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Policy Analysis

Subsidizing Grid-Based Electrolytic Hydrogen Will Increase Greenhouse Gas Emissions in Coal Dominated Power Systems

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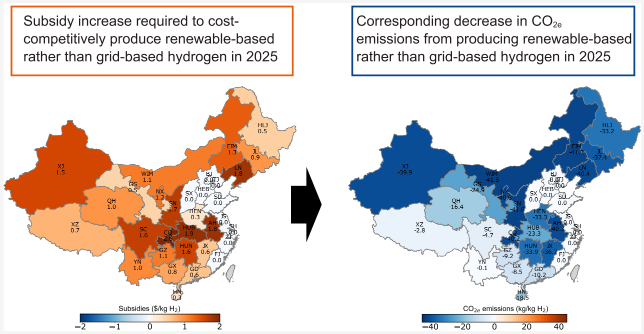
ABSTRACT: Clean hydrogen has the potential to serve as an energy carrier and feedstock in decarbonizing energy systems, especially in "hard-to-abate" sectors. Although many countries have implemented policies to promote electrolytic hydrogen development, the impact of these measures on costs of production and greenhouse gas emissions remains unclear. Our study conducts an integrated analysis of provincial levelized costs and life cycle greenhouse gas emissions for all hydrogen production types in China. We find that subsidies are critical to accelerate low carbon electrolytic hydrogen development. Subsidies on renewable-based hydrogen provide cost-effective carbon dioxide equivalent (CO_{2e}) emission reductions. However, subsidies on grid-based hydrogen increase CO_{2e} emissions even compared with coal-based hydrogen because grid electricity in China still relies heavily on coal power and likely will beyond 2030. In fact, CO_{2e} emissions from grid-based hydrogen may increase further if China continues to approve new coal power plants. The levelized costs of renewable energy-based electrolytic hydrogen vary among provinces. Transporting renewable-based hydrogen through pipelines from low- to high-cost production regions reduces the national average levelized cost of renewables-based hydrogen but may increase the risk of hydrogen leakage and the resulting indirect warming effects. Our findings emphasize that policy and economic support for nonfossil electrolytic hydrogen is critical to avoid an increase in CO_{2e} emissions as hydrogen use rises during a clean energy transition.



KEYWORDS: *renewable energy based hydrogen, electrolytic hydrogen, levelized cost of hydrogen, life cycle GHG emissions, hydrogen pipelines, subsidies*

■ INTRODUCTION

Low-carbon hydrogen (H_2) is critical for the clean-energy transition, providing long-term energy storage in the power sector and offering ways to reduce emissions in industry and heavy transport sectors that will be difficult or expensive to electrify. Hydrogen can be produced from various primary energy resources, including coal, natural gas, renewable energy, nuclear, and biomass, which have varying implications for greenhouse gas (GHG) emissions.[1]

Currently, nearly all hydrogen in China is either produced directly from fossil fuels (55% from coal gasification and 14% from steam methane reforming (SMR)) or as a byproduct of petroleum refining (28%), with only 1% coming from water electrolysis.[2] Producing 1 kg of coal- or SMR-based hydrogen emits roughly 19 and 10 kg of CO_2, respectively.[3] In 2020, hydrogen production from fossil fuels in China emitted ∼322Tg of CO_2, equivalent to 25% of total CO_2 emissions from industrial processes, a number expected to rise with increasing hydrogen demand.[4] Industrial processes include production of non-metallic mineral products, chemical, and metal products, as well as production and consumption of halocarbons and sulfur hexafluoride.[4]

Electrolytic hydrogen can be categorized by its electricity source: grid-based hydrogen generated using electricity from the power grid and renewable-based hydrogen generated directly from renewable electricity. Grid-based hydrogen is cheaper than renewable-based hydrogen in most provinces, requiring lower subsidies for its development. However, grid-based electricity generation relies heavily on coal and, thus, has substantial GHG emissions. Subsidizing grid-based hydrogen production would likely increase GHG emissions relative to coal-based hydrogen

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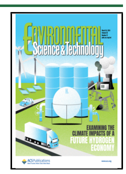

production, whereas hydrogen directly generated from renewable energy has minimal GHG emissions.

China aims to reach peak carbon emissions by 2030 and to achieve net-zero carbon emissions by 2060. To minimize cumulative carbon emissions, accelerating the transition to decarbonized hydrogen production is crucial. However, high production costs are a significant barrier to the adoption of clean electrolytic hydrogen. Currently, renewable-based hydrogen and grid-based hydrogen cost 2−6 times and 1.6−3 times more than coal- or SMR-based hydrogen, respectively.[2,5−7] Until renewable-based hydrogen becomes cost-competitive, large-scale development of hydrogen is likely to increase GHG emissions by expanding fossil- and grid-based electrolytic hydrogen production. To rapidly decarbonize the hydrogen production process, it is essential to accelerate the shift from fossil- to renewable-based hydrogen. While some provincial governments (e.g., Inner Mongolia and Gansu) have established hydrogen production goals, their plans lack a specific focus on renewable-based electrolytic hydrogen. Moreover, there is little research at the provincial level that compares life cycle GHG emissions and levelized costs of hydrogen ($LCOH_2$) across all hydrogen production technologies. Our work provides valuable insights into the trade-offs between subsidies and GHG emissions in the development of the hydrogen industry at the provincial level in China.

Subsidies play a significant role in developing emerging technologies. To accelerate the electrolytic hydrogen transition, subsidies on hydrogen-related devices and hydrogen used for transportation have been deployed in different regions as pilot projects.[8,9] Since renewable-based hydrogen costs 2−6 times more than coal- or SMR-based hydrogen,[2,4,5] greater subsidies are required to make renewable hydrogen cost competitive and to drive commercial production.

Renewable-based hydrogen production costs vary significantly by location due to renewable resource availability. Transporting renewable energy-based electrolytic hydrogen through pipelines from low- to high-cost provinces can reduce costs. However, minimizing leakage is crucial since hydrogen is an indirect GHG.[10,11] As hydrogen demand increases, pipeline transport becomes the most cost-effective option.[12] Using existing natural gas pipelines can reduce transmission costs by over 60% compared to building new pipelines.[13] However, this will likely increase the risk of hydrogen leakage. Alternatively, constructing new infrastructure can reduce these leakage risks but will entail substantial costs. There is little research on how hydrogen pipeline transport impacts provincial $LCOH_2$ and life cycle GHG emissions.

Our study compares provincial $LCOH_2$ and life cycle GHG emissions from a variety of hydrogen sources, including coal, natural gas, grid, and renewable electricity. We examine the trade-offs in GHG emissions resulting from subsidies for both grid-based and renewable-based electrolytic hydrogen production, with the goal of achieving electrolytic hydrogen production that is cost-competitive with fossil-based hydrogen production, while minimizing GHG emissions from 2025 to 2050. We use an integrated assessment approach in conjunction with a life-cycle analysis to quantify the trade-offs between financial subsidies and life cycle GHG emissions in accelerating electrolytic hydrogen development in China.

In our study, we examine when grid or renewable electrolytic hydrogen will become cost-competitive without subsidies and which provinces will lead or lag in this. We also analyze the trade-offs between GHG emissions and subsidy costs as well as whether both renewable- and grid-based hydrogen production should be subsidized. Finally, we explore how the pipeline network can be developed to minimize GHG emissions during interprovincial transport, including CH_4 leakage, H_2 leakage, and CO_2 emissions.

■ METHODS

Scenario Design. We design two primary scenarios to evaluate the difference in costs and GHG emissions of electrolytic hydrogen development pathways relative to coal-based hydrogen. (1) The Minimum-Subsidy scenario subsidizes electrolytic hydrogen production using the lowest cost electricity (e.g., grid-based electricity). This scenario will encourage the development of the electrolytic hydrogen industry but will increase GHG emissions relative to using electrolytic hydrogen from renewable electricity. (2) The Renewable-Subsidy scenario subsidizes electrolytic hydrogen production produced using only the lowest cost renewable energy. This scenario minimizes GHG emissions of hydrogen production but requires higher subsidies than those of the minimum subsidy scenario. See Supporting Information (SI) Note S1 for details.

We also test two additional scenarios using potential interprovincial pipeline networks: (3) The Minimum-Subsidy-Pipeline scenario is the same as the Minimum-Subsidy scenario but includes interprovincial hydrogen transport through pipelines. This scenario will encourage the development of electrolytic hydrogen in the provinces where it costs the least to produce and allow it to be transported to provinces where it is needed. (4) The Renewable-Subsidy-Pipeline scenario is the same as the Renewable-Subsidy scenario but includes interprovincial hydrogen transport through pipelines. This scenario will encourage the development of electrolytic hydrogen from only renewable energy in the provinces where it costs the least to produce and allow it to be transported to provinces where it is needed.

Levelized Cost of Hydrogen Production. The levelized cost of energy, LCOE, is a commonly used measurement of the cost per unit energy produced over the energy production source's lifetime. The costs include capital expenditures, operational and maintenance expenditures, and fuel costs.[5] Here, we employ $LCOH_2$ to evaluate the economic performance of hydrogen production. $LCOH_2$ is determined by many factors, such as electricity costs, fuel costs, capital costs and operation and maintenance (O&M) costs of water electrolysis, conversion efficiency, and interest rates. See details of the equations in SI Note S2.

For coal, natural gas, oil, hydro, and nuclear power plants, their capital costs, and operational and maintenance expenditures are derived from He et al.[14] Costs of wind energy, solar energy, batteries, and water electrolysis are obtained from the annual technology baseline (ATB) 2021[15] and IRENA, 2020[5] (See details in SI Notes S3 and S4.). Discount rates also influence the $LCOH_2$ estimates. We estimate $LCOH_2$ for each hydrogen production technology with a moderate (4%) discount rate.[15−18] To further analyze the impacts of a discount rate on $LCOH_2$, we conducted two sensitivity analyses considering low (half of the moderate scenario − 2%) and high discount rates (double of the moderate scenario − 8%) on $LCOH_2$. This study does not include the cost of water because its cost is tiny compared to the other hydrogen production costs.[19]

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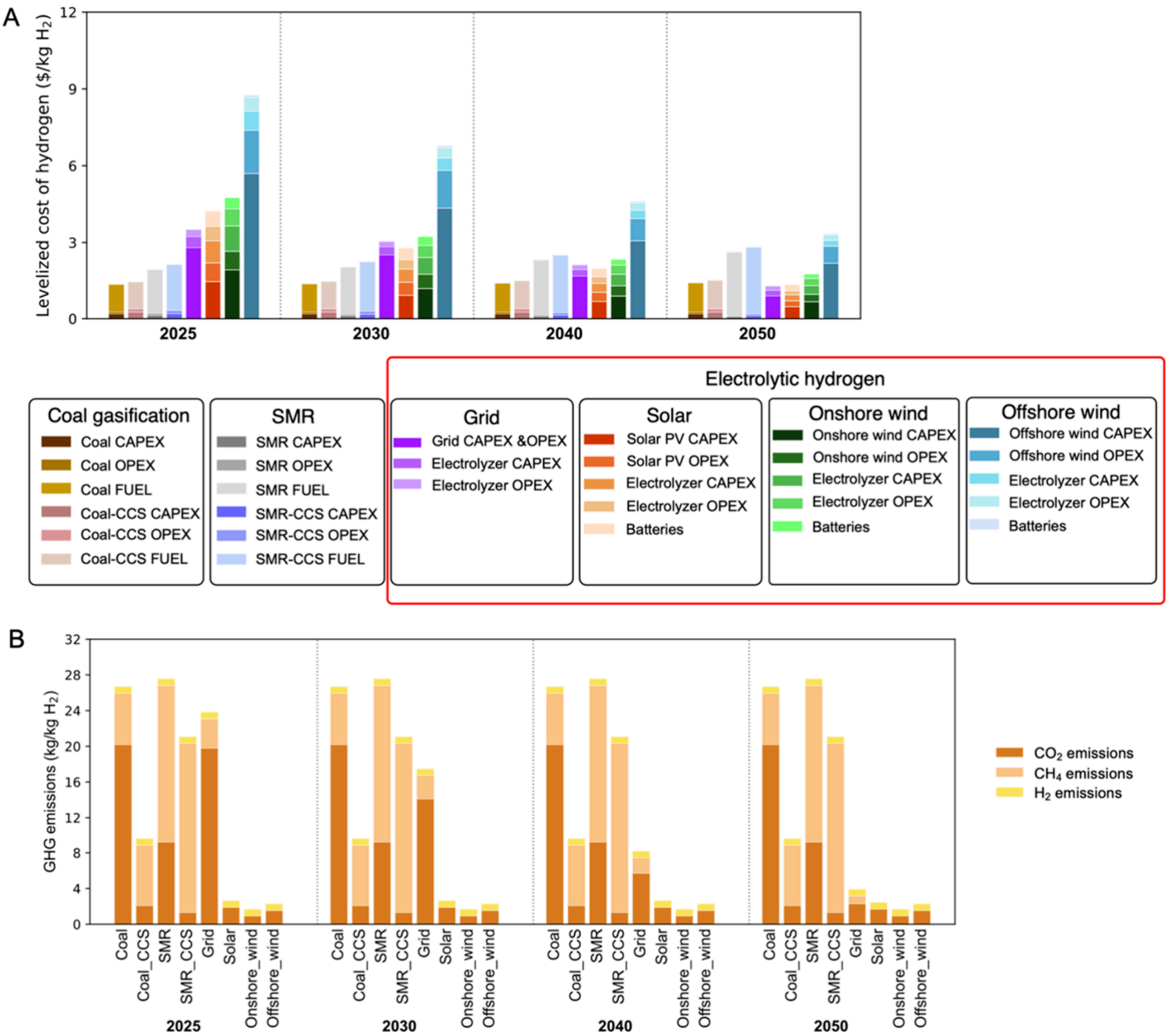

Figure 1. China's national average (A) $LCOH_2$ and (B) GHG emissions using GWP20 for hydrogen production technologies (coal gasification, steam methane reforming, electrolytic hydrogen from grid-based, solar, onshore wind, and offshore wind) with rapid cost decreases of renewable energy in 2025, 2030, 2040, and 2050. CAPEX: Capital expenditures; OPEX: Operational expenditures; Fuel: fuel costs. Lifecycle GHG emissions include methane and hydrogen leakage, assuming moderate methane and hydrogen leakage rates. (See $LCOH_2$ with slow and moderate cost decrease of renewable energy in Figures S4 and S5. See comparison of GHG emissions using GWP20 and GWP100 with low and high leakage rates in Figures S6–S8.)

Life Cycle GHG Emission Estimates. Life cycle assessment (LCA) quantifies cradle-to-grave environmental and net-energy impacts of the energy supply system.[20] This facilitates consistent comprehensive comparisons between energy technologies. We use LCA to estimate provincial GHG emissions from upstream processes (e.g., module manufacture, installation, raw material extraction) and operational processes (e.g., fuel transport and combustion, plant operation, and maintenance) of hydrogen production. The proportion of GHG emissions from each lifecycle stage differs by technology. For fossil-fueled technologies, fuel combustion during the operation of the facility emits the vast majority of GHGs. For renewable energy technologies, most GHG emissions occur upstream of operation.[21]

We estimate CO_{2e} emissions for methane and hydrogen leakage by multiplying the kilogram leakage of GHGs by their respective global warming potential (GWP). Table S5 provides the parameters and sources for the GWP computations. Given the large variation in measured leakage rates, we also include sensitivity analyses for both methane and hydrogen leakage rates. (See details in SI Note S5, Tables S4 and S6.) We collect emission factors for various stages of each technology,[10,20−27] as shown in Table S7. Our analysis considers emissions of GHGs (CO_2, methane, hydrogen) using both GWP20 and GWP100 metrics, accounting for both direct and indirect climate effects. Our method captures both short- to mid-term climate impacts using GWP20 and the longer-term effects represented by GWP100. Results in the main text are based on GWP20, while findings with GWP100 are detailed in the SI.

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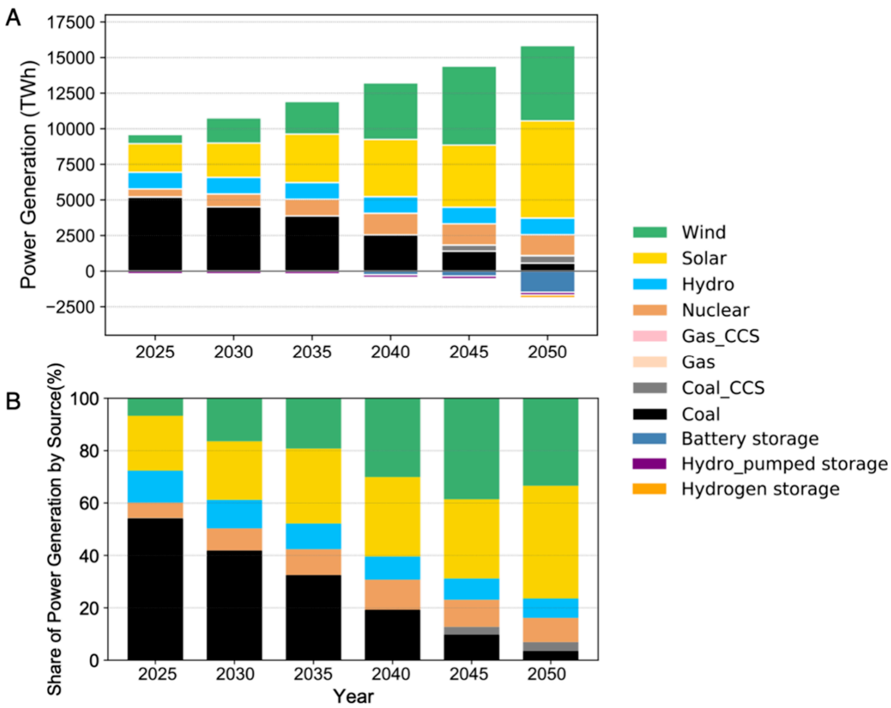

Figure 2. SWITCH-China model results of (A) electricity generation/discharge and (B) share of power generation by energy source under the carbon emission cap decreasing from 2025 to 2050.

SWITCH-China Model. We extend the SWITCH-China capacity expansion model[28] to analyze our scenarios. SWITCH-China is an optimization model that determines the optimal installed capacities of generators and transmission lines to meet a specific demand. The optimal solution minimizes the cost of producing and delivering electricity while satisfying a set of operational constraints (e.g., electricity supply must equal demand at each time-step, etc.).[29,30] Total costs include capital and fixed O&M costs of power plants and storage projects, fuel costs, and transmission and distribution infrastructure costs.[14] We set a decreasing carbon emission cap as a constraint. The carbon emission cap is based on a 2.0 °C global warming scenario from Zhuo et al.[31] The annual carbon emission cap decreases from 4.39 Gt in 2025 to 0.48 Gt in 2050. SWITCH-China minimizes the total costs of installed capacity and power generation from power generators with various energy sources under each year's carbon emission cap constraints.

Hydrogen Pipeline Network Selection Model. We develop a simple model to design a hydrogen pipeline network to achieve the lowest $LCOH_2$ for each province in China. The cost-effectiveness of pipelines is determined by the distance between two provincial capitals and the difference in $LCOH_2$ between these two provinces. If the cost of pipelines between these two provinces is lower than the difference in $LCOH_2$ between them, then pipelines will be selected for construction. Detailed equations and corresponding notes can be found in SI Note S6.

RESULTS AND DISCUSSION

National Analysis of Levelized Costs of Hydrogen by Generation Technology. The national average $LCOH_2$ of various hydrogen production technologies from 2025 to 2050 is shown in Figure 1A. Coal-based hydrogen production is projected to remain the most cost-effective option until 2040. SMR-based hydrogen is more expensive than coal-based hydrogen in China due to the high cost of natural gas. Fossil-based hydrogen with CCS has higher $LCOH_2$ compared to both coal and SMR-based hydrogen because of CCS costs. Electrolytic hydrogen only becomes cost-competitive with gas after 2030 20 and with coal after 2040 due to the higher capital, water electrolysis, and battery costs required for electrolysis. However, by 2030 solar based electrolytic hydrogen is projected to be cost-competitive with grid-based hydrogen production.

The $LCOH_2$ of electrolytic hydrogen varies by the electricity source (Figure 1A). Grid-based hydrogen is projected to have the lowest $LCOH_2$ in 2025, while solar- and onshore wind-based hydrogen are projected to be cheaper than grid-based hydrogen starting in 2030. The proportion of the $LCOH_2$ contributed by each component differs by technology; for example, SMR-based hydrogen has a higher share of costs coming from fuel than coal-based hydrogen due to China's costly natural gas. Offshore wind-based hydrogen has higher capital, operation and maintenance costs than on-shore wind due to challenging operational conditions. Additionally, renewable-based hydrogen requires on-site battery storage for stable electrolyzer operation during intermittent renewable energy supply, leading to additional battery costs. High (8%) and low (2%) discount rates result in 4%−24% higher $LCOH_2$ and 3−12% lower $LCOH_2$ compared to the moderate discount rate (4%), respectively, as shown in Table S8.

National Analysis of Life Cycle GHG Emissions. The lifecycle GHG emissions of hydrogen production technologies vary greatly. Although coal-based hydrogen has the lowest $LCOH_2$, it introduces the second highest life cycle GHG emissions using GWP20 from 2025 to 2050 (Figure 1B). SMR-based hydrogen has the highest life cycle emissions. Grid-based hydrogen production has the third-highest emissions in 2025, but these emissions decrease as the power grid decarbonizes. By 2025, coal will still dominate the power grid (Figure 2), accounting for over 50% of China's electricity. Energy efficiency

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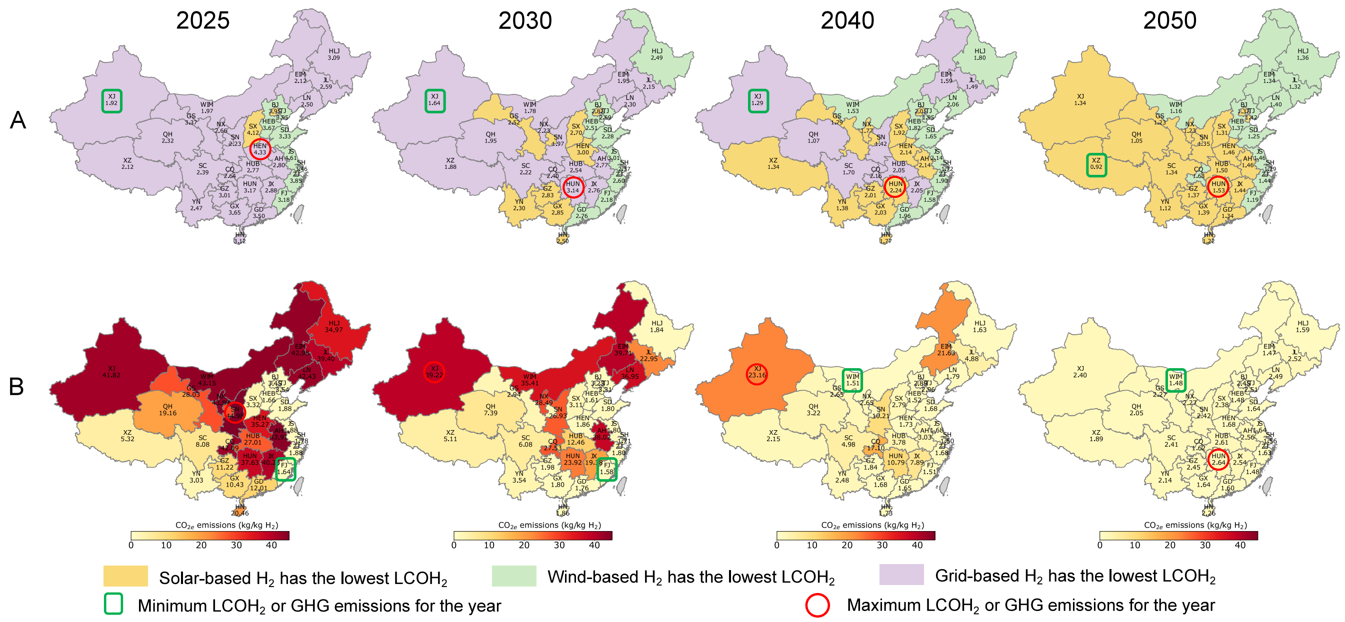

Figure 3. (A) Lowest levelized cost and (B) corresponding life cycle CO_{2e} emissions using GWP20 of electrolytic hydrogen production by province without subsidies from 2025 to 2050. Top row (A): Colors represent the technology with the lowest $LCOH_2$ in each province, and numbers provide the actual cost (2021USD/kg H_2). Green rectangles and red circles represent the provinces with the minimum and maximum $LCOH_2$ in each year. Bottom row (B): Colors represent the CO_{2e} emissions from each province from the lowest cost technology, and numbers provide the actual CO_{2e} emissions (kg CO_{2e}/kg H_2) from that technology. Green rectangles and red circles represent the province with the resulting minimum and maximum GHG emissions each year. (See the results using GWP100 in Figure S10.)

of electrolytic hydrogen production (12%−43%) is much lower than hydrogen production from coal gasification and SMR (60%−76%). However, as the power system decarbonizes, GHG emissions from grid-based hydrogen production decrease dramatically from 24 to 4 kg of CO_{2e}/kg of H_2 between 2025 and 2050.

The life cycle GHG emissions of renewable-based hydrogen production are from upstream processes, including raw material extraction, module manufacturing, device production, and installation. Renewable-based hydrogen has by far the lowest GHG emissions (Figure 1B). As renewable technology continues to advance, these emissions will decrease further between 2025 and 2050. However, small variations between renewable technology emissions exist. Upstream emissions of solar PV are about double those of onshore wind in China because wind farms have higher material recycling rates (20%) than solar facilities.[20,23] Offshore wind has 70% higher upstream emissions than onshore wind[20,24−26] due to complex infrastructural needs. Thus, upstream emissions from solar, offshore wind, and onshore wind have the highest to lowest CO_{2e} emissions, respectively. These differences are tiny compared to the differences between coal-based and electrolytic grid-based hydrogen production, where over 61% of power generation in 2021 was driven by coal.

Fossil-based hydrogen with carbon capture and storage (CCS) can theoretically reduce life cycle GHG emissions by 80−90% compared with fossil-based hydrogen (Figure 1B). However, its implementation in China faces obstacles and concerns. China's ability to utilize CCS technology is debated, with the feasibility and permanence of carbon storage uncertain due to the characteristics of China's sedimentary reservoirs.[32] Moreover, the lack of effective business models, CO_2 transport pipelines, and commercialized carbon capture technologies as well as insufficient incentives and regulatory measures bring challenges to the development of large-scale CCS projects.[33] Moreover, although coal-based hydrogen production is currently the primary source of hydrogen in China, there is currently no effort to pair CCS with coal-based hydrogen production. Additionally, although SMR-based hydrogen production, the dominant form of hydrogen production in the US, could be coupled with CCS, relying on SMR may expose China to national energy security risks, given its dependence on imported natural gas (45% imported). Imported natural gas transported long-distances would also increase risk of methane leakage.[34,35]

Trade-offs between Subsidies and GHG Emissions in Provincial Electrolytic Hydrogen Production. The lowest levelized cost of electrolytic hydrogen technology shifts from grid-based to renewable-based hydrogen in most provinces over time (Figure 3A and Figure S9). We identify the province with the lowest cost of electrolytic hydrogen production before policy incentives in Figure 3A. In 2025, grid-based hydrogen is the most cost-effective in two-thirds of provinces. From 2030 to 2050, wind-based hydrogen has the lowest $LCOH_2$ in most coastal provinces (e.g., Hebei, Shandong, Jiangsu, Zhejiang, Fujian, Guangdong, and Guangxi). Solar-based hydrogen consistently has the lowest $LCOH_2$ for Beijing, Tianjin, Gansu, Shanxi, and Yunnan provinces and by 2040 has become the lowest cost option in 13 provinces (e.g., Anhui and Hubei).

Subsidizing grid-based electrolytic hydrogen in provinces with high coal-fired power generation, such as Xinjiang, western and eastern Inner Mongolia, and Ningxia, will increase life cycle GHG emissions compared with coal-based hydrogen (Figure 3B). This is due to the energy lost by converting coal first to electricity and then to hydrogen, which results in higher emissions in coal-dominated regions. For instance, Xinjiang's projected coal-fired power generation in 2025 (65% from SWITCH-China model results) leads to higher life cycle CO_{2e} emissions from grid-based hydrogen (∼42 kg of CO_{2e}/kg H_2) than coal-based hydrogen (∼27 kg of CO_{2e}/kg H_2). Subsidies in

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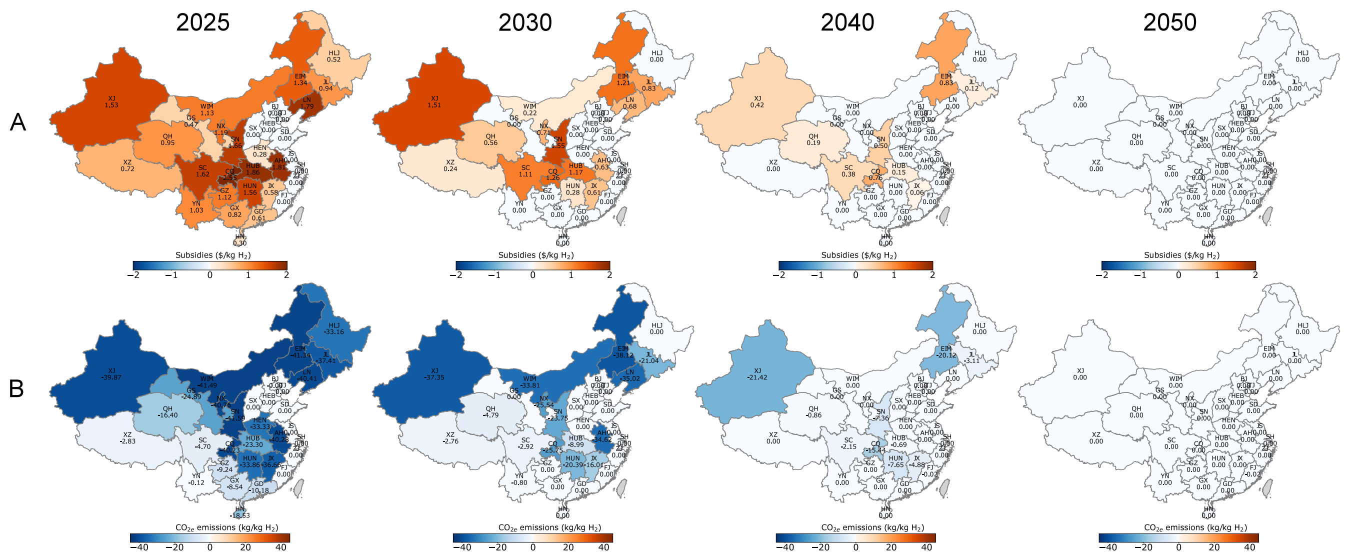

Figure 4. Provincial differences in (A) subsidies and (B) life cycle CO_{2e} emissions using GWP20 from 2025 to 2050. Top row (A): Subsidy increase required to cost-competitively produce renewable-based hydrogen rather than grid-based hydrogen (i.e., subsidies for the renewable-subsidy scenario minus subsidies for the minimum-subsidy scenario); Bottom row (B): Reduction in CO_{2e} emissions when renewable based H_2 is subsidized rather than grid-based hydrogen (i.e., CO_{2e} emissions of the renewable-subsidy scenario minus the minimum-subsidy scenario). (See the results using GWP100 in Figure S11.)

such regions could inadvertently boost GHG emissions by promoting grid- over coal-based hydrogen. However, limiting subsidies to electrolytic hydrogen obtained from renewable energy will dramatically reduce GHG emissions.

Figure 4 shows the trade-offs between subsidies and life cycle CO_{2e} emissions in accelerating grid- and renewable-based electrolytic hydrogen development by province. The renewable subsidy scenario increases subsidies by \$0.8 per kg of H_2 (47%) in 2025 relative to the minimum-subsidy scenario. As a result, in 2025, national average CO_2 emissions under the renewable subsidy scenario decrease by 19.4 kg of CO_{2e} per kg of H_2 compared with the minimum-subsidy scenario. However, benefits of high subsidies depend on local renewable resources. For example, in 2025 in western Inner Mongolia, subsidy increases of only \$1.1/kg H_2 in the renewable subsidy scenario can reduce 41.5 kg of CO_{2e} per kg of H_2 production compared to the minimum-subsidy scenario. However, in the same year in Sichuan province, subsidizing an additional \$1.8 per kg of H_2 would only reduce 4.7 kg of CO_{2e} per kg of H_2 production. Thus, subsidizing renewable-based hydrogen production in provinces rich in renewable resources provides a cost-effective mechanism to reduce GHG emissions from hydrogen production. Hydrogen produced using renewable energy in those provinces could then be exported to other provinces that would otherwise rely on fossil- or coal intensive grid -based hydrogen production.

Potential Hydrogen Pipeline Network and Impacts on Subsidies and Life Cycle GHG Emissions of Electrolytic Hydrogen from grid- and renewable-based electricity. As hydrogen demand increases in the future, interprovincial transport will be necessary to address a mis-match between H_2 production and demand centers. Pipelines are the most cost-effective option for distances of 200−1500km.[22] Figure S12 shows all cost-effective pipelines between provincial capitals under the minimum-subsidy and the renewable subsidy scenarios. Our sensitivity analyses (Figures S13−S14) provide insights into the impact of hydrogen pipeline costs on potential network development.

We find that western Inner Mongolia, Hebei, and Fujian are primary electrolytic hydrogen export regions from both grid- and renewable-based electricity. Western Inner Mongolia has the most cost-competitive grid-based hydrogen in the minimum-subsidy scenario. Transporting this hydrogen to central provinces with higher electrolytic hydrogen costs will reduce national average $LCOH_2$ by 11−17% but will increase CO_{2e} emissions of electrolytic hydrogen by 12.3 kg CO_{2e}/kg H_2 in 2025, 5.9 kg CO_{2e}/kg H_2 in 2030 and 1.5 kg CO_{2e}/kg H_2 in 2040, respectively. This is because of the region's high GHG emissions from grid-based hydrogen and extensive leakage in long-distance transport. In the renewable subsidy scenario, Hebei, Fujian and western Inner Mongolia lead in cost-competitive renewables-based hydrogen using on-shore wind. Transporting hydrogen from Hebei, Fujian, and Inner Mongolia will reduce national average renewable-based $LCOH_2$ by 8−12% from 2025 to 2040 and will decrease CO_{2e} emissions of electrolytic renewable-based hydrogen by.

Trade-offs between $LCOH_2$ and GHG Emissions across Four Scenarios from 2025 to 2040. Electrolytic hydrogen from grid and renewable sources both with and without the use of pipelines for transport all have higher $LCOH_2$ from 2025 to 2040 than fossil-based hydrogen today (Figure 5). This is due to the projected high costs of electricity and capital costs of water electrolysis. Subsidies are effective at increasing the cost competitiveness of electrolytic hydrogen. Our results indicate that in 2025, national average subsidies of 2022\$1.7/kg H_2 can make electrolytic hydrogen cost-competitive (using the cheapest source of electricity for electrolytic hydrogen production in each province) with coal-based hydrogen (which currently costs ∼ 2022\$1.4/kg H_2) in most provinces.

To minimize carbon emissions, renewable-based subsidies are necessary and, on average, nationally must be 48% larger than grid-based subsidies. If grid- and renewable-based electrolytic hydrogen production are both subsidized at the same rate, it is likely that grid-based hydrogen, being cheaper in total, will scale up more quickly than renewable-based hydrogen. This will have the undesirable effect of increasing GHG emissions. From 2025

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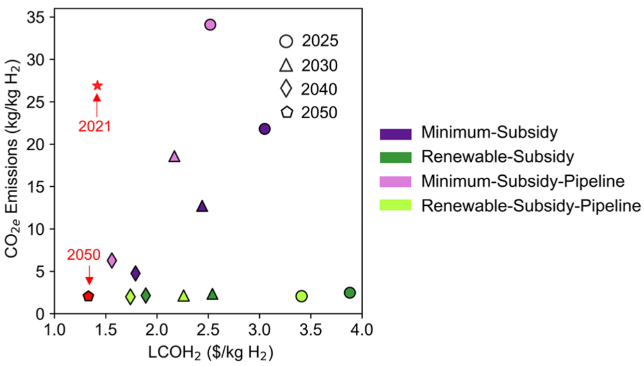

Figure 5. Comparison of $LCOH_2$, and CO_{2e} emissions using GWP20 under the minimum-subsidy and renewable-subsidy scenarios with and without pipeline transport of hydrogen. The red star and red pentagon indicate the national average $LCOH_2$ and CO_{2e} emissions of hydrogen production in 2021 and 2050, respectively. We assume a fully decarbonized grid in 2050, eliminating the difference between the minimum-subsidy and renewable-subsidy scenarios. (See the results using GWP100 in Figure S15.)

to 2040, the Renewable-subsidy scenario reduces life cycle GHG emissions by 55−88% with only a 6%−27% increase in $LCOH_2$, compared to the Minimum-subsidy scenario. Thus, higher subsidies of renewable-based electrolytic hydrogen result in dramatically lower costs of CO_{2e} mitigation per kg of H_2 produced.

Transporting grid-based electrolytic hydrogen with pipelines, rather than each province producing the hydrogen it needs, can reduce the national average $LCOH_2$ from grid electricity by 11−17%. However, transporting grid-based electrolytic hydrogen with pipelines increases life cycle GHG emissions by 32−56% due to hydrogen leakage and high emissions from provinces using coal intensive grid electricity. Thus, policymakers must be cautious in constructing hydrogen transport pipelines and only transport electrolytic hydrogen generated from renewable sources. For emission mitigation as the hydrogen industry scales-up, the optimal approach is to provide sufficient subsidies for renewable-based hydrogen production so that it becomes less costly than other forms of hydrogen production.

Hydrogen Leakage. Hydrogen is an indirect GHG. The oxidation of hydrogen increases concentrations of GHGs in both the troposphere and stratosphere. Molecular hydrogen in the atmosphere is oxidized by the hydroxyl radical (OH) to a hydrogen ion (H) and H_2O. As a result, in the troposphere, there is a decrease in available OH to react with methane, which results in longer methane (CH_4) lifetimes and a greater methane abundance. Furthermore, when molecular hydrogen is oxidized in the troposphere, it produces atomic hydrogen, which leads to a chain of reactions that increase the formation of tropospheric ozone. Meanwhile, in the stratosphere, hydrogen oxidation increases water vapor levels. This increases the infrared radiative capacity of the stratosphere and results in an overall warming effect on the climate.[10,11,36]

Hydrogen is a small volatile molecule that can easily leak from pipelines and transport vessels.[37,38] To estimate potential hydrogen leakage through the hydrogen life cycle of production, compression, storage, and transport, we conduct a sensitivity analysis of hydrogen leakage emissions based on prior studies.[2,39] SI Table S4 shows leakage rates for a sensitivity study reflecting best- and worst-case situations determined from literature estimates of total value chain emissions typically ranging from 1% to 10% and using estimates of potential future hydrogen demand in China. Possible cumulative future hydrogen leakage will vary greatly depending on the total demand and leakage rates.

We project that in 2050, hydrogen leakage could yield as little as 8 Mt CO_{2e} emissions based on a H_2 GWP_{100} of 11.6 with low leakage rates (1%) or as much as 246 Mt CO_{2e} with a GWP_{20} of 37.3 with high leakage rates (10%) (Table S4). These emissions represent between 0.1%−2.2% of China's total CO_{2e} emissions in 2020. This large range indicates the critical nature of minimizing H_2 (and CH_4) leakage to reduce its impact on climate.

Policy Implications. We quantify the trade-offs between subsidies and life cycle GHG emissions in accelerating electrolytic hydrogen development in China. We find that subsidies are essential to accelerate all types of electrolytic hydrogen development as electrolytic production remains more expensive than fossil-based hydrogen beyond 2040. However, subsidizing grid-based electrolytic hydrogen will increase CO_{2e} emissions compared to coal-based hydrogen, particularly in provinces that rely heavily on coal power. Subsidizing renewable-based hydrogen requires a small increase in subsidies and results in cost-effective CO_{2e} emission reductions compared to grid-based hydrogen.

In addition, we compare CO_{2e} emissions among various hydrogen production technologies and direct coal combustion. We find that the production of coal-based hydrogen emits 83% more CO_{2e} emissions than direct combustion of coal. Grid-based electrolytic hydrogen emits 63% more CO_{2e} in 2025 and 20% more CO_{2e} in 2030 than direct combustion of coal under an optimistic carbon emission assumption which leads to a rapid decarbonization of the power grid (SI Note S7). Under this optimistic scenario, after 2030, decarbonization of the power grid is sufficient to reduce CO_{2e} emissions from grid-based electrolytic hydrogen compared to direct coal combustion.

China currently encourages coal-based hydrogen production, which increases GHG emissions compared to emissions from direct coal combustion. For instance, Shanxi province has proposed an increase in coal-based hydrogen production without CCS in its hydrogen energy industry development plan for 2022−2035. Similar projects are underway in Inner Mongolia and Shaanxi provinces, with a project in Shaanxi already operational in September 2022. These hydrogen production plans focus on coal-based hydrogen production, with no mention of CCS and limited mention of electrolytic hydrogen production, but without any explicit discussion of renewable energy coupled hydrogen production. Our findings indicate that both coal-based and grid-based hydrogen use will increase CO_{2e} emissions compared to direct coal combustion.

However, electrolytic hydrogen production coupled with renewable energy can reduce GHG emissions by 83% relative to coal-based hydrogen, aligning with China's decarbonization goals. China's government now supports the development of concentrated renewable power generation in northern and northwestern provinces, such as Inner Mongolia and Hebei provinces, which are termed renewable energy bases. Co-locating renewable energy bases with hydrogen production provides an opportunity to reduce CO_{2e} emissions. The produced hydrogen also offers long-duration energy storage that can balance the intermittency of the renewable electricity supply and demand. Renewable-based hydrogen production costs are relatively low in "base" locations due to the high renewable energy resources available at these locations. This co-location strategy optimizes GHG mitigation and power grid

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stability, while also reducing renewable-based hydrogen production costs. However, renewable-based hydrogen remains more costly than grid-based hydrogen in the near term and coal-based hydrogen after 2040 due to high capital costs and additional battery expenses, making continuing subsidies critical for rapid deployment.

Low carbon hydrogen can also be produced from nuclear energy. However, the production of hydrogen from renewable energy offers additional advantages. For example, hydrogen is a form of long-term energy storage. It can be produced from excess renewable energy when available and stored for later use, particularly during peak electricity demand when renewables are in short supply. Moreover, compared to nuclear power plants, renewable energy sources offer greater location flexibility and can be located closer to hydrogen end-users. Therefore, our study focuses on low carbon hydrogen produced from renewables.

Subsidies for renewable-based hydrogen production are critical to achieve low carbon hydrogen production, use and associated GHG emission reductions. However, explicit subsidies for the production of hydrogen from renewable energy have not been implemented widely. For example, the US will increase hydrogen production subsidies as hydrogen is produced with lower GHG emissions. Subsidies begin at \$0.60/kg H_2 for 2.5−4 $kgCO_{2e}$/kg H_2 produced and increase with higher carbon capture rates or lower fossil energy penetration to the highest tier of \$3/kg H_2 when less than 0.45 kg CO_{2e}/kg H_2 is produced. However, this approach provides subsidies for hydrogen produced from fossil fuels with CCS and electrolytic production using nuclear power, as well as for hydrogen from renewable energy. Australia subsidizes electrolytic production costs to ensure total costs fall below AUD2/kg H_2 but does not currently have any requirements ensuring a limit on GHG emissions.

We find that a national subsidy of 2022\$2.5/kg H_2 would make renewable-based electrolytic hydrogen cost-competitive with coal-based hydrogen (2022\$1.4/kg H_2) in China by 2025. The national average subsidy required for renewable-based hydrogen in China is lower than the highest tier tax credit in the 2022 US Inflation Reduction Act (IRA) (2022\$3/kg H_2).

While our study focuses on China, there are broader lessons from our work that are applicable worldwide. These include the following: 1) consideration of the upstream and lifecycle emissions from fossil fuel and renewable energy production is critical when evaluating the efficacy of mitigation strategies; 2) financial subsidies can accelerate the production of electrolytic hydrogen but to reduce GHG emissions, subsidies should be limited to low-carbon electricity sources; and 3) trade-offs are involved in transporting hydrogen produced in renewable-rich locations to demand centers. Costs can be reduced, but increases in leakage emissions during transport can occur, thus leading to indirect climate warming impacts. Efforts to minimize leakage are crucial.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.3c03045.

Review of relevant water electrolysis literature and assumptions for costs of hydrogen pipelines; additional method details including hydrogen production technologies, assumptions for subsidy scenarios, estimates of levelized cost of hydrogen production, capital costs of renewable energy, and CO_2 emission estimates; additional results including Figures S4−S15 and Tables S4−S8 (PDF)

Source Data provides original data for Figures 1−5 (XLSX)

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Author Contributions

L.P., D.L.M., and G.H. conceived the idea of this project and designed the research with the assistance of Y.G. L.P. conducted experiments and analyzed the results with the assistance of Y.G., S.L., and D.L.M. L.P. and D.L.M. wrote the manuscript with input from all authors.

Notes

The authors declare no competing financial interest.

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