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Hydrogen supply chains across Chinese provinces for production and transportation

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Decarbonization involves the wide use of hydrogen for mitigating emissions from hard-to-abate sectors, thus credible economic assessment of its various production and transportation modes is essential. We develop a spatially explicit analytical framework that integrates supply-chain levelized cost of hydrogen analysis with an optimal transportation network. The network optimization model embeds a distance-throughput curve and applies a dual feasibility rule requiring that any candidate transport connection meets both the minimum throughput requirement and cost-effectiveness. Here we show that storage and transportation account for about 20-50% of delivery costs of hydrogen across Chinese provinces. A large-scale pure-hydrogen pipeline network of approximately 59,000 kilometers is projected by 2060 across the scenarios, and the interprovincial hydrogen flows are concentrated along a few corridors linking inland producers to eastern and southeastern demand centers. This study provides a comprehensive assessment of hydrogen economics in China, including supply-chain analysis and infrastructure planning, offering policymakers scientifically supported strategies for energy transition.

The growing urgency of mitigating climate change has elevated deep decarbonization to a central objective of global energy transitions[1]. In this context, hydrogen has emerged as a key energy carrier and plays a critical role[2], particularly in hard-to-abate sectors such as industry (e.g., steel, chemicals, and cement) and transportation (e.g., long-haul trucking, shipping, and aviation)[3–7]. According to the International Energy Agency (IEA), global hydrogen consumption is estimated to surpass 100 million tons (Mt) by 2025, while demand for low-emission hydrogen grew by about 10% in 2024[8]. Cumulative CO_2 reductions by 2050 could reach ~80,000 Mt, an amount equivalent to about 11% of the total mitigation required to keep temperature increases within the 1.5–1.8 °C threshold[9]. Therefore, hydrogen has been considered an indispensable part of global decarbonization strategies[10].

China's rapidly expanding role in the global hydrogen landscape contrasts with the pronounced structural limitations of its domestic hydrogen storage and transportation (S&T) system. Although China has become the world's largest market for electrolyzer deployment and has achieved installation costs well below those in many other regions[11], it still lacks a dedicated hydrogen pipeline network of sufficient scale. China's hydrogen pipeline infrastructure remains at an early stage of development. This pattern is not unique to China. In the United States, existing hydrogen pipelines remain limited (~1600 miles) and are primarily concentrated in industrial clusters[12]. In Europe, hydrogen pipeline systems remain fragmented, with large-scale backbone networks still largely in the planning stage[13]. However, in China, these infrastructure constraints translate into more pronounced system-level consequences. Substantial spatial mismatches emerge between renewable-rich inland provinces, where low-cost green hydrogen can be produced, and coastal industrial demand centers. In the absence of a well-developed pipeline backbone, long-distance hydrogen delivery currently relies predominantly on trucking, which significantly increases delivered levelized cost of hydrogen (LCOH), widens regional cost disparities, and restricts the integration of variable renewable energy into hydrogen production. These frictions suggest that national-level averages mask sharp provincial cost heterogeneity and may lead to inefficient infrastructure planning if regional characteristics are not explicitly considered. These challenges highlight the need for a spatially explicit assessment of China's hydrogen production and S&T system that can reflect provincial-level variations in resource endowments, industrial demand, and S&T cost structures.

Recent policy developments in China have begun to accelerate the deployment of hydrogen S&T infrastructure[14]. National strategies and pilot policies have explicitly promoted the development of hydrogen pipeline systems, including long-distance transmission pilots and demonstration projects integrating hydrogen production, storage, transportation, and end-

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use[15]. For example, recent Inner Mongolia plans propose a phased development pathway from pilot projects to backbone pipeline networks, with structured layouts (e.g., trunk lines and regional corridors) designed to connect renewable-rich production bases with major demand centers[16]. In Europe, Germany plans to build a 9700-kilometer dedicated hydrogen pipeline network by 2032[17], reflecting a strategy that emphasizes cross-border backbone networks and large-scale infrastructure integration at the continental level. In the United States, federal programs emphasize the role of pipeline infrastructure in connecting hydrogen production and demand centers[18]. Together, these global policy developments suggest that large-scale hydrogen pipeline deployment is becoming a central component of national decarbonization strategies. They further underscore the growing importance of hydrogen S&T infrastructure and highlight the need for analytical frameworks that can systematically assess S&T costs and inter-regional hydrogen flows under future large-scale deployment scenarios.

Despite the growing importance of midstream S&T, existing studies have primarily focused on upstream hydrogen production across grey, blue, and green routes. These differences directly translate into variations in LCOH, which fundamentally determine hydrogen economics. For grey hydrogen, its apparent cost advantage diminishes with increasing carbon prices[19,20], while the competitiveness of blue hydrogen depends on CO_2 capture rates as well as S&T costs[21–23]. For green hydrogen, numerous studies highlight its strong sensitivity to electricity prices, renewable resource quality, and electrolyzer technology learning effects[24–27]. Evidence further shows that regional variations in renewable resources, industrial structure, and electricity market conditions lead to substantial spatial heterogeneity in green hydrogen production costs[28–30]. However, most existing analyses evaluate hydrogen production on a plant-gate basis, treating production costs largely in isolation from midstream S&T. As a result, they often overlook spatial mismatches between resource-rich production sites and distant demand centers, potentially overstating the economic competitiveness of green hydrogen in regions lacking adequate transport infrastructure or facing long delivery distances. Collectively, this body of work provides important insights into how production technologies[31], energy-price dynamics[32], and regional resource conditions[33] influence LCOH, but offers limited understanding of full-chain hydrogen economics.

Existing studies on hydrogen S&T remain comparatively fragmented and can be broadly categorized into three strands. One strand of research focuses on the techno-economic characteristics of individual transportation modes, including gaseous and liquid hydrogen[34], as well as hydrogen carriers such as ammonia and liquid organic hydrogen carriers (LOHCs)[35]. A second strand of studies investigates optimal transmission options for long-distance scenarios, comparing hydrogen pipelines, natural gas pipelines, and electricity transmission via ultra-high-voltage (UHV) networks[36,37]. While these studies provide valuable insights into mode selection and cost thresholds, they generally treat transportation modes as exogenous and do not characterize the endogenous formation of interregional hydrogen flows and network structures. A third strand adopts an engineering-oriented perspective, focusing on the technical feasibility, safety constraints, and cost components of hydrogen pipeline systems, thereby offering detailed insights into pipeline design and operation[34,38]. However, these analyses rarely incorporate system-level optimization or spatial network formation. As a result, most existing studies consider transport options in isolation, rather than within an integrated upstream-midstream framework.

Based on the limitations identified above, three key research gaps hinder a comprehensive full-chain assessment of hydrogen economy. First, most existing studies do not integrate full-chain hydrogen economics, as production, and S&T are typically analyzed in isolation, limiting understanding of their joint techno-economic effects[39]. Second, limited attention has been paid to infrastructure threshold relationships, such as distance-throughput, and provincial heterogeneity is not consistently incorporated into modeling frameworks[40,41]. Current assessments provide limited insights into how pipeline length, flow volume, and regional diversity jointly shape spatial cost patterns or influence the long-term deployment of hydrogen S&T infrastructure[42]. Third, most studies lack multi-provincial modeling frameworks that account for interprovincial supply-demand mismatches and network interactions[43–45]. Existing analyses do not explicitly represent the coupling between upstream production patterns and midstream S&T routes and flow allocation across Chinese provinces, limiting the assessment of spatial network effects on regional competitiveness and long-term deployment. Therefore, effective hydrogen deployment strategies require an integrated and spatially explicit analytical framework that jointly incorporates full-chain hydrogen costs and S&T infrastructure requirements, enabling regional investment prioritization and important infrastructure system planning.

To address these research gaps, we develop a spatially explicit provincial-level framework for China that unifies full-chain LCOH with network optimization, explicitly addressing these gaps through integrated cost modeling, endogenous S&T mode competition, and interprovincial network formation. The analysis framework integrates upstream production routes, midstream S&T, and downstream demand projections across 31 provinces in China. We parameterize a distance-throughput and a complementary rule that requires the simultaneous satisfaction of volumetric and economic conditions, endogenize competition among various hydrogen transport modes, and generate cost-minimizing interprovincial pure-hydrogen pipeline networks for a 2020 reference scenario and for 2060 carbon-neutrality scenarios.

Our results reveal several important findings. Midstream S&T accounts for a substantial share of hydrogen delivery costs, typically representing 20–50% of the total delivered cost across Chinese provinces, and is the primary driver of cost difference among provinces. Economically feasible pure-hydrogen pipelines concentrate along a small number of west-to-east and north-to-southeast corridors, with the cost-optimal network reaching ~59,000 kilometers in 2060. In 2060, 25 province-pair connections meet the joint distance-throughput threshold for pipeline viability across all scenarios. Under 2060 scenarios, network configuration is primarily characterized by capacity scaling of existing corridors rather than the construction of entirely new pipelines. Our analysis identifies and prioritizes regions, quantifies policy-relevant thresholds, and provides systematic sensitivity insights suitable for hydrogen transportation network planning.

Results

Current supply-chain LCOH of grey and blue hydrogen across provinces

We analyze the provincial-level LCOH patterns of grey and blue hydrogen in Fig. 1. Fossil-based routes include hydrogen produced from coal, natural gas, and industrial by-product, as well as blue hydrogen derived from these processes with carbon capture, utilization, and storage (CCUS) systems. Fossil-based routes dominate China's current hydrogen supply, accounting for around 99% of total hydrogen production. Among fossil-based routes, coal-derived hydrogen is the lowest-cost option, followed by industrial by-product hydrogen and natural-gas-based hydrogen, while blue hydrogen remains the most expensive among the assessed fossil-based routes due to the additional CO_2 capture requirement.

At the regional scale, inland energy-producing provinces generally exhibit lower costs, while coastal importing provinces face noticeably higher values, reflecting the influence of resource endowments, feedstock prices, and existing industrial structures on hydrogen production costs in China. Coal-based hydrogen shows the lowest cost, with its production LCOH ranging from about 2.00 to 2.87 USD/kg H_2. Natural-gas-based hydrogen ranges from 2.82 to 4.11 USD/kg H_2, with Xinjiang showing the lowest cost (2.82 USD/kg H_2) due to favorable gas prices and proximity to major natural gas supply sources. Hydrogen from industrial by-product varies between 1.35 and 3.22 USD/kg H_2, largely reflecting differences in the scale of heavy industry. Blue hydrogen displays the widest provincial cost variation, ranging from 2.81 to 5.23 USD/kg H_2. In contrast, regions lacking CCUS infrastructure face substantially higher costs.

After incorporating midstream S&T costs, the supply-chain LCOH of fossil-based hydrogen rises substantially, and the spatial cost pattern shifts across provinces. In this study, S&T includes three modes: gaseous hydrogen trucking, liquid hydrogen trucking, and gaseous hydrogen pipeline transportation. Midstream S&T costs are computed using distance-dependent

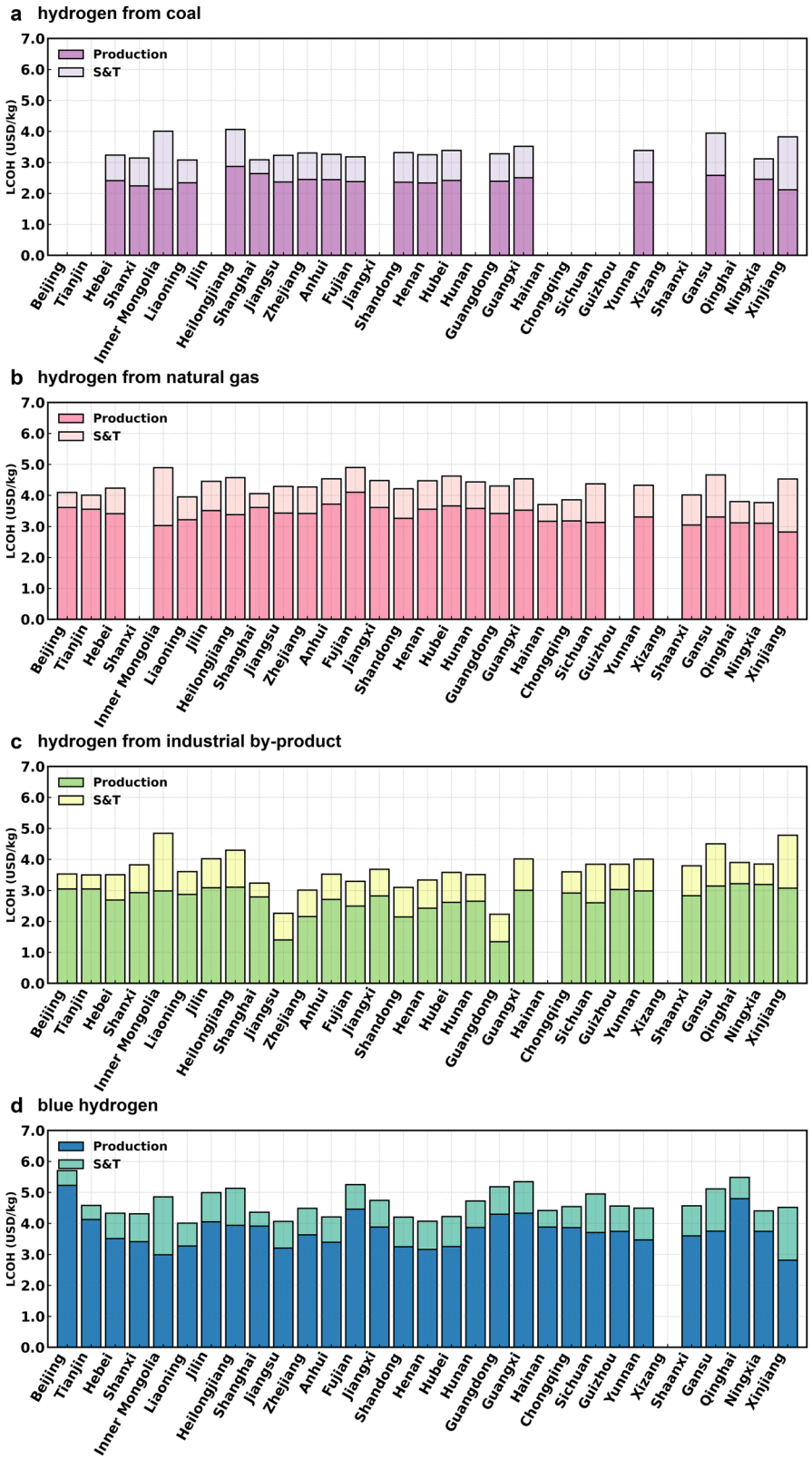

Fig. 1 | Supply-chain LCOH of grey and blue hydrogen across Chinese provinces under model-based 2020 reference. This figure presents the variation of supply-chain LCOH (in USD/kg H_2) across 31 Chinese provinces for gray and blue hydrogen. The bar chart consists of two parts: the lower part represents the unit cost of upstream hydrogen production, and the upper part represents the unit cost of midstream hydrogen S&T. **a** Hydrogen from coal. **b** Hydrogen from natural gas. **c** Hydrogen from industrial by-product. **d** Blue hydrogen, meaning fossil-based hydrogen with CCUS.

and throughput-dependent cost functions for each transport mode, integrated within the provincial network-optimization model. For coal-based hydrogen, natural-gas-based hydrogen, hydrogen from industrial by-product, and blue hydrogen, S&T costs account for 38–47% of total supply-chain costs, highlighting their pivotal role in determining provincial competitiveness.

Current supply-chain LCOH of green hydrogen across provinces

We assess the provincial-level LCOH patterns of green hydrogen in Fig. 2. Green hydrogen refers to hydrogen produced from water electrolysis powered entirely by renewable electricity from wind or solar sources. Four renewable electrolysis routes are covered: wind-based alkaline electrolysis (wind AE), wind-based proton exchange membrane electrolysis (wind

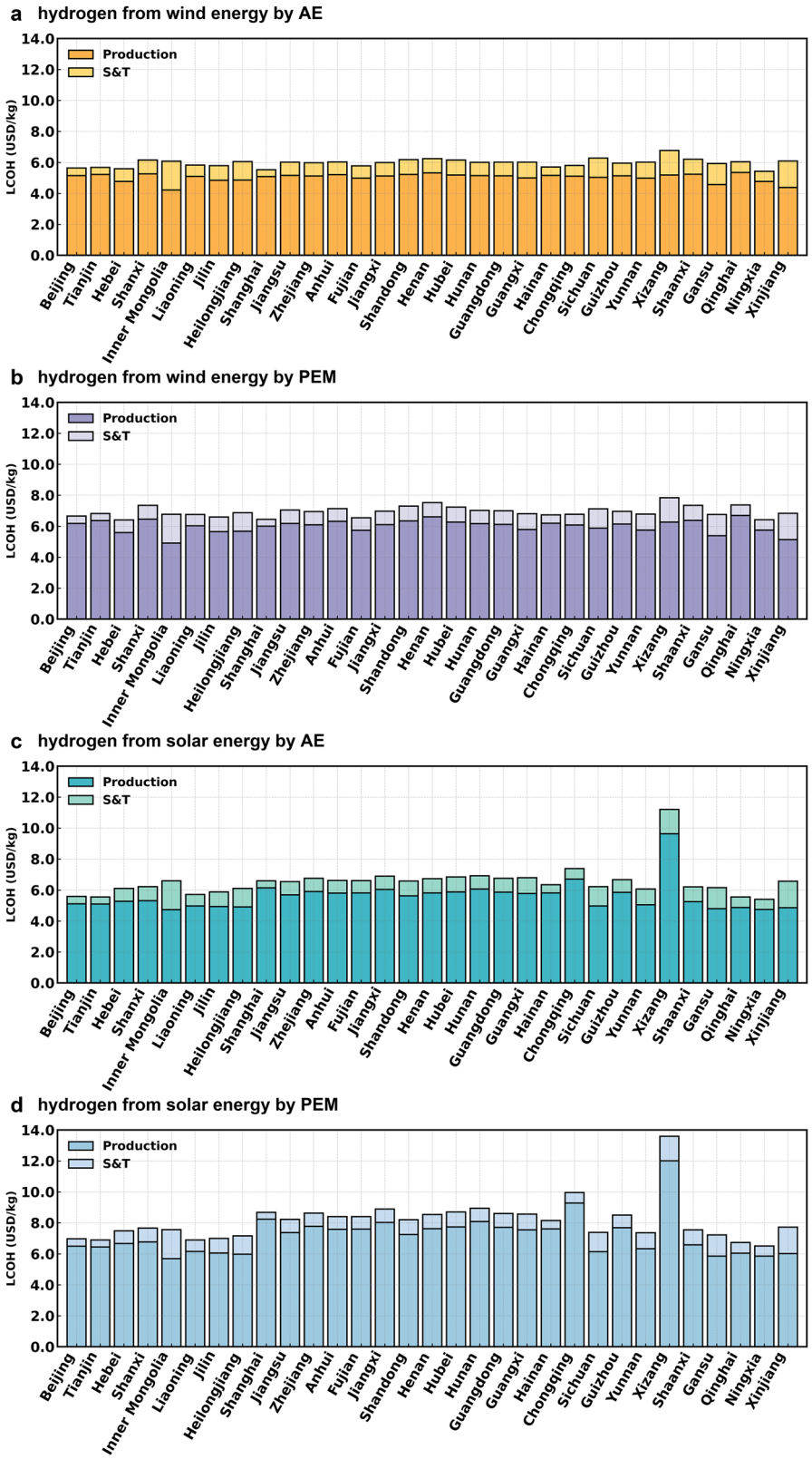

Fig. 2 | Supply-chain LCOH of green hydrogen across Chinese provinces under model-based 2020 reference. This figure presents the variation of supply-chain LCOH (in USD/kg H_2) across 31 Chinese provinces for green hydrogen production technologies. The bar chart consists of two parts: the lower part represents the unit cost of upstream hydrogen production, and the upper part represents the unit cost of midstream hydrogen S&T. **a** Hydrogen from wind energy by AE. **b** Hydrogen from wind energy by PEM. **c** Hydrogen from solar energy by AE. **d** Hydrogen from solar energy by PEM. AE and PEM denote alkaline electrolysis and proton exchange membrane electrolysis, respectively.

PEM), solar-based alkaline electrolysis (solar AE), and solar-based proton exchange membrane electrolysis (solar PEM).

Our assessment finds that wind-powered electrolysis, particularly wind AE, forms the lowest-cost green hydrogen option in China, followed by wind PEM, while hydrogen produced from both solar AE and solar PEM remains significantly more expensive due to higher electricity tariffs and lower capacity factors. The cost dispersion of green hydrogen is generally wider than that of grey and blue hydrogen, primarily due to variations in renewable electricity prices, renewable resource quality, and electrolyzer performance. These differences underscore the dominant role of renewable resource quality and local power tariffs in shaping provincial green hydrogen costs.

The provincial production LCOH results reveal a clear hierarchy across green hydrogen production routes and regions. Provincial production

LCOH values range from ~4.22 to over 12.02 USD/kg H_2, green hydrogen costs are on average 74.2% higher than those of grey and blue hydrogen. These patterns indicate that upstream green hydrogen production economics are primarily shaped by renewable resource quality, renewable electricity prices, and electrolyzer technical-economic parameters, with PEM and solar-based routes remaining economically unfavorable under current conditions.

Once midstream S&T costs are included, the supply-chain LCOH for green hydrogen increases markedly across all four renewable routes. Midstream S&T costs constitute a notable portion of supply-chain LCOH for all renewable pathways, 30.6% for wind AE, 27.5% for wind PEM, 28.3% for solar AE, and 24.7% for solar PEM, highlighting the pivotal role of S&T in shaping provincial green hydrogen economics. The S&T component varies widely, ranging from 0.45 to 1.87 USD/kg H_2, with inland provinces generally showing higher values than coastal regions. Spatial dispersion and long-distance transport inflate S&T costs in inland provinces, offsetting their production-cost advantages, while concentrated demand and short transport distances limit S&T additions in coastal regions.

Supply-chain LCOH of green hydrogen under carbon neutrality scenarios in 2060

To examine green hydrogen supply costs under long-term decarbonization scenarios, we estimate provincial-level supply-chain LCOH in 2060 under three demand pathways: low, moderate, and high. Differences across the three pathways are implemented by varying demand (Fig. 3), while other inputs (for example, renewable electricity prices and S&T unit cost parameters) are held consistent. In all scenarios, hydrogen supply is assumed to be fully met by wind- and solar-based electrolyzers. The framework computes provincial supply-chain LCOH by jointly considering local production and interprovincial imports under the modeled least-cost supply mix, allowing us to quantify how cost convergence, import dependence, and spatial heterogeneity evolve by 2060.

The national demand of hydrogen for 2060 is sourced from the International Institute for Applied Systems Analysis (IIASA) Chinese Model Intercomparison (CMIN) database, which provides projections of hydrogen from several Integrated Assessment Models (IAMs) under China's carbon-neutrality pathways[46]. Based on these IAM results, we select three trajectories of hydrogen deployment under China's carbon neutrality target with 55 Mt/yr (low demand scenario), 109 Mt/yr (moderate demand scenario), and 187 Mt/yr (high demand scenario) of hydrogen demand in 2060, respectively representing the lower-, medium-, and upper-bound future hydrogen deployment in China.

The results indicate relatively low supply-chain LCOH levels across importing provinces under the 2060 carbon-neutrality scenarios. All scenarios show clear movement toward cost convergence between producing regions in the northwest and major demand centers along the eastern coast. In the low demand scenario, cost differences remain noticeable, and several coastal provinces still face a premium for external supply. Under the moderate demand scenario, provincial supply-chain LCOH values converge more substantially as upstream costs decline with faster learning. In the high demand scenario, more rapid upstream cost reductions further narrow interprovincial disparities, resulting in a nearly integrated cost landscape in which most provinces approach similar supply-chain LCOH levels. Overall, the 2060 projections highlight the role of upstream technology progress in reducing spatial cost disparities and improving cost competitiveness in China.

The prior analysis emphasizes demand-side variation, the following results examine how technological learning in electrolyzers reshapes provincial supply-chain LCOH patterns by 2060. We estimate provincial-level supply-chain LCOH in 2060 under three electrolyzer learning scenarios: slow, moderate, and fast (Fig. 4). In these scenarios, the reduction in supply-chain LCOH primarily stems from assumed electrolyzer learning effects in upstream production. The spatial evolution of supply-chain LCOH differs markedly across the three learning-driven pathways. Under the slow learning scenario, provincial costs remain relatively dispersed (4.69–6.24 USD/kg H_2), and many coastal importing provinces, such as Jiangsu, Zhejiang, Guangdong, and Fujian, continue to face a clear cost disadvantage associated with reliance on external supply. Under the moderate learning scenario, cost differences narrow significantly (4.47–6.08 USD/kg H_2) as upstream costs decline with faster learning, reducing the gap between inland production bases and coastal demand centers. Under the fast learning scenario, more rapid upstream cost reductions further narrow interprovincial disparities (4.36–6.00 USD/kg H_2), producing an integrated spatial pattern. Under this scenario, major coastal demand centers exhibit a more import-oriented supply mix, reflecting the growing cost advantage of large renewable hydrogen bases. Provinces such as Shaanxi, Yunnan, and Shandong show substantial external inflows, indicating the cost advantage of large renewable hydrogen bases. Nonetheless, a few geographically remote or infrastructure-constrained provinces, such as Xizang and Xinjiang, continue to exhibit relatively high supply-chain LCOH due to long transport distances and dispersed demand.

Hydrogen pipeline network analysis

Hydrogen pipeline transportation is a crucial enabler of large-scale interprovincial hydrogen trade, connecting inland resource bases with coastal demand centers. It plays a crucial role in balancing regional production and consumption disparities and improving the overall efficiency of China's hydrogen supply network.

To identify where pure hydrogen pipelines are economically feasible under the 2020 reference scenario, we construct a transportation-optimization model that allocates interprovincial hydrogen flows to minimize delivered costs (Fig. 5). For each province, the model first determines whether local supply exceeds or falls short of local demand and then evaluates all possible inflow and outflow transport routes. Pipeline transportation is selected only when its delivered cost is lower than trucking for the same origin-destination pair, based on the distance-throughput condition defined in the Methods section.

The optimized pipeline network under the 2020 reference scenario reveals that only a limited subset of interprovincial links satisfies the economic feasibility conditions for pure hydrogen pipeline deployment. The resulting flows are highly concentrated along a limited number of long-distance corridors connecting resource-rich inland provinces with major coastal demand centers. Xinjiang and Inner Mongolia emerge as the dominant exporting hubs, while coastal and central provinces such as Jiangsu, Zhejiang, Guangdong, Shandong, and the Beijing-Tianjin-Hebei region act as the primary demand centers. Most provinces do not meet the distance-throughput threshold required for constructing pipelines and therefore rely economically on trucking. According to the principle of minimizing costs, the needed length of the pure hydrogen pipeline network is estimated at ~39,400 kilometers under the 2020 reference scenario, reflecting the network scale of infrastructure needed if interprovincial hydrogen flows were organized purely based on cost-optimal allocation. Overall, the model-based 2020 reference network displays a clear west-to-east and north-to-coastal structure, with a few trunk lines carrying the majority of interprovincial hydrogen flows. This configuration underscores the early-stage, highly selective nature of economically viable hydrogen pipeline development given current demand patterns and infrastructure availability.

To better understand the emergence of these long-distance corridors in shaping the cost and network structure, we further examine the characteristics of interprovincial transport distances. The flow-weighted average transport distance is estimated to be ~1773 kilometers under the 2020 reference scenario, indicating the prominence of long-distance hydrogen delivery in cost-optimal network formation. In addition, a significant share of economically viable pipeline routes corresponds to long-distance corridors linking inland production regions to coastal demand centers. These results confirm that transport distance is a key determinant of both S&T costs and the emergence of trunk pipeline structures.

To explore how China's hydrogen pipeline network will possibly develop towards 2060 carbon-neutrality, we extend the transportation-

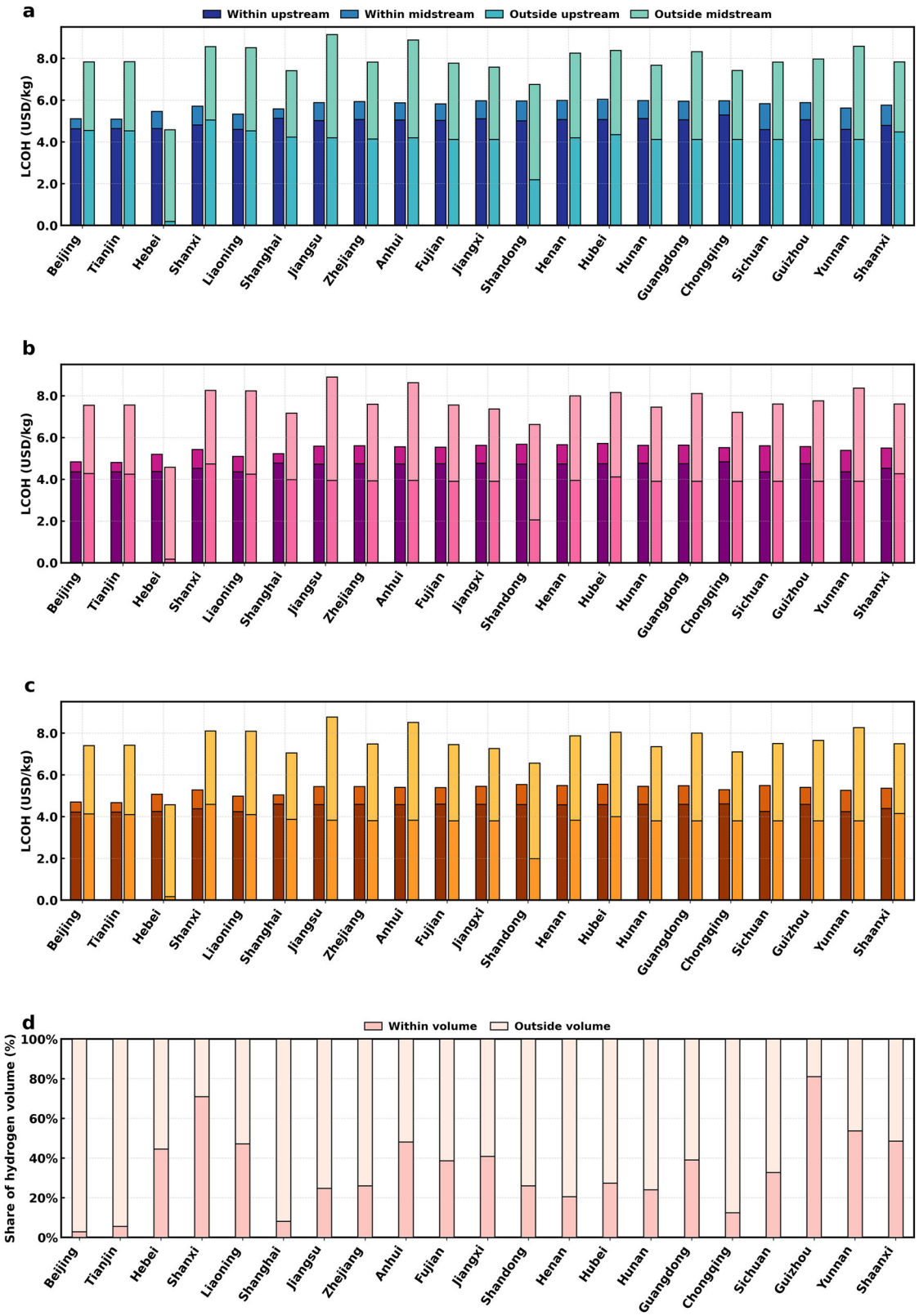

Fig. 3 | Supply-chain LCOH of green hydrogen and hydrogen supply structure under carbon neutrality scenarios in 2060. Panels **a–c** show the decomposition of LCOH under three demand scenarios across importing provinces: **a** low demand scenario, **b** moderate demand scenario, **c** high demand scenario. The supply-chain LCOH is calculated as a technology-mix-weighted value that integrates upstream production costs and midstream S&T costs based on the supply shares of each hydrogen pathway. The four cost components represent upstream production within the province, midstream S&T within the province, upstream production outside the province, and midstream S&T for interprovincial delivery. Panel **d** shows the share of hydrogen produced within provinces compared with that imported from other provinces. For each importing province, the external supply value reflects the minimum delivered cost across out-of-province sources.

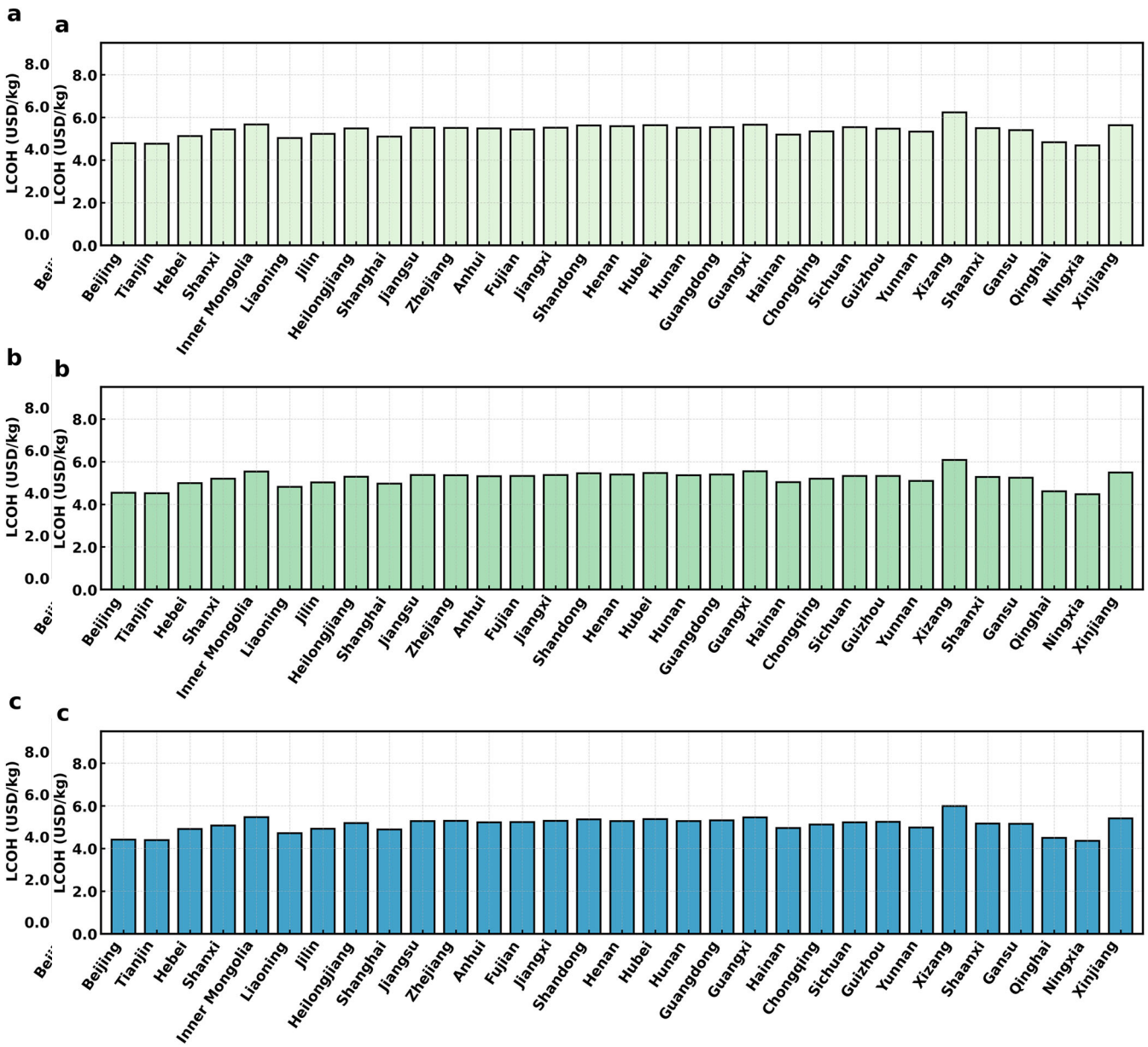

Fig. 4 | Supply-chain LCOH of green hydrogen under different learning scenarios in 2060. This figure compares the provincial supply-chain green LCOH across 31 provincial-level regions in China under three electrolyzer cost-learning scenarios in 2060. For each province, the bar height reports the minimum supply-chain LCOH (in USD/kg H_2) among the four green hydrogen production pathways. **a** slow learning scenario, **b** moderate learning scenario, and **c** fast learning scenario.

optimization framework under the reference scenario to three future demand scenarios (Fig. 6). To ensure consistency with the long-term supply-demand conditions, the 2060 pipeline simulations incorporate both the CMIN-based Chinese demand trajectories and the spatial reallocation of least-cost green-hydrogen production revealed by the supply-chain LCOH analysis. Based on these, we select three demand scenarios: low demand scenario, moderate demand scenario, and high demand scenario of hydrogen in 2060. By 2060, China's hydrogen pipeline system carries much larger volumes over longer distances, while the main west-to-east and north-to-southeast corridors remain broadly similar to those currently. This shift toward longer-distance transmission arises from two structural drivers: first, most incremental green-hydrogen production in 2060 concentrates in the resource-rich northwest, while demand grows predominantly in coastal industrial centers; second, large long-distance trunk pipelines benefit from strong economies of scale, causing a greater share of national hydrogen flows to be routed through a small number of high-volume corridors.

Under the 2060 carbon-neutrality scenarios, aggregate pipeline throughput reaches 30 Mt/yr, 60 Mt/yr and 103 Mt/yr under the low, moderate, and high demand scenarios, respectively. The economically optimal total pipeline mileage is estimated at ~59,000 kilometers. The average transport distance weighted by hydrogen flow reaches about 2522 kilometers, indicating that long-distance hydrogen delivery becomes a dominant feature of the optimized network. The longer transport distances reflect the growing reliance on long-distance hydrogen transmission from resource-rich inland regions to major coastal demand centers, and directly contribute to the observed increase in S&T costs. These two metrics jointly reflect a structural shift toward long-distance delivery, driven by the continued concentration of low-cost renewable hydrogen production in inland provinces such as Xinjiang and Inner Mongolia and the persistent growth of demand in coastal industrial centers. An important observation from the 2060 simulations is that the set of province pairs for which pipeline transportation is economically viable remains unchanged at 25 across all three scenarios.

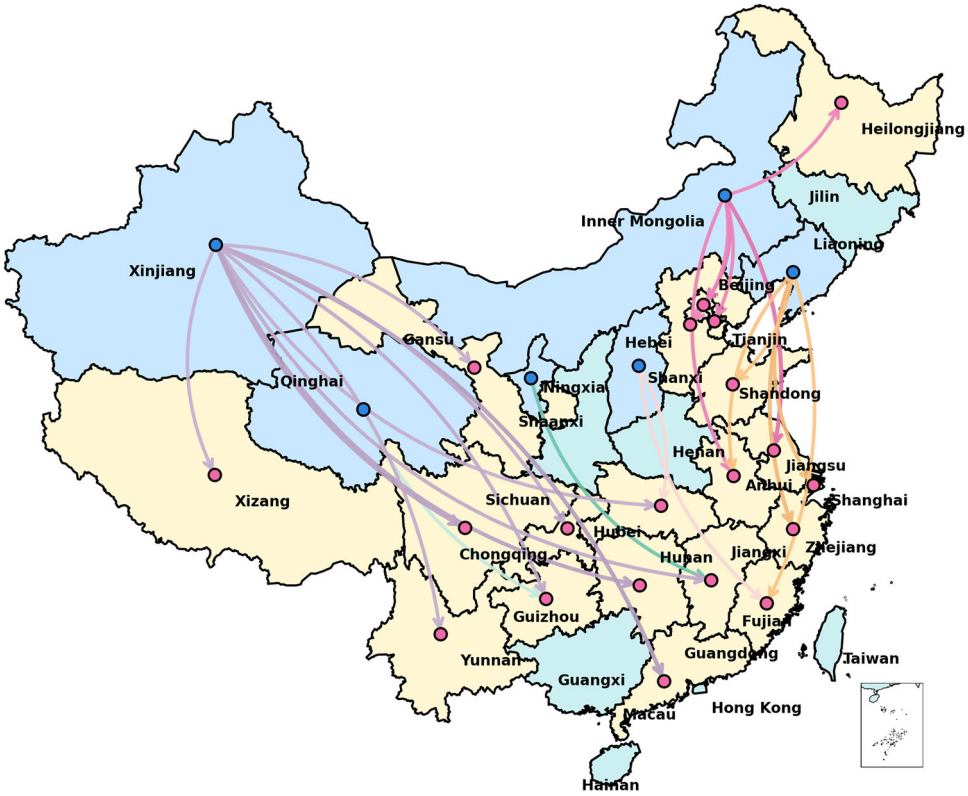

Fig. 5 | Hydrogen transportation pipelines in China under model-based 2020 reference. This figure shows the deployment of pure hydrogen pipeline transportation based on the principle of minimizing costs. The curved arrow represents a pipeline that conforms to the principle, pointing from the exporting province to the importing province. The transportation unit is tons/yr. The thicker the curved arrow, the more hydrogen gas is transported. Blue indicates the exporting province, and yellow indicates the importing province. Blue-green colored provinces are those for which no cost-minimizing external pipeline route is selected under the optimized allocation. However, it does not imply the absence of hydrogen trade in reality, but only that such trade does not occur through the least-cost pipeline routes depicted in the figure.

Pipeline transportation becomes cost-competitive only when both transport distance and flow volume exceed certain thresholds, which explains why only a limited number of long-distance corridors emerge in the optimized network. A pipeline-viable route is one in which the expected annual throughput and transport distance jointly make pipeline delivery less costly than trucking. The stability of this number indicates that expanding hydrogen demand is met primarily by scaling up the capacity of existing trunk backbones rather than by adding new interprovincial links for which pipelines become cost-competitive with trucking. As a consequence, the overall network topology remains stable through 2060, while only the capacities along major corridors scale upward to accommodate larger hydrogen flows.

The results suggest that China's hydrogen pipeline development should follow a staged and coordinated construction approach. In the early phase, when only a limited set of province pairs meets the economic threshold for pipeline deployment, national planning should prioritize a small number of high-volume west-to-east and north-to-southeast hydrogen pipelines. These routes require supporting policies that promote joint provincial planning, synchronized siting of green hydrogen bases, and the co-deployment of storage facilities and industrial hydrogen hubs. As hydrogen supply and long-distance flows expand, the model indicates that increasing the capacity of existing backbone corridors delivers greater economic benefits, while expansion of the network's geographic footprint becomes economically justified only where future demand or industrial relocation significantly alters the pipeline-trucking threshold. To support a resilient and efficient national policy system, policies should focus on standardizing pipeline design and safety codes, establishing transparent tariff and open-access rules, improving cross-provincial coordination mechanisms, and developing financing frameworks that reduce the cost of capital for long-distance trunk lines. Strengthening these institutional foundations is essential for enabling hydrogen pipelines to expand with rising demand and to support the formation of a reliable, integrated, and cost-effective national hydrogen economy.

Current supply-chain LCOH of importing provinces

To evaluate the delivered cost of hydrogen for provinces that rely partly on interprovincial supply, we combine provincial-level upstream production costs, midstream S&T costs, and calculated interprovincial delivery flows to estimate the minimum supply-chain LCOH for each importing province under the 2020 reference scenario (Fig. 7). For each net-importing province, the framework compares the cost of local hydrogen production with the delivered cost of potential external sources, selecting the least-cost external pathway. This allows us to identify which provinces face a cost addition when importing hydrogen and how production and S&T components jointly shape the cost viability of external supply.

The results reveal that most net-importing provinces face noticeably higher supply-chain LCOH from external sources than from within-province production. Among the 23 net-importing provinces, 22 exhibit higher external LCOH, while Xizang is the only province where imports are cheaper than local supply. The median external-internal LCOH gap is 2.23 USD/kg H_2 (interquartile range 1.35–3.16 USD/kg H_2), indicating that interprovincial supply generally imposes a significant cost addition under the modeled infrastructure configuration. Provinces with the largest external cost premiums include Guangdong (+5.28 USD/kg H_2), Hunan (+3.98 USD/kg H_2), Jiangxi (+3.56 USD/kg H_2), Yunnan (+3.46 USD/kg H_2), and Jiangsu (+3.43 USD/kg H_2). These results suggest that hydrogen imports are economically unfavorable for most provinces, primarily due to high external S&T costs.

Cost decomposition reveals that the external production component is often slightly lower than local upstream production, with a median difference of –0.37 USD/kg H_2, reflecting lower production costs in resource-rich exporting provinces such as Inner Mongolia and Xinjiang. However, this production advantage is more than offset by much higher external S&T costs, which exceed internal S&T costs by a median of +2.52 USD/kg H_2 (mean value + 2.69 USD/kg H_2). These elevated external S&T costs arise from long interprovincial transmission distances, limited corridor coverage, and low throughput of early-stage

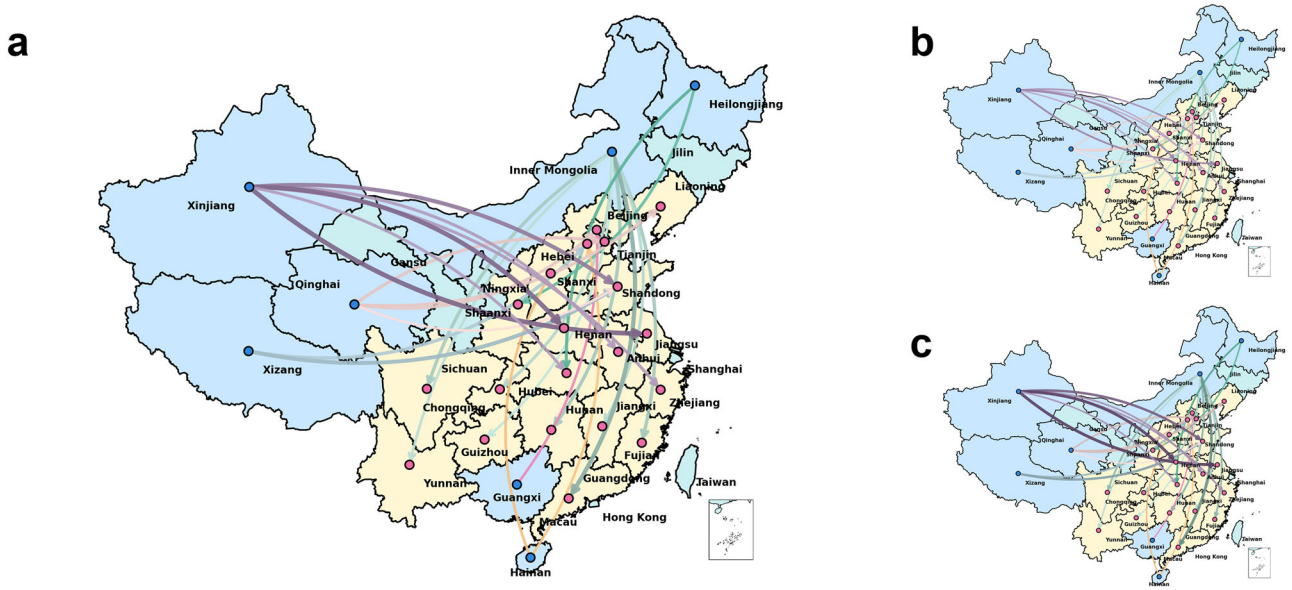

Fig. 6 | Hydrogen transportation pipelines in China under 2060 carbon-neutrality scenarios. This figure illustrates the projected interprovincial hydrogen pipeline flows in 2060 under the carbon-neutrality scenarios with three levels of demand: **a** low demand scenario, **b** moderate demand scenario, and **c** high demand scenario. The visualization adopts the same symbolic definitions as Fig. 5. Besides, blue-green provinces are those for which no cost-minimizing external pipeline route is selected under the optimized allocation. However, it does not imply the absence of hydrogen trade in reality, but only that such trade does not occur through the least-cost pipeline routes depicted in the figure.

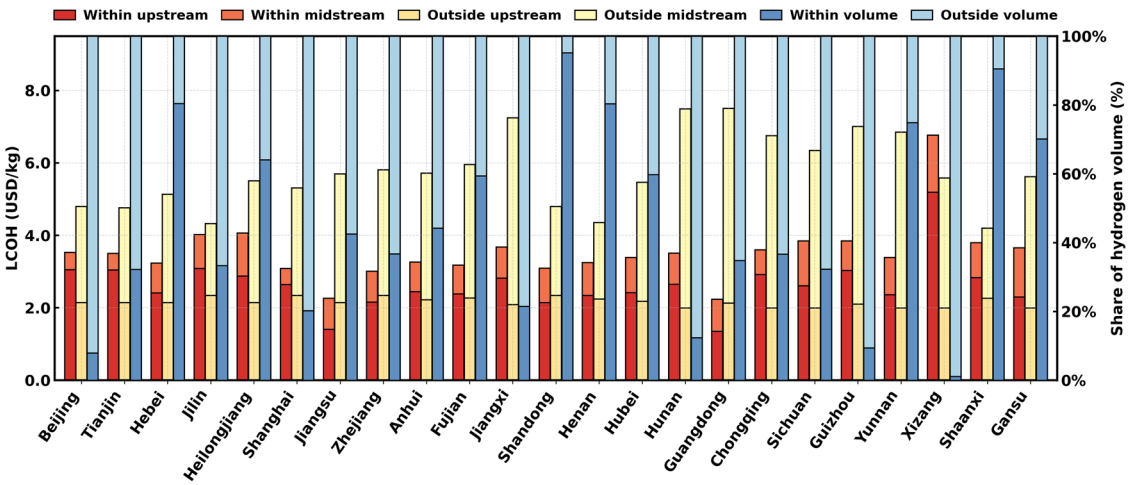

Fig. 7 | Supply-chain LCOH and hydrogen structure for importing provinces under model-based 2020 reference. This figure shows the decomposition of LCOH (left axis) and the share of hydrogen supply volume (right axis) under model-based 2020 reference. The supply-chain LCOH for each province is computed as a technology-mix-weighted value that combines upstream production costs and midstream S&T costs according to the supply shares of different hydrogen routes. The four cost components represent upstream production within the province, midstream S&T within the province, upstream production outside the province, and midstream S&T for interprovincial delivery. The right axis shows the share of hydrogen sourced within provinces compared with that imported from other provinces. For each importing province, the external supply value reflects the minimum delivered cost across out-of-province sources.

pipeline and trucking systems. Therefore, coastal demand centers face particularly high external S&T costs, including Jiangsu, Zhejiang, Guangdong, and Fujian.

Discussion and conclusion

China's provincial hydrogen system is shaped by the joint interaction of upstream production costs and midstream S&T costs. These two cost components largely determine where hydrogen can be produced economically, how it can be transported across regions, and which interprovincial routes become viable, thereby jointly determining the spatial configuration, transport mode selection, and concentration pattern of national hydrogen infrastructures. Currently midstream S&T accounts for about 20–50% of delivered cost, and flows concentrate along a limited set of corridors that connect the northwest and the north to eastern and southeastern demand centers. These regularities indicate that planning should treat costs and network design within a single optimization framework rather than as sequential choices.

Under the 2060 carbon-neutrality scenarios, total interprovincial hydrogen flows reach 30 Mt/yr, 60 Mt/yr, and 103 Mt/yr across low, moderate, and high demand scenarios, respectively. The economically optimal pipeline mileage is estimated at ~59,000 kilometers, with a flow-weighted average transportation distance of about 2522 kilometers.

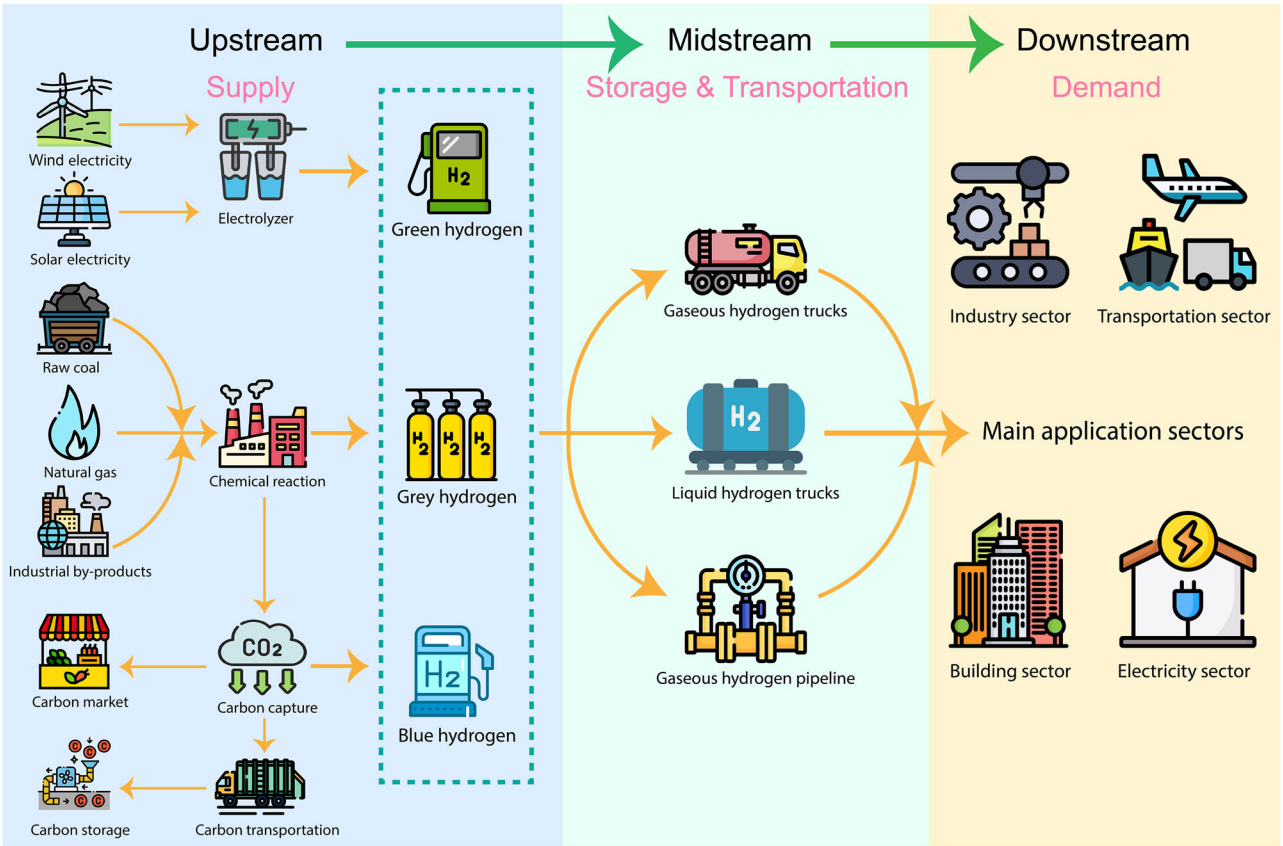

Fig. 8 | Research boundary. This figure illustrates the integrated research boundary of the hydrogen energy supply chain, structured into three interconnected stages: upstream (supply), midstream (S&T), and downstream (demand). In this study, storage is not modeled as a standalone module but is integrated within the midstream S&T system. Storage-related costs are represented in an aggregated form within the techno-economic cost structures of different transport modes. This visualization highlights the lifecycle flow of hydrogen from production to end-use, while also emphasizing carbon management and sectoral application.

Applying a unit capital cost of 0.93 million USD/km (about 6.44 million RMB/km[47]) yields a total investment of ~54.9 billion USD for the 2060 backbone pipelines (about 378.8 billion RMB). The number of pipeline-eligible province pairs remains 25 across all scenarios, confirming that scaling is achieved by expanding the capacity of a few continental-scale trunk corridors. Two mechanisms explain this outcome. The production cost gradient, driven by resource endowments and power prices, remains in place as demand grows, so inland producers retain cost advantages. Pipeline scale economies strengthen with volume and continuity, so incremental demand is most economically served by diverting additional flow onto the same long trunks, which lengthens the typical haul.

As interprovincial hydrogen trade expands, the spatial configuration of the supply network evolves, and provinces will play different roles within the national system. This shift occurs because production and demand do not grow uniformly across regions. Inland provinces with abundant renewable resources are increasingly emerging as large-scale exporters, while coastal industrial centers are becoming major destinations for long-distance hydrogen imports. Consequently, trade corridors extend, and the relative positions of provinces within the network change as some evolve into exporters, others into importers, and still others into transit hubs. Inner Mongolia's exports, which are currently concentrated in Beijing-Tianjin-Hebei and Jiangsu, are expected to extend by 2060 beyond the Bohai Rim toward the Yangtze River basin and South China as distant coastal sinks gain prominence. Qinghai and Xinjiang, which primarily supplied Sichuan-Chongqing and nearby markets currently, increasingly deliver directly to East China by 2060, reducing reliance on short interprovincial relays and contributing to longer average hauls. Several provinces change net status: Xizang, Heilongjiang, Hainan, and Guangxi become net exporters, whereas Liaoning and Shanxi become net importers, consistent with shifts in local industrial demand, improvements in renewable resource utilization, and falling unit costs for long-distance transport once trunks aggregate larger volumes.

These findings motivate a policy and engineering agenda that prioritizes backbone development before feeder networks and aligns provincial plans with corridor economics. Planning should prioritize trunk pipelines that connect inland producers to eastern and southeastern sinks, followed by regional feeders and storage hubs at interior and coastal nodes to raise utilization and lower delivered cost. The divergence between intra-provincial and interprovincial LCOH underscores the need for coordinated spatial planning in which provinces with weak renewable resources but strong industrial demand is treated as import-dependent demand centers under harmonized production targets, unified gas-quality and pressure standards, and shared provincial-level system modeling. Technology policy should differentiate by context. AE, which is often cost-competitive in inland provinces, is suitable for large-scale production deployment, whereas PEM, with greater responsiveness and modularity, is better suited to demand centers where land and grid constraints bind. Market formation requires incentives and regulatory rules that reflect full-chain costs, including midstream S&T. Options include cross-provincial subsidies, adjustments to carbon pricing that internalize transport effects, and tariff schemes based on distance and throughput, with entry and exit pricing and transparent capacity booking to align private incentives with social least-cost corridors.

While this study focuses on hydrogen delivery in the gaseous and liquid forms, alternative hydrogen carriers such as ammonia and LOHCs may offer complementary pathways for long-distance transport under different system configurations, which warrants further investigation in future work. In addition, electricity transmission represents an important

alternative pathway for addressing spatial mismatches between renewable resources and hydrogen demand. In the present framework, the trade-off between local hydrogen production from renewable power and long-distance renewable power transmission via UHV lines for remote hydrogen production is not analyzed yet. Future work could extend this analysis by jointly optimizing electricity and hydrogen transport infrastructures to better reflect their substitution and complementarity at the system level.

Another limitation concerns the model-based 2020 reference scenario. This reference scenario is designed to provide a consistent analytical benchmark, but it does not capture all evolving infrastructure developments observed in recent years. This uncertainty may affect the interpretation of the projected 2060 network configuration through path-dependent infrastructure development and flow allocation. Therefore, the 2060 pipeline results should be interpreted as cost-optimal projections under the modeled baseline assumptions, rather than as direct forecasts of actual infrastructure evolution. Future research could incorporate more detailed and dynamically updated infrastructure data to better represent the evolution of hydrogen transportation networks.

Methods

Research boundary

We define the research boundary for this study (Fig. 8), which covers the entire hydrogen value chain across 31 provinces, including upstream production, midstream S&T, and downstream end-use sectors. In this study, the analysis focuses on hydrogen delivery in its gaseous and liquid forms. Alternative long-distance transport routes, such as hydrogen carriers (e.g., ammonia and LOHCs), are not explicitly modeled. This design allows us to isolate the cost structure associated with hydrogen production and physical transportation, while maintaining a consistent system boundary and avoiding additional uncertainties related to carrier conversion and reconversion processes.

Upstream production cost

Following the framework proposed by Man et al.[27], this study calculates the upstream production cost of green hydrogen, coal-based hydrogen, and natural-gas-based hydrogen using a life-cycle cost model for each production pathway. The model encompasses various cost components, including initial investment cost, operation and maintenance (O&M) cost, taxes and salvage value[48], which can be represented as follows:

$$C_{hydrogen1} = \sum_{n=1}^{N}(C_I^n + C_o^n + C_T^n)(1+r)^{-n} - V_R(1+r)^{-n} \quad (1)$$

where $C_{hydrogen1}$ denotes the levelized upstream production cost of each hydrogen production pathway, including green hydrogen and fossil-based hydrogen routes (coal-based and natural-gas-based hydrogen). C_I^n denotes the initial investment cost in the n th year. C_o^n denotes the O&M cost in the n th year. C_T^n denotes the total tax expenditures, which includes value-added tax, sales and surcharges tax, and income tax in the n th year. V_R indicates the salvage value at the end of the hydrogen project life. N denotes the entire life of the project in terms of year, and r denotes the discount rate.

This study estimates the upstream production cost of hydrogen from industrial by-product and blue hydrogen by incorporating unit production prices and the corresponding deployment rates across provinces. On the one hand, for hydrogen from industrial by-product, the main costs of hydrogen production include raw material costs, purification costs, equipment investment, and operating costs. This study obtains from an article published by the *Propaganda Department of the Former Banner Committee of Etuoke*[49] that the comprehensive production cost of hydrogen from industrial by-product is ~1.35–3.25 USD/kg (about 9.29–22.40 RMB/kg). To estimate the unit production cost of hydrogen from industrial by-product at the provincial level, this study adopts a linear normalization interpolation method based on each province's industrial added value. The underlying assumption is that provinces with higher industrial activity, represented by greater industrial added value, tend to have greater availability and utilization potential of industrial by-product hydrogen resources, resulting in lower unit costs. The method is formulated as follows:

$$C_{hydrogen2} = C_{\max} - (C_{\max} - C_{\min}) \times \frac{V_i - V_{\min}}{V_{\max} - V_{\min}} \quad (2)$$

where $C_{hydrogen2}$ denotes the levelized upstream production cost of hydrogen from industrial by-product, $C_{\max}$ is set to 22.4 RMB/kg, $C_{\min}$ equal to 9.29 RMB/kg, V_i is the industrial added value of province i, $V_{\max}$ and $V_{\min}$ are the maximum and minimum industrial added values among all 31 provinces. This approach ensures that provinces with the highest industrial output are assigned the lowest unit costs within the specified range, and vice versa. The industrial added value of 31 provinces derives from the *National Bureau of Statistics*.

On the other hand, compared with the coal-based hydrogen upstream production process, only the additional CCUS-related costs are added to the blue hydrogen production process[33]. This study classifies coal-based hydrogen, natural-gas-based hydrogen, and industrial by-product hydrogen as grey hydrogen. The total cost of CCUS for blue hydrogen is estimated by summing the costs associated with carbon capture, CO_2 transportation, and CO_2 storage. Accordingly, the capital investment cost of CCUS system is assessed based on the respective expenditures of these three components. The calculation equation is as follows:

$$C_{ccus} = Q_{carbon} \times P_C + Q_{carbon} \times P_T \times D_T + Q_{carbon} \times P_S \quad (3)$$

where C_{ccus} is the total cost of CCUS for blue hydrogen, Q_{carbon} denotes the CO_2 capture volume, P_C denotes the unit price of CO_2 capture, P_T denotes the unit price of CO_2 transportation, D_T denotes the transportation distance, and P_S denotes the unit price of CO_2 storage.

The production of blue hydrogen is further calculated using the average deployment ratio of CCUS technologies for blue hydrogen, as well as the corresponding CO_2 capture rate. To estimate the provincial-level production volumes of grey hydrogen and blue hydrogen, as well as their relative proportions, this study considers three CCUS deployment scenarios for blue hydrogen: 100%, 25%, and 20%, respectively. These scenarios are derived by comparing the total CO_2 emissions from coal-based hydrogen processes with the actual national CCUS capture capacity. The CO_2 capture rate is set at a median value of 92.5%, with a range between 90% and 95%, reflecting typical capture efficiencies observed in large-scale CCUS application.

In this study, the upstream production cost of blue hydrogen is calculated as the product of the unit upstream production cost of blue hydrogen and the corresponding production volume. The unit upstream production cost of blue hydrogen is defined as the sum of the unit production cost of grey hydrogen and the allocated unit cost of CCUS.

The detailed calculation process is presented as follows:

$$C_{hydrogen3} = C_{unit} \times Q_h \quad (4)$$

where $C_{hydrogen3}$ denotes the total upstream production cost of blue hydrogen, C_{unit} represents the unit upstream production cost of blue hydrogen (including both grey hydrogen production and CCUS costs), and Q_h denotes the production volume of blue hydrogen.

Specifically, based on the total CCUS cost derived from Eq. (3) the CCUS unit costs for the three grey hydrogen production pathways are allocated according to their respective hydrogen production shares. These CCUS unit costs are then added to the corresponding unit production costs of the three grey hydrogen pathways to obtain the unit production costs of blue hydrogen. Finally, using Eq. (4), the total upstream production cost of blue hydrogen is calculated by multiplying the blue hydrogen unit cost by its production volume. More detailed calculation process can be found in the Supplementary Information.

Midstream S&T cost

In this section, this study divides hydrogen S&T costs into two parts: S&T within province and S&T outside province. Besides, this study divides provinces into import provinces and export provinces. Importing provinces are defined as those where hydrogen demand exceeds local supply, whereas exporting provinces are those where hydrogen supply exceeds local demand.

For the S&T within province, both importing and exporting provinces are involved. The cost calculation consists of three components: transport distance, hydrogen transport volume, and unit transport cost. In this study, the intra-provincial transport distance is approximated by each province's intra-provincial transport radius, defined as the straight-line average distance from the geographic centroid of the province to its farthest and nearest boundary points. For exporting provinces, the hydrogen transport volume corresponds to the province's total hydrogen demand, whereas for importing provinces, it corresponds to their hydrogen production volume. Three S&T modes are considered in this study: gaseous hydrogen trucks (G-H_2), liquid hydrogen trucks (L-H_2), and gaseous hydrogen pipeline (P-H_2)[34]. Due to the absence of sub-provincial hydrogen infrastructure data, as well as the provincial-level spatial resolution adopted in this nationwide assessment, this study represents intra-provincial hydrogen transport using a simplified distance-based weighting scheme. This scheme is designed to capture the distance-dependent cost characteristics of alternative transport modes while maintaining computational tractability. Specifically, when the transport distance is less than or equal to 200 km, G-H_2 accounts for 90%, L-H_2 accounts for 10%, and P-H_2 accounts for 0%; When the transport distance is less than or equal to 600 km, G-H_2 accounts for 70%, L-H_2 accounts for 25%, and P-H_2 accounts for 5%; When the transport distance is greater than 600 km, G-H_2 accounts for 50%, L-H_2 accounts for 40%, and P-H_2 accounts for 10%. These proportions are not intended to reproduce observed transport shares, but rather to approximate the relative cost competitiveness of alternative transport modes across different distance ranges. This assumption is consistent with previous studies showing that compressed gaseous hydrogen is more cost-effective over short transport distances, whereas liquefied hydrogen and pipeline transportation become increasingly competitive as transport distance increases[50–52]. The unit transport cost for each mode is calculated following the methodology proposed by Miao et al.[34]. Based on the reported unit transport costs at 100 km and 800 km, we construct a two-point calibrated freight-rate curve in which the unit cost decreases with increasing transport distance due to the economies of scale embedded in the underlying techno-economic data. The parameters are determined using the reported unit transport costs at these two anchor distances. The calculation method for cost of S&T within province is given by the following equation:

$$S\&T_{within} = \sum_{n=1}^{N} (D_{within} \times V_{within} \times P_T)(1+r)^{-n} \quad (5)$$

where $S\&T_{within}$ denotes the cost of S&T within province, D_{within} denotes the transport distance within province, V_{within} denotes the hydrogen transport volume within province, and P_T denotes the unit price of three transport modes.

For the S&T outside province, only the importing province is involved. The transport matrix represents the geographic centroid straight-line distance between the exporting province and the importing province, defined as the sum of the transport distance within the exporting province, the transport distance within the importing province, and the trunk distance between the two provinces. Calculate the flow matrix based on the principle of minimizing costs. The calculation method for cost of S&T outside province is given by the following equation:

$$S\&T_{outside} = \sum_{n=1}^{N} (D_{outside} \times V_{outside} \times P_T)(1+r)^{-n} \quad (6)$$

where $S\&T_{outside}$ denotes the cost of S&T outside province, $D_{outside}$ denotes the transport distance outside province, $V_{outside}$ denotes the inter-provincial hydrogen transport volume, and P_T denotes the unit price of three transport modes.

Downstream demand

In this study, the total hydrogen demand in China is allocated across 31 provinces based on each province's share of the national gross domestic product (GDP). This approach yields an estimate of provincial-level hydrogen demand for the corresponding year[53]. The GDP data are obtained from *the China Statistical Yearbook* and individual provincial statistical yearbooks. The national hydrogen demand data are sourced from *the China Hydrogen Alliance*. The downstream demand is estimated using the following equation:

$$D_{provincial} = \frac{GDP_{provincial}}{GDP_{national}} \times D_{national} \quad (7)$$

where $D_{provincial}$ denotes the provincial hydrogen demand, $D_{national}$ denotes the national hydrogen demand, $GDP_{provincial}$ denotes the provincial GDP, $GDP_{national}$ denotes the national GDP.

LCOH

The calculation of supply-chain LCOH data is divided into intra-provincial and extra-provincial categories, with intra-provincial including importing and exporting provinces, and extra-provincial including importing provinces[43,45,54].

For intra-provinces, the following equation is that:

$$LCOH_{within} = \frac{C_{within} + S\&T_{within}}{\sum_{n=1}^{N} Q_{hydrogen}(1+r)^{-n}} \quad (8)$$

where $LCOH_{within}$ denotes the LCOH within province, C_{within} denotes the upstream production cost within the province, $Q_{hydrogen}$ denotes the production of hydrogen.

For extra-provinces, the following equation is that:

$$LCOH_{outside} = \frac{C_{outside} + S\&T_{outside}}{\sum_{n=1}^{N} Total_{hydrogen}(1+r)^{-n}} \quad (9)$$

where $LCOH_{outside}$ denotes the LCOH outside province, $C_{outside}$ denotes the upstream production cost outside the province, $Total_{hydrogen}$ represents the total hydrogen import volume of the importing provinces. This study assumes that the project period is 20 years. The fixed O&M costs for AE and PEM are 1.5% of the initial investment cost. The discount rate r is fixed at 5%. Furthermore, the exchange rate from USD to RMB is considered to be 6.90.

Interprovincial flow allocation

To determine the spatial allocation of hydrogen supply and interprovincial transport patterns, we develop a cost-minimization framework that allocates hydrogen flows between provinces based on supply-demand balances and transport costs.

First, for each province, net supply and demand conditions are identified by comparing local hydrogen production and demand. Provinces with surplus production are defined as exporting regions, while those with insufficient production are treated as importing regions. Based on this classification, we construct an interprovincial flow allocation model that minimizes the total cost of transporting hydrogen from exporting to importing provinces.

The optimization problem is formulated as a linear programming model:

$$\min_{x_{ij}} \sum_{i\in E}\sum_{j\in I} C_{ij}\cdot x_{ij} \tag{10}$$

Subject to:

$$\sum_{j\in I} x_{ij} \le S_i \qquad \forall i \in E \tag{11}$$

$$\sum_{i\in E} x_{ij} = D_j \qquad \forall j \in I \tag{12}$$

$$x_{ij} \ge 0 \qquad \forall i,j \tag{13}$$

where x_{ij} denotes the quantity of hydrogen transported from exporting province i to importing province j; C_{ij} represents the unit transport cost between provinces i and j; S_i is the available hydrogen surplus in exporting province i; and D_j is the hydrogen demand deficit in importing province j. E and I denote the sets of exporting and importing provinces, respectively.

Interprovincial transport costs C_{ij} are determined based on province-to-province distances and mode-specific cost assumptions. Rather than explicitly modeling transport mode selection as an endogenous decision variable, we approximate the transport cost structure using distance-dependent weighted cost functions. Specifically, the relative contributions of gaseous hydrogen trucking, liquid hydrogen trucking, and pipeline transportation are represented through distance-based weighting schemes, reflecting their typical techno-economic characteristics across different transport ranges. The resulting unit transportation cost C_{ij} represents the distance-dependent composite cost derived from different transport modes. This approach enables the representation of variation in transport costs across distances while maintaining computational tractability at the provincial resolution. The resulting least-cost interprovincial hydrogen flow matrix provides the basis for subsequent analysis of transport patterns and infrastructure deployment.

Pure hydrogen pipeline

We assess whether interprovincial hydrogen flows warrant dedicated pure-hydrogen pipelines by jointly considering transport distance and annual flow volume. For each origin-destination pair, the evaluation follows a three-step procedure. First, we construct mode-specific unit transport cost functions for trucking and pipelines. Second, we compare these costs to identify the distance-throughput combinations under which pipelines become more economical than trucking. Third, origin-destination pairs that satisfy these conditions are retained to construct the set of cost-justified interprovincial hydrogen pipeline corridors.

First, for each mode m (pipeline or truck), we construct a mode-specific unit S&T cost function $C_m(d,q)$, where d is the transport distance and q denotes the expected annual hydrogen flow between an origin-destination pair. Trucking costs scale approximately linearly with distance and throughput, while pipeline costs consist primarily of capital recovery and a small operating component. For pipelines, the capital investment is annualized using a standard engineering-economics formulation:

$$C_{pipe}(d,q) = \frac{CAPEX(d)\times r\times(1+r)^n}{(1+r)^n-1}\times\frac{1}{q} + O\&M_{pipe} \tag{14}$$

where $CAPEX(d)$ refers to the capital expenditure required for the pipeline, which is directly proportional to the pipeline length d. This means that the construction costs for pipeline installation typically increase with the length of the pipeline because longer pipelines require more materials, labor, and infrastructure. n is the lifetime of pipeline, and r is the discount rate. $1/q$ represents the reduction in transportation cost per kilogram as the annual volume of hydrogen transported q increases. Specifically, as q increases, the per-kilogram transport cost decreases due to economies of scale. We assume a discount rate of 5% and an economic lifetime of 20 years for hydrogen pipelines. The capital expenditure is set to ~0.93 million USD/km (about 6.44 million RMB/km[47]), and annual O&M costs are represented by 5% share of capital expenditure. In this formulation, pipeline capital costs are represented using a constant unit investment cost per kilometer, derived from literature-based techno-economic data[47]. This corresponds to a typical pipeline design, without separately modeling pipeline diameter. Minimum throughput requirements are represented through the distance-throughput feasibility conditions applied in the model, while maximum throughput constraints are not explicitly imposed, as large-scale flows can be approximated through capacity expansion or parallel pipeline deployment within the modeling framework.

Trucking transport costs are modeled using a distance-dependent unit cost function that reflects the operational characteristics of hydrogen trailer operations. Unlike pipelines, which involve substantial fixed capital investment and consequently exhibit strong economies of scale, trucking operates as a trip-based transport mode. It is dominated by variable operating costs, including fuel consumption, driver labor, and trailer depreciation. In addition, hydrogen loading, unloading, and handling activities introduce fixed costs that are amortized over the total distance traveled, leading to per-kilogram costs that decline with increasing transport distance.

To represent these features, the unit trucking cost for mode m (gaseous or liquid hydrogen) is expressed as a distance-dependent function:

$$C_{truck}(d) = V_{truck} + \frac{f_{truck}}{d} \tag{15}$$

where V_{truck} denotes the long-distance marginal cost, and f_{truck} represents the fixed handling and trailer preparation costs that decline on a per-kilogram basis as distance increases. The parameters V_{truck} and f_{truck} are calibrated using representative short-haul (100 kilometers) and long-haul (800 kilometers) cost observations, ensuring that the function reproduces observed cost reductions with distance and remains consistent with typical hydrogen trucking practices. Importantly, because trucking relies on discrete trailer trips rather than continuous-flow infrastructure, its unit cost is independent of annual transported volume q. More details are shown in Supplementary Table 8.

Second, for each origin-destination pair, we identify the economically preferred transport mode by comparing the unit delivered costs of trucking and pipelining at the corresponding distance and annual flow levels. Pipeline deployment is considered economically viable only when both distance and flow conditions are satisfied. Specifically, pipelines are selected only for origin-destination pairs with sufficiently long transport distances and sufficiently large annual hydrogen flows, ensuring that economies of scale can be realized and pipeline transportation becomes cost-competitive relative to trucking.

Third, for origin-destination pairs that satisfy the distance-throughput feasibility conditions, pipeline deployment is considered as a candidate option, and the spatial pattern of economically justified pipelines is constructed. For each scenario, all origin-destination pairs meeting the distance-throughput criteria are retained as pipeline candidates, and their associated flows are used to assemble the interprovincial pipeline network. The resulting set of economically viable pipeline links is then superimposed on the provincial map to visualize the emergent hydrogen transmission corridors across China.

Finally, the optimization evaluates all feasible provincial inflow and outflow options simultaneously, allowing pipeline flows to aggregate along trunk corridors when this reduces total system cost. The resulting network represents the economically preferred hydrogen transport configuration under the given demand patterns and engineering cost assumptions.

Data availability

The source data supporting the findings of this study are available in Zenodo at https://doi.org/10.5281/zenodo.21376633.

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Author contributions

C.B., F.G. and N.Z. conceived the study and designed the overall research framework. C.B. and F.G. developed the research methods, drafted the initial manuscript, and performed data collection and preprocessing. F.G. and N.Z. provided critical feedback, contributed to interpretation of the results, and revised the manuscript.

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Competing interests

The authors declare no competing interests.

Additional information

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