. Ref.[47] states that the price per MIGA risk ranges from 0.5% to 1.75% of the total sum insured, depending on the country and project risk. Assuming that in a de-risked scenario, only country risk will remain as the project is fully de-risked, the distribution of in-sample country risk, reflected by the credit default spread provided by ref.[39] can be mapped onto the pricing range indicated by ref. . Formally, the approach can be represented as follows:

$$MIGARiskPricing(x) = f(g(x)) \tag{6}$$

Where x is the percentile of the default spread of a country based on ref.[39], $g(x)$ returns the percentile of the CDS in the sample distribution and $f(\,)$ maps the percentile to the corresponding percentile of the MIGA pricing range[47].

The cost of equity was calculated as follows:

$$K_{e,i,derisked,plant} = r_{f_{low,high}} + ERP + CRP_{WesternEU} \tag{7}$$

where $CRP_{WesternEU}$ reflects the average equity country risk premium in Western Europe weighted by GDP. In July 2023, this premium was 1.37%[39].

Finally, we assume that infrastructure in the de-risked scenarios is either financed by the host government, i.e., as in the commercial scenarios or financed by the project sponsor backed with an offtake guarantee from a Western European government. We therefore define the COC for infrastructure investments in the de-risked scenarios as the minimum of the host government's sovereign rate $WACC_{commercial,infra}$ and the de-risked COC based on $K_{e,i,derisked,plant}$ and $K_{d,i,derisked,plant}$. A detailed breakdown of how the COC components were obtained as well as the corresponding data sources is provided in Supplementary Table 5.

Modelling the levelized cost of green hydrogen (LCOH)

The GeoH$_2$ optimization model is used to calculate the lowest possible cost of H_2 achievable throughout each country, assuming an electrolyser lifetime of 20 years. It tessellates the country into hexagons and calculates the costs to (1) produce the specified quantity of green H_2 (or here, green NH_3) in each hexagon, (2) convert it to the required state for transport, and (3) transport it to a specified demand location. In each hexagon, a cost-optimal off-grid H_2 plant powered by PV and wind turbines is designed to meet the specified demand. The electrical infrastructure (i.e., PV, turbines, battery storage) and plant infrastructure (i.e., electrolyser, NH_3 storage, compressed H_2 storage) are sized for cost optimality using site-specific, hourly weather data from the European Centre for Medium-Range Weather Forecasts Reanalysis v5 dataset[48]. Here, data for the duration of 2022 is used. The Corine Land Cover[49] and OpenStreetMap[50] datasets are used to constrain land availability in each hexagon. The costs to transport the H_2 to port are calculated for both road transport (i.e., trucking) and pipeline transport, including construction of necessary infrastructure. Water costs for either desalination or freshwater processing/transit are included as applicable – however, no limit is placed on water consumption to avoid depletion in either case. Cost parameters used in the modelling are available in Supplementary Table 1. Further details on the GeoH$_2$ model implementation are available in the model descriptor[13].

The GeoH$_2$ model is applied to each country in the project sample. A demand of 60.6 kt$_{H2}$/year is simulated at each country's main port. This demand is assumed to be produced in the form of green NH_3 (i.e., 341.4 kt$_{NH3}$/year) due to its cost advantages in shipping, and to be temporally uniform (i.e., evenly spaced truck pick-ups throughout the year or a consistent pipeline flow-rate). Country-specific figures are used for energy prices, heat prices, and interest rates. Level four H3 hexagons[51] are used to define the spatial resolution. Land availability is constrained such that H_2 production and associated generation are not permitted to be built on wetland, built-up areas, water bodies, or within 250 m of coastlines or protected areas. PV is additionally not permitted to be built on agricultural land. While elevation is not considered as an exclusion criteria here due to data constraints, future work may also wish to exclude high elevations or steep slopes. Note that this work leverages a model of the Haber-Bosch process in plant optimisation in place of the standard H_2 production process available in the open-source GeoH_2 model[13].

To account for shipping costs, the sea distance from each of the exporting ports to Rotterdam is first calculated using the ShipTraffic website[52]. Previous work has estimated the cost of shipping NH_3 over a distance of approximately 13,800 km to be €0.39/kg_{H2}[12]. Following ref.[22], shipping cost projections depend approximately linearly on transport distance. Consequently, we scale this estimate linearly to km, resulting in our cost parameter of €0.00003/kg_{NH3}/km, which we multiplied with each of the obtained distances from the African port to Rotterdam. Implementing this approach yields a shipping cost range of €0.09/kg_{H2} (Morocco) – €0.44/kg_{H2} (Mozambique), in line with other estimates in the literature, according to which shipping could add up to €0.46/kg_{H2} by 2030[53].

The interest rates for converting green NH_3 to green H_2 in Rotterdam are obtained by following the same approach as for all other countries described in Methods. Following previous work, heat costs of €0.06/kWh are assumed[12]. Electricity costs are assumed to be €0.1/kWh and are calculated as the combination of the average price of Dutch Power Base futures[54] and the price of a guarantee of origin (GO) for renewable electricity. At the time of writing, Dutch Power Base futures are available until October 2028, and the average price obtained is €0.097/kWh. Based on grey literature[55], an average price of a GO of €0.055/kWh by 2030 is assumed. While Rotterdam serves as our comparison case, the resulting electricity cost is deemed representative of the European Union (EU) as a whole, given that historically, Dutch wholesale electricity prices were strongly correlated with German wholesale electricity prices, and the Dutch wholesale price roughly represents the average wholesale electricity price in Europe[56].

Our modelling excludes two cost components: namely, (1) costs associated with upgrading ports to enable large-scale NH_3 shipments, and (2) costs for last-mile distribution in Europe. Both would require detailed information (i.e., on port design and demand locations respectively), which is beyond the scope of this analysis. Furthermore, our model does not account for potential cost reductions in onshore wind, solar PV, electrolysers, and battery storage that may occur by the year 2030. Such cost decreases will not only reduce the cost of green H_2 projects in Africa but may also influence renewable deployment in Europe and, therefore, European wholesale electricity prices. As such, the net effect on the cost competitiveness of African green H_2 exports vs. European green H_2 production remains inconclusive.

Finally, we calculate the LCOH in Rotterdam to create a European cost benchmark. We use the same assumptions for electricity and heat costs as mentioned above to model LCOH for green H_2 produced in Rotterdam using grid electricity due to space constraints for RE. Due to the absence of RE investments, these projects are much less capital-intensive, and variations in the COC, therefore, are less important for LCOH. We calculate an LCOH for production in Rotterdam for each financing scenario shown in Table 1 and obtain an LCOH of €4.65/kg_{H2} for scenario 1, €4.64/kg_{H2} for scenario 2, €4.62/kg_{H2} for scenario 3, and €4.64/kg_{H2} for scenario 4. Because large green H2 production plants do not currently exist, cost estimates are not commonly available, but several reports have tried to estimate costs. These are broadly in line with our costs; for example, Aurora Energy Research estimates the least-cost LCOH in Germany by 2030 between €3.9 and €5/kg_{H2}[57]. Other research reports even lower 2030 costs for Germany of $3.1/$kg_{H2}$ in a baseline scenario and $2.7/$kg_{H2}$ in an optimistic scenario[58], which is roughly the range where the IEA Global Hydrogen Review places North-Western European green H2 costs by 2020 (€3.1/kg_{H2})[1]. Other European locations, such as Spain, with more favourable RE sources and similarly favourable financing costs, may reach even lower costs by 2030 at €2.7/kg_{H2} as estimated by the Hydrogen Council & McKinsey[59].

Data and code availability

The GeoH2 model is available on Github with a CC-BY-4.0 license: https://github.com/ClimateCompatibleGrowth/GeoH2. Note that the open-source version of GeoH2 models production of H_2, not NH_3, as this leverages a proprietary module housed at the University of Oxford. Technoeconomic modelling data and assumptions are included and referenced in the Supplementary materials. The full numeric results of the modelling can be made available upon request.

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Author contributions

F.E. and S.H. conceived the research idea. F.E., F.S., S.H. and T.S.S. designed the research plan. F.S. collected the COC data and developed the scenarios and calculations with F.E. A.L. and C.H. curated the data for GeoH2, ran the model and plotted the results. N.S. contributed the NH3 module. F.E. wrote the original draft with input from F.S. F.S., A.L., S.H., C.H., T.S.S. and N.S. reviewed and edited subsequent drafts. F.E. and S.H. supervised the research, S.H. acquired funding for Oxford.

Competing interests

The authors declare no competing interests.