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A techno-economic, carbon intensity, and policy assessment of hydrogen production in the United States

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ABSTRACT

Comparing studies that involve techno-economic analyses (TEA) and life cycle assessments (LCA) for different hydrogen production technologies is challenging due to inconsistent assumptions across studies. Thus, this research develops a harmonized framework to assess seven hydrogen production pathways - water electrolysis, methane pyrolysis, biomass gasification, steam methane reforming, autothermal reforming, partial oxidation, and dry methane reforming, under consistent U.S.-specific techno-economic, carbon intensity (CI), and policy assumptions. Process models developed with Aspen Plus produce mass and energy balances, informing open-source TEA and cradle-to-gate CI estimates. Thermal conversion pathways produce hydrogen at \$0.8–\$3.9/kg, while electrolysis-based methods range from \$4.5–\$18.5/kg, contingent on both electrolyzer and the source of electricity used. Several low-carbon emitting pathways meet emerging clean hydrogen standards, but only some achieve cost parity with conventional hydrogen under current U.S. federal and state incentives. This framework enables consistent cross-technology comparison and supports informed decisions on hydrogen sourcing, including applications such as sustainable aviation fuel production or fuel cell electric vehicles.

1. Introduction

As the global energy market seeks to reduce its ecological footprint, clean hydrogen has become a key contender for decarbonization across various industries, including transportation, power generation, and heavy manufacturing [1–3]. Hydrogen is extensively utilized in the production of ammonia (NH_3) for fertilizers, in hydrotreatment processes within petroleum refineries, and as a clean reduction agent in metallurgical applications. New emerging applications include its direct use as fuel in transportation.

Hydrogen must be produced using low carbon emission sources to contribute meaningfully to decarbonization [4]. Several technologies can be employed for hydrogen production, each with specific attributes, including technological maturity, cost-effectiveness, feedstock type and availability, policy and regulatory support, and overall environmental impact. Hydrogen production methods span traditional processes such as coal/biomass gasification, steam methane reforming (SMR), autothermal reforming of methane (ATRM), and partial oxidation of methane (POM), to alternative emerging approaches including methane pyrolysis (MP), dry methane reforming (DMR), and high and low temperature water electrolysis (WE). An important metric for these technologies is the technology readiness level (TRL), ranging from 1 to 9 [5]. Fully commercialized technologies (without carbon capture), including gasification, SMR, POM, ATRM, and proton exchange membrane (PEM) electrolysis, reach a TRL of 9. Conversely, other methods such as MP (TRL 3–8), solid oxide electrolysis (SOE) (TRL 7), and DMR (TRL 4–6) face greater uncertainty regarding scalability and economic viability [5,6]. This diversity emphasize the ongoing need for sustained research and development to further enhance efficiency and reduce overall costs.

In addition to technological maturity, the carbon footprint for technologies is evaluated through carbon intensity (CI), which is influenced by factors such as the source of hydrogen (CH_4, H_2O, biomass), the electricity source used in production (non-renewable, solar, nuclear) [7], and additional inputs including catalysts and/or raw materials. Life cycle assessments (LCA), therefore, evaluate environmental impacts of hydrogen production technologies. CI offers comprehensive insights into

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potential environmental effects throughout the entire lifecycle of products or systems, encompassing stages from raw material extraction to manufacturing, product utilization, and end-of-life treatments such as disposal, incineration, or recycling [8].

Grey hydrogen, derived primarily from fossil fuels such as coal and natural gas [2,9,10], currently dominates global production at approximately 96%, with CI values ranging 7.5 to 13 kg $CO_2e/kg\ H_2$ [7]. In contrast, cleaner variants of hydrogen, such as green (renewable-powered electrolysis), blue (fossil with carbon capture), turquoise (MP powered by renewable electricity) [11], and pink (nuclear-powered electrolysis) can result in CI values between 0.3 and 4 kg $CO_2e/kg\ H_2$ [7,11,12]. However, differing definitions and CI thresholds complicate standardization efforts [4,13].

This definitional ambiguity extends into policy frameworks. In the U.S., the Infrastructure Investment and Jobs Act and the U.S. Department of Energy (DOE) guidelines had defined clean hydrogen using CI thresholds from ≤2 kg $CO_2e/kg\ H_2$ [12,14] (or ≤ 4 kg $CO_2e/kg\ H_2$ on a cradle-to-gate basis), aligning with the 2022 Inflation Reduction Act (IRA) incentives [15]. Europe has set a threshold at 3 kg $CO_2e/kg\ H_2$, while the U.K. has adopted 2.4 kg $CO_2e/kg\ H_2$ [15]. These variations significantly influence domestic and international hydrogen strategies [16,17].

Recognizing the strategic importance of hydrogen, countries worldwide have launched national hydrogen strategies. The U.S. currently produces and uses roughly 10 million t/yr of hydrogen, with nearly all of it generated through SMR [2]. By incorporating alternative production methods and leveraging domestic resources such as renewable energy, biomass, and waste streams, output production could increase to 22–42 million t/yr [18,19]. The DOE's Hydrogen Shot initiative set ambitious cost-reduction targets for WE, aiming for $2/kg by 2026 and $1/kg by 2031 [2,20]. Similar efforts are emerging worldwide: Japan targets zero-carbon hydrogen by 2040 [21], Australia seeks affordable (≤$2/kg), exportable hydrogen [22], and the European Union has likewise advanced its deployment plants, targeting the installation of 40 GW of electrolyzer capacity capable of producing 10 million t of renewable hydrogen by 2030 [23]. Recent policy initiatives in India [24] and China [25] further illustrate the accelerating global push toward large-scale clean hydrogen development [26].

To meet these ambitious targets, methods such as SMR with carbon capture, utilization, and storage (CCUS) or MP are being explored [2]. However, CCUS efficiency varies widely (50–98%) [27–30] raising questions about economic trade-offs and residual emissions. This stresses the importance of balancing cost-effectiveness with emission reductions, an essential factor for the competitiveness of low-carbon hydrogen [31].

From an economic standpoint, transitioning from current production technologies is challenging. Grey hydrogen remains the cheapest ($0.5–$2/kg), while green hydrogen can vary in cost from $4 to more than $12/kg [4,13,32,33]. Bridging this price gap, often referred to as the "green premium," may require monetizing CI benefits [3,34,35]. Policy instruments are crucial in this regard. For example, the European Hydrogen Bank's 2023 auction awarded bids between €0.37 and €0.48/kg, well below the €4.5/kg maximum subsidy [36,37]. In the U.S., the IRA (2022) offered CI-based tax credits (45V) ranging from $0.6 to $3/kg [38], and state programs like California's Low Carbon Fuel Standard (LCFS) provide incentives for low-CI hydrogen [39].

Within this fractured and evolving policy and economic landscape, stakeholders rely on techno-economic analysis (TEA) and CI scores to make informed decisions [40,41]. Nevertheless, differences in methodological assumptions across technologies, financing, and operations lead to inconsistent comparisons for cost estimates. Standardized TEAs using harmonized, location-specific parameters are therefore essential for cross-comparison of hydrogen production pathways.

To address these challenges, this study develops a fully open-source, harmonized, multi-technology assessment of seven major hydrogen production pathways using consistent U.S.-specific techno-economic and policy assumptions, standardized mass and energy balances, aligned financial parameters, and uniform LCA boundaries, while accounting for the TRL limitations of each pathway. This framework enables (1) calculation of the minimum selling price of hydrogen (MSPH), (2) estimation of CI with and without CCUS, (3) determination of associated abatement costs, and (4) evaluation of the capacity of U.S. policy incentives to close existing price gaps. By harmonizing all underlying assumptions, the analysis isolates performance differences that arise from the technologies themselves, rather than from methodological inconsistency, providing a transparent, comparable basis for identifying cost drivers, decarbonization opportunities, and technology-specific research needs across the hydrogen spectrum.

2. Methodology

Seven production technologies were modeled using Aspen Plus V12 to obtain mass and energy balances for each process: (1) WE; (2) MP, with carbon black or carbon nanotubes (CNTs) as a co-product; (3) SMR; (4) ATRM; (5) POM; (6) DMR; and (7) biomass gasification (BG) operated at high and low pressure using forest residues, corn stover, or municipal solid waste (MSW) as feedstock. Each model was validated against literature sources, see Supplementary Material 1. The resulting mass and energy flows from the modeling were used as input parameters in the TEA to estimate the operational costs for calculation of the MSPH, their CI and the CO_2 abatement cost. Fig. 1 shows the methodology followed to estimate the MSPH, defined as the mill-gate price required to achieve a net present value of zero with the assumed discount rate at the end of the facility life.

2.1. Mass and energy balance

The mass and energy balances developed in this study were generated through independent Aspen Plus simulation for each hydrogen production pathway. Operating parameters reflect the underlying chemistry and engineering design, including the $C/CH_4/H_2O/CO_2/O_2$ ratios selected to maximize hydrogen yield. To ensure comparability across technologies, all simulations were conducted under harmonized boundary conditions. Reforming pathways, for example, were modeled at consistent temperatures and pressures, and uniform pressure–temperature settings were applied to pressure swing adsorption (PSA) purification and CCUS units. Each open-source TEA provides a detailed process flow diagram describing operational parameters and reactions sets [42–48].

This harmonized approach ensures that differences in TEA and LCA results stem from the technologies themselves rather than from inconsistent modeling assumptions. Aligning operating conditions is essential because capital expenditures (CAPEX) and operational expenditures (OPEX) are highly sensitive to temperature and pressure, which directly influence compressor size, heat-exchange requirements, and overall energy demand. Standardized assumptions therefore provide a fair basis for cross-technology comparison.

Furthermore, the mass and energy balances obtained using Aspen Plus were cross-validated with published literature to confirm their plausibility. These balances serve as inputs to the TEA and LCA, including utilities like steam, cooling water, natural gas for process heat, and associated CO_2 emissions. Table S1–S2 in the Supplementary Material 1 provide summaries of these mass flows.

2.2. Techno-economic analysis

The selected TEA methodology calculates total capital investment by applying ratio factors to inside battery limit equipment costs (see boundary definition in Fig. S1) [49,50] (also known as Lang factors) with an estimated accuracy of ±20-30%, all normalized to 2021 U S. dollars [51–53]. Capital costs are adapted from publications detailed in the open-source models [42–48]. Aspen's mass and energy balance data

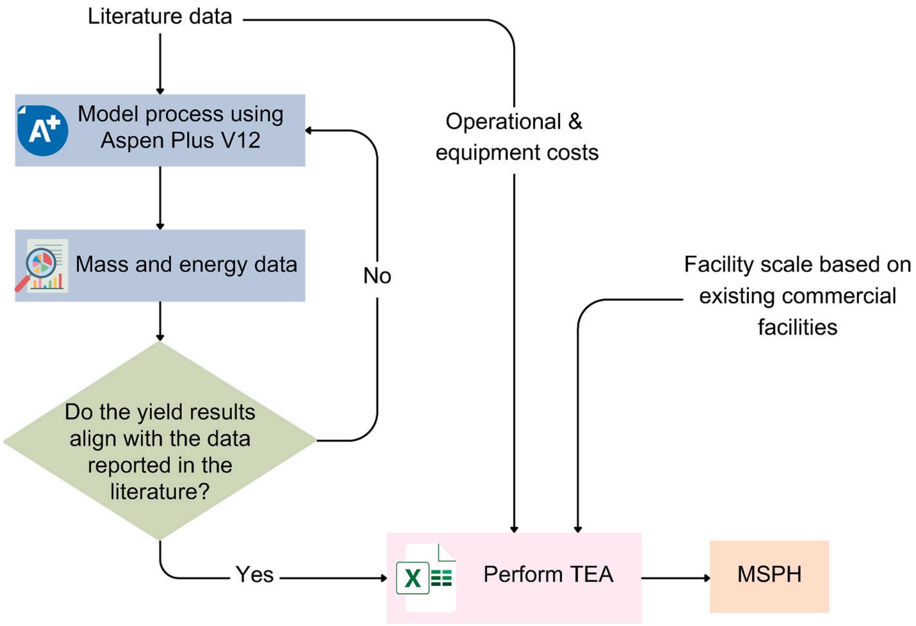


Fig. 1. Methodology used to determine mass and energy balances and calculate the MSPH for each technology.

were integrated into the TEA to quantify operational costs. The MSPH for each scenario is calculated with a baseline real cost of equity of 10%. The weighted average cost of capital was chosen for the economic perspective to ensure revenue generation is sufficient to cover costs associated with funding from shareholders and banks, while maintaining a constant capital structure over time. Harmonized financial assumptions and operational costs are summarized in Supplementary Material 1 Table S3, with full details in the open-source models [42–48].

The hydrogen yield for each conversion process was determined based on the operational parameters specified in the corresponding process flow diagram (PFD) within each TEA model [42–48]. Facility scale, defined by its annual feedstock capacity (t/yr), was selected for each conversion technology based on the largest size of industrial plants currently in operation [30]. This approach ensures the evaluation aligns with real-world conditions and yields a realistic view of capital and operating costs. However, no commercial DMR plants were identified as being in operation [54]. Therefore, for this technology, the natural gas input for SMR was used as an approximation.

Technology maturity also influences the assumptions and uncertainty levels embedded in each TEA. Therefore, SMR, ATRM, POM, BG, SOE, and MP with carbon black production are considered mature and proven technologies (nth–plant systems) with established commercial deployment [55]. In contrast, DMR, CNTs production via MP, and alkaline water electrolysis (AWE)/PEM electrolysis remain at the pioneer stage, lacking large-scale implementation and replication. TEAs of these early-stage technologies can either assume a mature-plant scenario (nth-plant) or explicitly incorporate the higher uncertainty associated with first-of-a-kind systems. In this study, the pioneer analysis captures elevated financial risks through the application of a cost growth factor (CGF), which adjusts capital costs to reflect scale-up challenges and delayed production ramp-up typical of emerging technologies (DMR, AWE, PEM, and MP producing H_2 and CNTs). A CGF for each novel technology was calculated using an empirical methodology that estimates the impact of process novelty, complexity, the presence of impurities, project definition and inclusivity of the model on capital costs for pioneer plants [55].

2.3. Scenarios

The following scenarios were analyzed to assess how parameter variations influence the MSPH. Each scenario was designed to isolate and quantify the effects of key factors on overall production costs, providing a clearer understanding of their individual and combined impact.

2.3.1. Baseline settings

The baseline scenario applies all financial assumptions summarized in Table S3 of Supplementary Material 1 and the operational cost values listed in Table 1. In the MP pathway, the baseline co-product is carbon black, and natural gas is used as the heat source for the pyrolyzer. All

Table 1
Factors included in the sensitivity analysis.

Operational cost	Baseline	Ref.
Municipal solid waste ($/t)[a]	13	[57]
Corn stover ($/t)[a]	125	[57,58]
Forest residues ($/t)[a]	180	[57,59]
NG ($/MMBtu)	5.09	[60]
Electricity ($/kWh)	0.072	[61]
Cooling water ($/kg)	1.94×10^{-5}	[62]
Distilled water ($/kg)[b]	2.85	[63]
Waste water ($/m^3)	3.56	[63]
KOH ($/kg)	3.60	[64]
Steam ($/kg)	0.010	[65]
Deionized water ($/kg)[b]	0.014	[66]
Nitrogen ($/kg)	0.41	[64]
Catalyst Fe/Al_2O_3 for MP($/kg)	8	[67]
Copper-zinc based catalyst for water-gas shift (WGS) ($/kg)	17.64	[68]
Nitric acid ($/kg)	0.22	[69]
Carbon Dioxide for DMR ($/t)	27	[56]
Co-product selling price	**Baseline**	**Baseline Ref.**
Oxygen ($/kg)	0.12	[70]
Nitrogen ($/L)	0.13	[71,72]
Carbon black ($/kg)	1.00	[67]
CNTs ($/kg)	35	[73]

[a] Includes pre-processing cost (drying/milling and the associated dry-matter loss (~9%)) obtained using the FT feedstock pre-processing TEA-v2.1. Biomass preprocessing is co-located with conversion.

[b] High-purity water is highly recommended to maintain catalyst efficiency and reactor longevity in the WGS reaction.

technologies were evaluated under a nth plant framework, except for AWE, PEM, DMR, MP (with CNTs as co-product) for which a CGF of 0.57, 0.55, 0.74, 0.43 respectively, was applied. In the baseline case of WE, the electricity source selected is onshore wind (Table 2). For DMR, CO_2 is considered an OPEX at 27 $/t [56].

2.3.2. *Sensitivity analysis*

We evaluated the influence of operational costs and co-product revenues on the MSPH using a one-at-a-time (OAT) sensitivity approach. Starting from the baseline TEA case, each parameter was varied within historically informed bands derived from U.S. annual data (2012–2022). Specifically, electricity (±15%) [75], biomass (based on average nominal price change) (±30%) [76,77], natural gas (±20%) [78], water (±5%) [79], carbon black (±10%) [80], CNTs (±30%) [67,73,81], wholesale oxygen (±20%) [82], and wholesale nitrogen (±20%) [83], based on observed year-to-year variability in the U.S Bureau of Labor Statistics Producer Price Index and the U.S Energy Information Administration (EIA) statistics. For raw materials lacking sufficient historical data, a ±20% range was assumed. To quantify the importance of CAPEX, the range tested was tied to the estimated modeling methodology accuracy for ratio factor based TEAs of ±30 % as opposed to using data over the above stated timeline [49]. Only a single variable was tested at a time, holding all other inputs constant. The resulting changes in MSPH were converted to elasticities (Equation (1)) to provide a unit-free ranking of cost drivers.

$$E = \frac{\Delta MSPH / MSPH_{baseline}}{\Delta X / X_{baseline}} \qquad \text{Equation 1}$$

Where $\Delta MSPH$ is the change in the MSPH when the input is perturbed, $MSPH_{baseline}$ is the baseline value of MSPH, and $\Delta X / X_{baseline}$ is the relative change in the input.

After completing the OAT, the two most influential parameters from the OAT stage were then tested together in a three-level factorial grid to assess potential interaction effects. All analyses were automated via a Python-Excel workflow to ensure consistent recalculation and reproducibility.

2.3.3. *Carbon capture, utilization and storage*

All the TEAs, except for WE, incorporate an option for CCUS, assuming a CO_2 capture efficiency of 90% [27–29]. For context, the H2A-Lite model assumes a capture efficiency of 94.5% [18] while the Clean Hydrogen Production Standard (CHPS) specifies 95% [15]. In accordance with national greenhouse gas (GHG) inventory conventions, captured biogenic CO_2 from biomass gasification is treated equivalently to CO_2 captured from fossil-based processes. Following capture, CO_2 is compressed to its supercritical state (>74 bar and ~31 °C) for transportation and storage. A pipeline transportation and storage cost of $10/t CO_2 is applied, which is considered a reasonable estimate for the U.S [84]. Both CAPEX (e.g., compressors) and OPEX (e.g., electricity consumption) associated with CCUS integration are explicitly incorporated into the TEAs.

Table 2
Electricity source and cost.

Electricity source	Cost ($/kWh)	Ref.
Hydroelectric	0.081	74
Grid	0.072	61
Solar Thermal	0.225	74
Solar PV	0.081	74
Onshore wind	0.064	74
Offshore wind	0.178	74
Biomass	0.124	74
Geothermal	0.053	74
Advanced Nuclear	0.121	74
Coal 90% CCUS	0.150	74

2.4. *Carbon intensity*

This study explicitly focuses on cradle-to-gate emissions, representing the primary environmental impacts directly related to hydrogen production processes [30,85]. Within this defined boundary, spanning raw material extraction, processing, and production activities, the study considers three primary sources of CO_2 emissions: (1) CO_2 released following PSA separation, typically generated during the WGS reaction (Section 1.4 in the Supplementary Material 1); (2) CO_2 emissions associated with heat supply, resulting from natural gas combustion, and (3) upstream GHG emissions, (CO_2, CH_4, and N_2O), originated from the earlier stages of raw material production and processing.

The CI calculations follow the approach outlined by McNaul et al., [30] using 100-year global warming potentials (GWPs) from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) [86]. The resulting CI values are expressed as kilograms of CO_2-equivalent (CO_2e) per kilogram of gaseous H_2 (>99.9%-vol purity, compressed at 34 bar) produced at the facility gate. Liquified H_2 has a higher CI due to the additional energy required for liquefaction; for SMR-derived H_2, CI values of 137.92 g CO_2e/MJ (well-to-gate) and 150 g CO_2e/MJ (well-to-wheels) have been reported [87,88].

Emission factors based on the U.S. national energy mix, which includes coal, wind, solar, and natural gas, were used to quantify upstream emissions. Over the past decade, the share of renewable energy in U.S. electricity has increased significantly, from 15.3% in 2016 to 25.7% in 2025 [89], primarily due to policy initiatives and expanded deployment of renewable energy sources. This has resulted in a decrease in the CI of U.S. electricity by approximately 20–30% [89]. The decreasing trend is expected to continue as renewables and nuclear power increasingly contribute to the national energy portfolio, aligning with the U.S.' goal of achieving carbon neutrality by 2050 [90]. Reflecting this energy transition and maintaining consistency with the economic assumptions of current TEAs, the 2021 electricity emission factor was selected instead of a long-term average.

For WE, electricity costs were evaluated for multiple sources to assess discrete technology-driven impacts (Table 2). Additionally, each electricity source has an emission factor, (Table 3), which is included in the CI estimations for this technology. The emission factors were derived from the U.S EIA data [91] and the U.S. Environmental Protection

Table 3
U.S carbon emission factors.

Parameter	Value	Ref.
Electricity mix Carbon Emission Factor (kg CO_2e/kWh)[a]	0.40	[92]
Electricity from Coal Carbon Emission Factor (kg CO_2e/kWh)[a]	1.07	[92]
Electricity from Biomass Carbon Emission Factor (kg CO_2e/kWh)	0.03	[92]
Electricity from Hydropower Carbon Emission Factor (kg CO_2e/kWh)	0.02	[92]
Electricity from Nuclear Carbon Emission Factor (kg CO_2e/kWh)	0.00	[92]
Electricity from Solar PV Carbon Emission Factor (kg CO_2e/kWh)	0.00	[92]
Electricity from Solar Thermal Carbon Emission Factor (kg CO_2e/kWh)	0.05	[92]
Electricity from Geothermal Carbon Emission Factor (kg CO_2e/kWh)	0.05	[92]
Electricity from Wind Carbon Emission Factor (kg CO_2e/kWh)	0.00	[92]
KOH Carbon Emission Factor (kg CO_2e/kg KOH)	1.94[b]	
Nitrogen Carbon Emission Factor (kg CO_2e/kg N_2)	0.43[b]	
Natural Gas Extraction Carbon Emission Factor (kg CO_2e/kg NG)[c]	0.94	[93]
Copper-zinc based catalyst Emission Factor (kg CO_2e/kg)	8.00	[94]
Zeolite packing Emission Factor (kg CO_2e/kg)	4.19	[94]
Fe/Al_2O_3 based catalyst Carbon Emission Factor (kg CO_2e/kg)[d]	2.20	[63,95]

[a] Energy mix (coal, wind, solar, and Natural Gas).

[b] Aspen Plus V12.

[c] Includes production, gathering & boosting, processing, transmission, storage, pipeline, and distribution (CO2, CH4, and N2O).

[d] Assuming 10% loading.

Agency (EPA) [92].

Emissions associated with land-use changes (e.g., land clearing) and dedicated agricultural inputs such as fertilizers, irrigation, and pesticides were excluded because the biomass feedstocks considered – corn stover, forest residues, and MSW – are classified as waste materials. Biomass gasification and subsequent WGS reactions produce CO_2 that is considered biogenic and is therefore assumed to be net-zero within the modeling boundary, consistent with national GHG inventory reporting conventions [74,96], in which biomass-combustion CO_2 is reported separately and net stock changes are accounted in the land sector. However, this accounting convention does not imply universal carbon neutrality, as the net atmospheric impact depends on factors such as feedstock source, carbon-stock dynamics, counterfactual fate, and temporal effects (carbon debt and payback). Consequently, emission associated with biomass gasification in this study are limited to those arising from the extraction and production of non-biogenic raw materials [97, 98].

Additional upstream inputs considered in the analysis include copper-zinc-based catalysts, Fe/Al_2O_3-based catalysts, zeolite packing, KOH, nitrogen, and natural gas extraction. A detailed breakdown of the emission factors for these materials and processes is presented in Table 3.

Emissions from natural gas combustion were already accounted for as part of the heat supply. Therefore, the total CO_2 emissions from each process are calculated by summing all the aforementioned sources. Finally, the CI is calculated according to Equation (2):

$$CI = \frac{kg\ CO_2|_{process} + kg\ CO_2|_{energy\ supply} + kg\ CO_2e|_{upstream\ emissions}}{kg\ H_2\ Produced} \qquad \text{Equation 2}$$

2.5. Abatement cost

Selecting the lowest-cost hydrogen production technology based solely on the MSPH provides a valuable yet incomplete assessment. While a MSPH ranking clearly identifies cost advantages, it fails to consider the broader environmental services offered by each technology. These services encompass natural processes and functions that enhance human well-being, including reductions in GHG emissions, waste minimization, job creation, and carbon sequestration [99].

In this broader context, the “green premium” concept is particularly insightful. It refers to the cost difference between a conventional product and its lower carbon intensity alternative. For instance, in the case of hydrogen, the green premium is the gap between the minimum selling price of cleaner hydrogen and the minimum selling price of conventional “grey” hydrogen produced through SMR of natural gas [100,101].

Abatement cost quantifies the expense of avoiding one ton of CO_2e emissions compared to a standard process [102]. By comparing abatement costs across technologies, it becomes possible to identify the most cost-effective pathways for emission reduction. In this study, the abatement cost is calculated relative to hydrogen produced from natural gas via SMR, as shown in Equation (3):

$$Abatement\ Cost\left(\frac{\$}{t\ CO_2e}\right) = \frac{MSPH_{novel\ technology} - MSPH_{SMR}}{CI_{SMR} - CI_{novel\ technology}} \qquad \text{Equation 3}$$

2.6. U.S. Hydrogen policy support

U.S. policy support for hydrogen is available from both federal and state programs. Stacking monetary incentives for all applicable jurisdictions is critical for bridging the green premium. In this work, available policy support will be evaluated in two ways: (1) the ability to meet price parity with traditional hydrogen as shown through a reduced MSPH, and (2) the remaining abatement cost, or marginal abatement cost, required to reach financial viability.

In 2022, the U.S. IRA [38] introduced two tax credits applicable to renewable hydrogen production that were then updated in July of 2025 with the passage of the One Big Beautiful Bill Act (OBBBA) [103]. Specifically, the credit for clean hydrogen production and the credit for the sequestration of CO_2, denoted 45V and 45Q, respectively. These Acts stipulate conditions that influence the value and ability to claim the credits; for this analysis, it was assumed that wage and apprenticeship requirements were met and that there are no restrictions from foreign entity interests. These two tax credits cannot be combined; thus, each will be looked at individually and compared for the applicable scenarios.

Production of hydrogen is directly supported by 45V which provides eligible producers with ten years of tax credits if the facility is under construction by January 1, 2028, a deadline that the OBBBA moved five years earlier than the original IRA legislation. While the impact of this will not be seen in reduced values for producers that are able to start construction by the end of 2027, it is likely that it will limit the number of facilities able to claim this credit. A sliding scale is set for the value of 45V based on the CI value of the hydrogen produced. The value is \$0.6/kg H_2 for CI values between 2.5 and 4 kg CO_2/kg H_2, \$0.75/kg H_2 for a CI of 1.5-2.5 kg CO_2/kg H_2, \$1/kg H_2 for a CI of 0.45-1.5 kg CO_2/kg H_2, and \$3/kg H_2 for a CI less than 0.45 kg CO_2/kg H_2. Depending on the particulars of the hydrogen production, this U.S. policy could potentially provide substantial funds [38]. This tax credit is governed by what has be termed the “three pillars”: additionality (new clean electricity or siting in a state with policies that have acceptable emission limits/goals), local electricity production (within a single U.S. Department of Energy “National Transmission Needs Study” region or with documented transmission rights), and temporal matching (electricity produced in the same hour as the hydrogen) [104]. While these are all challenging and temporal matching creates an hourly credit price based on the electricity used, in this work it was assumed that all three pillars were met. This may overestimate the weighted average credit value for WE pathways that use a higher CI electricity when renewable electricity is not available.

A facility that employs CCUS, could choose to earn 45Q credits if they are unable to earn 45V credits or if the overall economics are superior [38,103]. Eligibility for 45Q for a hydrogen production facility starts when a minimum of 12,500 t CO_2 is collected annually and either used in or stored following an approved method. If construction starts before 2033, 45Q supports CCUS \$85/t CO_2 [38]. It was assumed that all CO_2 stored meets the requirements of this policy.

In California, the state's LCFS is available for hydrogen if the CI is below the annual target and is used in fuel cell electric vehicles (FCEV), the installation of zero-emission-vehicle refueling infrastructure, or in the production of renewable fuels [105–107]. This work assumes that the hydrogen produced is used directly in FCEVs. Credits are generated when a fuel is below the annual target and are issued for each t CO_2e not emitted. For fuels with CIs above the target, it was assumed that the hydrogen was sold into another market to avoid paying into LCFS. LCFS is a market value program, which means that the value of each credit varies with the market demand for credits. To account for this uncertainty, median, minimum, and maximum value scenarios are completed using historical prices from 2022 to 2024 and comparing to the 2026 CI target, a 15% reduction from the baseline [108]. LCFS credits can be stacked with federal tax credits.

While LCFS supports the use of lower CI hydrogen, the demand for hydrogen that will be used according to LCFS guidelines is likely to be limited in the near term. The current estimated hydrogen fueling station capacity varies as the stations are intermittently unavailable but has been estimated as 16,000–17,000 t/yr [109,110]. Announced new stations could bring this value up to nearly 40,000 by the end of 2029, a value that is expected to outpace demand [109,111]. Even if demand reaches 40,000 t/yr, it is unlikely to support the construction of renewable hydrogen facilities. Additional capacity could be used in the production of fuels or other processes where the use of higher cost cleaner hydrogen is viable. However, focusing on fueling FCEVs, low demand forecasts are compounded by the current use of grey hydrogen, the price of which is listed as a primary deterrent to consumers purchasing hydrogen vehicles [109]. To account for potential LCFS volume limitations, the policy analysis will be presented as federal support only and federal support plus California's LCFS.

3. Results and discussion

Employing the TEA, CI, and abatement cost methodologies enables comparison of economic viability, relative cost-effectiveness of carbon dioxide reduction, and the capacity of existing policy support to absorb the green premium. The subsequent section provides detailed results for various scenarios.

3.1. Baseline TEA

Baseline MSPH values for each technology were compared against those reported in the literature. Fig. 2a shows a box plot of hydrogen prices from previous studies (detailed in Supplementary Material 1, Table S4) adjusted to 2021 U S. dollars, while Fig. 2b presents the corresponding facility scales in tons of hydrogen per year, with scatter points representing results from this work.

Price dispersion across studies mostly tracks local energy and natural gas costs (Fig. 2a). MP and methane reforming are especially volatile with natural-gas prices, which drives much of the spread reported for these routes. Under consistent assumptions (same location, financials, and methods), our harmonized TEAs estimated a MSPH between \$0.8 and \$3.9/kg H_2 (without WE). WE is far more sensitive to electrolyzer type and electricity source at \$4.5–\$18.5/kg H_2.

Overall, MSPH values from this study fall within literature ranges but generally lean toward the lower end, a trend likely driven by the larger facility scales modeled here (Fig. 2b). The values reported in the literature for facility-scale in ATRM and POM are significantly smaller than those of current operational or under construction plants [30]. This indicates that most literature data correspond to early conceptual or pilot-scale analyses rather than the industrial-scale implementations now being deployed. As a result, those studies do not capture the full large-scale potential of these technologies [112]. A similar situation applies to WE, many reported cases correspond to small distributed systems or early pilot installations, while several hundred-megawatt electrolyzers (SOE) are now under construction or operation worldwide [113].

Furthermore, as illustrated in Fig. 2b, at industrial level, facility scale differences are significant. For example, SMR plants operated by Air Liquide and Air Products [30] are nearly 8.5 times smaller than ATRM plants (in natural gas input), contributing to SMR's elevated $MSPH_{baseline}$ despite its high hydrogen yield. The absence of co-product revenue further diminishes SMR's economic advantage, but it also reduces its dependence on other markets. In this work, SMR's $MSPH_{baseline}$ is \$1.3/kg H_2, but matching the ATRM/POM scale (9000 t/day natural gas input) would reduce it to \$1.1/kg H_2. Conversely, if co-product revenue is not considered in ATRM, the MSPH would be \$1.2/kg H_2.

Table 4 benchmarks the MSPH estimated in this study against results from H2A-Lite, one of the most recent publicly available hydrogen production models developed by the National Laboratory of the Rockies with U.S. DOE support. The comparison is limited to technologies available within the H2A-Lite framework; nevertheless, the MSPH values obtained here generally fall within the range reported by the tool.

Small deviations between the two sets of results are expected and primarily reflect differences in financial assumptions, plant scales, process configurations, and boundary conditions. Importantly, despite these methodological differences, the close agreement across technologies demonstrates that the harmonized framework developed in this work provides representative MSPH estimates.

3.2. Sensitivity analysis

Sensitivity analysis provides critical insight into which parameters most strongly influence the MSPH across technologies. By normalizing results through elasticity, factors with different units and scales can be directly compared. A high elasticity indicates that the MSPH is strongly influenced by that parameter, whereas a low elasticity signifies weak dependance, even if the parameter's absolute value or cost contribution is large. Identifying the most influential parameters and examining their interactions highlights whether factors combine additively, multiplicatively, or nonlinearly, offering valuable guidance for prioritizing cost-reduction strategies and evaluating the robustness of each hydrogen production pathway. In the following section, a detailed sensitivity

Table 4
Comparison of the baseline scenario modeled in this study with the estimates provided by H2A-Lite.

Technology	This work	H2A-Lite [18]
SMR	1.3	1.2
Biomass gasification	2.5	2.5
SOE-grid	5.5	4.4
PEM-solar	10.7	10.4
PEM-wind	9.7	6.4
AWE-solar	9.6	8.6
AWE-wind	8.7	5.4

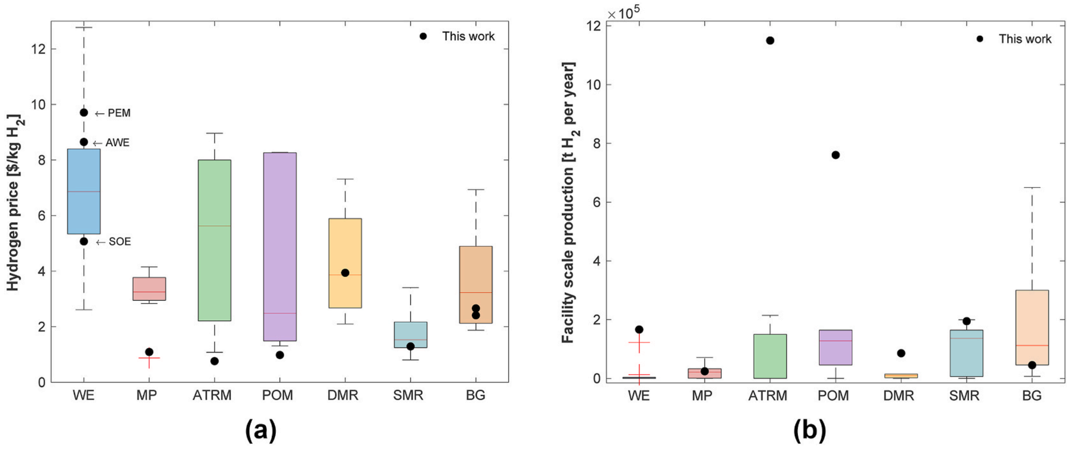


Fig. 2. a) Box plot distribution of hydrogen price, and b) Box plot distribution of facility scale production. Red lines are medians, red points (+) are outliers from the average value. MSW used as feedstock for BG. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

analysis for each technology is presented.

3.2.1. Water electrolysis

For AWE and PEM, the primary factor influencing the MSPH is the cost of the stack (electrolyzer), as it requires replacement every 10 years. This is followed by the electricity price and the revenue generated from the co-product (O_2). In contrast, for SOE the substantially lower stack cost, roughly half of AWE/PEM, drops its influence to second place, leaving electricity as the dominant factor (Fig. 3a). Additionally, comparable changes in water and steam have minimal effect. Practically, this means securing price certainty for power, managing stack costs (especially for AWE and PEM), and establishing a credible co-product monetization strategy matter far more than squeezing small savings from utilities.

The two-way sensitivity analysis between electricity price and stack cost (Fig. 3b) illustrates how these two factors interact to shape MSPH. The surface declines sharply along the electricity-price axis, indicating that MSPH is primarily driven by the cost of power: cheaper electricity yields lower MSPH. In contrast, stack cost acts more like a vertical shift, reducing stack cost lowers the entire surface uniformly, while higher stack cost raises it, meaning it influences the baseline cost but does not change the slope of the response dramatically as electricity does. When comparing electrolyzer technologies, SOE consistently produces the lowest MSPH for any given pair of assumptions, AWE performs intermediate values, and PEM remain the most expensive unless electricity prices are very low or O_2 revenues are high. Importantly, access to low-cost (≤ 0.08 \$/kWh), low-carbon electricity significantly increases the competitiveness of all three electrolyzer types (Fig. 3c).

The economic viability of WE is not determined solely by hydrogen production costs, but also by the capacity of existing markets to absorb or valorize the co-produced oxygen. By 2024, the U.S. accounted for roughly 22% of global oxygen production capacity, producing approximately 20 million tons of industrial-grade oxygen per year through conventional air separation units (ASUs) [114]. This production volume already satisfies the demand of major oxygen-consuming sectors, such as steelmaking, oil refining, and chemical processing, which collectively account for about 70% of total U.S. oxygen use [115].

When scaled to the capacity considered in this study, the oxygen generated by WE corresponds to 3% of the total U.S. industrial oxygen market per year (0.8 million t/yr). While this fraction may appear modest at small scales, widespread deployment of electrolyzers would rapidly approach or even exceed existing market demand, risking saturation. Therefore, the long-term potential of WE lies in its integration with existing processes that depend on oxygen from ASUs, such as ATRM, POM, and BG. In such hybrid setups, the co-produced oxygen can be directly utilized on-site, reducing reliance on external ASUs and enhancing overall system efficiency. Additionally, both the sensible heat released during syngas cooling and the heating value of waste gases can be used to provide heat for high-temperature electrolysis [116].

3.2.2. Methane pyrolysis

For MP, the sensitivity analysis demonstrates that the MSPH is strongly leveraged to co-product revenues, the sale of carbon black or CNTs exerting the largest influence on economic performance (Fig. 4). This is particularly critical in MP, which generates 3 kg of carbon for every 1 kg of H_2, making carbon sales a dominant contributor to overall revenues.

A change in co-product revenue (carbon black) produces a larger swing in MSPH than even a ±20% fluctuation in second most influential variable, natural gas, underscoring the critical importance of valorization pathways for carbon black (Fig. 4a). After natural gas, the capital cost of the pyrolyzer and the cost of catalysts in the pyrolyzer are the next most controlling items.

Electricity exerts a moderate influence, while water costs are negligible. The two-way interaction analysis between natural gas and carbon black sales reveals a dual-axis risk, MSPH remains competitive ($<$\$1.2/kg H_2) only under conditions of both low natural gas prices and strong co-product revenues, while unfavorable combinations push costs above \$1.4–1.6/kg H_2 (prices that are still competitive with SMR). Exxon and BASF have partnered to expand the development of MP by building a demonstration facility in Baytown, Texas, designed to produce 2000 tons of H_2 and 6000 tons of solid carbon annually [117].

Exploring the potential to upgrade carbon black into higher-value CNTs offers a pathway to enhance revenues and improve competitiveness of catalytic MP [11]. When CNTs are treated as co-product and hydrogen remains as the primary product (Fig. 4b), the two-way analysis reveals extreme variability in the MSPH. Under favorable conditions, characterized by strong CNT market prices and low nitric acid cost, the MSPH can fall below \$1/kg H_2. However, when CNTs revenues decline or raw material costs increase, the MSPH rapidly escalates to uncompetitive levels exceeding \$10/kg H_2. This widespread reflects the fact that MP produces three times more solid carbon than hydrogen, causing CNT revenue assumptions to dominate the overall economics.

To better isolate the economic viability of CNT production, the analysis is inverted in Fig. 4c by treating CNTs as the primary product and H_2 as low-value co-product with an assumed selling price of \$1/kg H_2. Under this framing, the minimum selling price of CNTs remains under a range between \$30.5–40.1/kg, below current market values (Table 5). This result suggests that producing CNTs from MP could be economically viable if CNTs, rather than hydrogen, are the primary value stream. Furthermore, the assumption that hydrogen can be sold in the market at \$1/kg H_2 is more realistic, and the impact of co-product sales is less significant in this scenario (Fig. 4c). This allows for the possibility of selling hydrogen at lower market prices if necessary.

These results illustrate both the opportunity and the risk associated with CNT valorization. While the potential economic upside is significant, project viability is sensitive to CNT market prices and to the technological feasibility of producing CNTs at scale [11]. The required acid-treatment and purification steps, typically involving HNO_3 or H_2SO_4 to remove catalyst and separate nanomaterials, have only been demonstrated at laboratory (some pilot [11]) scale and are not yet fully commercially deployed. Furthermore, limited data are available on the environmental burdens and waste stream associated with these processes, and the global CNT market remains small relative to other carbon products, making it susceptible to rapid oversupply (Table 5). Consequently, the CNT-upgrade pathway is evaluated assuming a constrained annual production of 719 t CNTs and is explicitly treated as a *theoretical upside case*, reflecting the non-commercial status of the separation process and associated technical, environmental, and market uncertainties.

On the other hand, selecting a ±10% sensitivity range for carbon black price in MP is supported by both market fundamentals and historical price stability [80,118,119]. Over the past decade, carbon black has traded within a relatively consistent band, typically between \$0.8 and \$1.5/kg, depending on grade and region, with a long-term mid-range around \$1.1/kg [80,119,120]. The U.S. market volatility during this period has been modest, with typical year-over-year fluctuations around 10–15%, even across periods of significant upstream feedstock volatility (e.g., oil and gas price swings) [80,119,120].

This price stability is due to carbon black's role as a mature, high-volume industrial material, anchored by strong baseline demand in tire and rubber manufacturing. The global market is well-developed, estimated at 15.1 million t/yr in 2025 [119,120], with inelastic demand and diversified supply chains helping to dampen extreme price shifts. These findings underscore that the economic viability of MP depends less on hydrogen sales alone and more on the stability of co-product markets and exposure to natural gas price fluctuations. To improve the feasibility of MP, novel applications that capitalize on carbon co-products are critical [73,121,122]. Li-ion batteries and steel production represent two promising markets, where MP can provide both high-quality graphitic carbon and clean hydrogen powered by renewable electricity [123]. Other opportunities are emerging as well, Monolith is using carbon black to decarbonize tire production, while

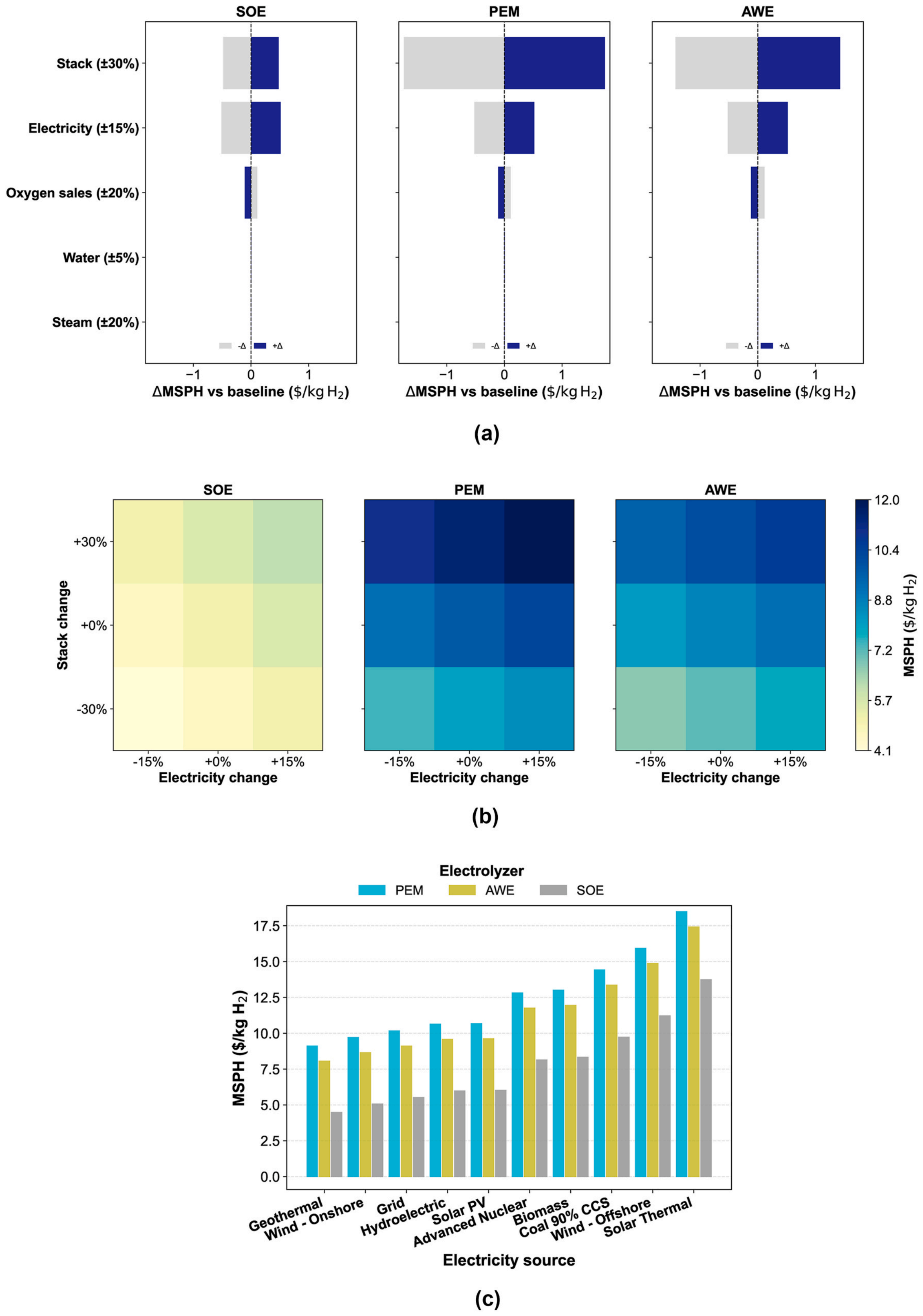


Fig. 3. Sensitivity analysis results for WE, a) OAT tornado plot, b) two-way sensitivity factor analysis, and c) MSPH for different electricity sources. AWE and PEM: pioneer plants (not demonstrated at the scale evaluated). SOE nth-plant.

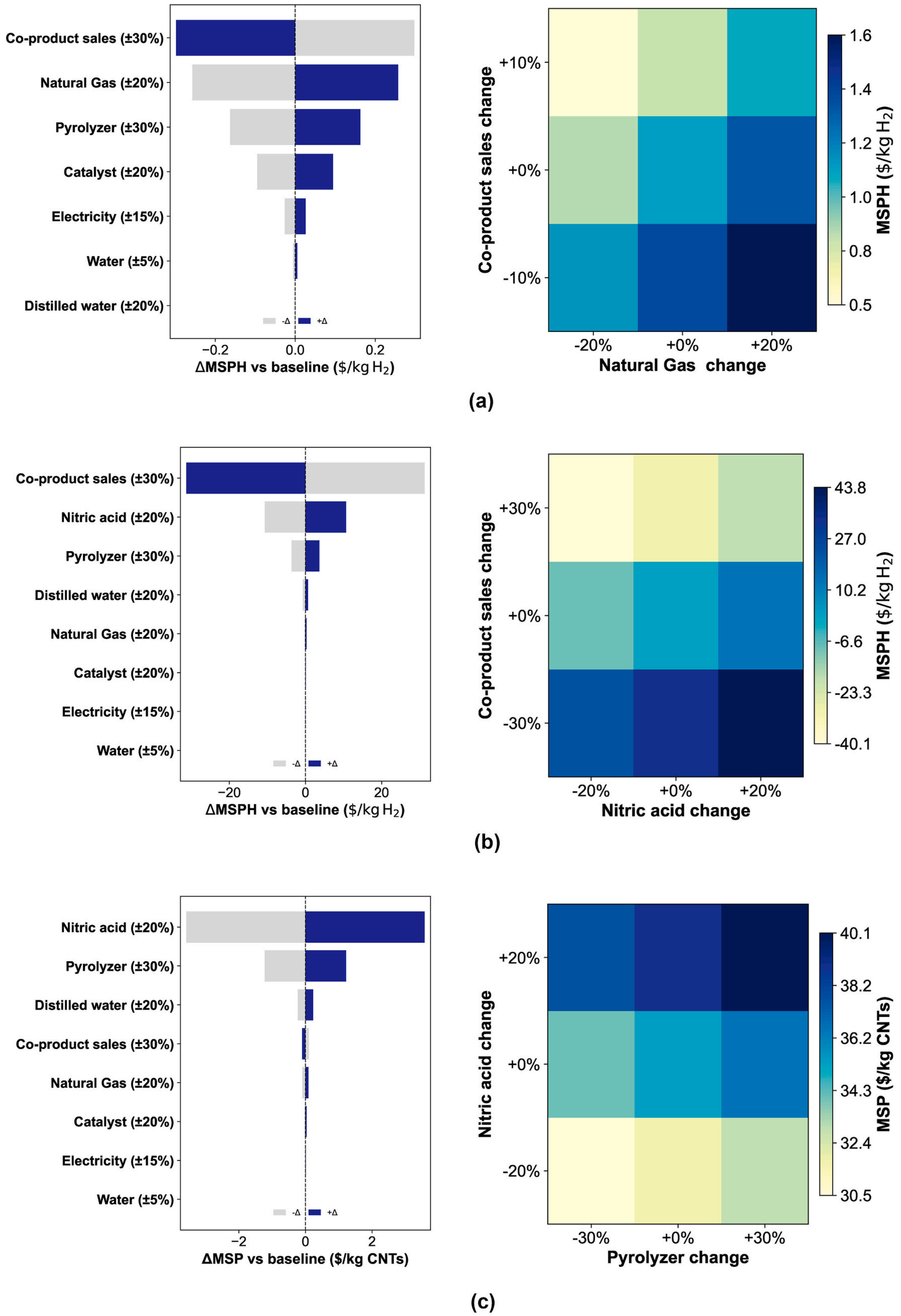


Fig. 4. Sensitivity analysis results for MP including OAT tornado plot and two-way sensitivity factor analysis for a) carbon black as a co-product and b) CNTs as a co-product, applicable range ≤1000 tons of natural gas per year.

Table 5
Carbon selling prices from MP [67,73,81].

Carbon type	Grade	Price ($/kg)	Market Size (metric t/yr)
Graphitic carbon	Amorphous powder	$0.22-0.30	*Global:* 80,000 (2015) 250,000 (2020)
Graphitic carbon	Crystalline graphite	$0.37-0.41	
Carbon black	N550	$0.66-0.78	*U.S.:* ~2,000,000 (2017)
Carbon black	Various	$0.76-1.50	*Global:* 12,000,000 (2014) 16,400,000 (2022)
CNTs	-	> $100	*Global:* 5000 (2014) 20,000 (2022)
Fibers	-	$25-113	*Global:* 70,000 (2016) 100,000 (2020)

Modern Hydrogen is exploring its use to reduce emissions in cement manufacturing.

3.2.3. Methane reforming: SMR, ATRM, POM, DMR

For SMR (Fig. 5a), the MSPH is most sensitive to natural gas price, reflecting the strong dependence of this pathway on methane as both feedstock and energy source. The reformer capital cost is the second most influential parameter, followed by electricity and distilled water inputs, which both play secondary roles. PSA packing and WGS catalysts have little influence. The two-way analysis shows that high natural gas costs quickly erode competitiveness, and improvements in reformer performance or cost reduction are critical to offset this risk.

In the sensitivity analysis for ATRM (Fig. 5b), natural gas remains the dominant cost driver, but co-product revenues (N_2 from the ASU) gain a more visible role. Electricity also plays a stronger effect due to the process's reliance on power for air separation and compression. Despite the worst-case scenario, characterized by high natural gas prices and low co-product revenues, the two-way analysis reveals that ATRM emerges as the sole technology capable of sustaining MSPH prices below $1.1/kg H_2.

POM (Fig. 5c) exhibits performance patterns similar to ATRM but results in a higher MSPH. This difference is primarily driven by its lower hydrogen yield (0.25 kg H_2/kg CH_4 for POM compared with 0.38 kg H_2/kg CH_4 for ATRM) and its higher electricity consumption (3.12 MWh/t H_2 for POM versus 1.74 MWh/t H_2 for ATRM). While overall equipment costs are comparable, POM's reformer is 57% more expensive than that of ATRM. Compared with other reforming pathways, ATRM offers the lowest baseline hydrogen production cost ($MSPH_{baseline}$ $0.76/kg H_2) making it the most economical choice for large-scale operations. This cost advantage explains its adoption by major companies like Air Products and Air Liquide [30].

For, DMR (Fig. 5c), although natural gas remains a key input, the cost and availability of carbon dioxide have an additional influence. Electricity consumption and reformer cost also contribute significantly to its cost structure, whereas PSA packing and water inputs have minimal impact. Two-way sensitivity analysis reveals strong interactions between natural gas and carbon dioxide costs when both are favorable. In such cases, its MSPH can fall into a competitive range. However, the volatility increases significantly when input rises. Furthermore, DMR's high MSPH is primarily due to its lower hydrogen yield and the absence of co-product revenue.

Although the uncertainty of DMR implementation at scale is accounted for in the pioneer-plant analysis, scale itself has a dominant influence on the resulting MSPH. To quantify this effect, several smaller plant capacities were evaluated. An exponential relationship between natural gas feed rate and MSPH was identified ($R^2 = 0.9831$), described by $MSPH = 8 \times 10^8 x^{-5.644}$, where x is the annual natural gas input (t/yr). Under this relationship, reducing the natural gas input to one-fifth of the baseline increases MSPH to $5.3/kg, while reductions to one-quarter and one-third raise costs to about $5.0/kg and $4.7/kg, respectively. These results therefore serve as exploratory upper and lower bounds, not as indications that DMR can achieve cost-competitive operation at present levels of technological maturity.

3.2.4. Biomass gasification

BG can be performed using a variety of waste feedstocks such as forest residues, or corn stover, although the lowest MSPH is accomplished with MSW (Table 6). Gasifier pressure has a minor impact, high pressure (HP) and low pressure (LP) gasification require similar capital investments. High pressure gasification achieves slightly higher hydrogen yields, which in turn lowers the MSPH.

The sensitivity analysis reveals that the drivers of MSPH in gasification-to-hydrogen systems differ by feedstock. For higher-cost feedstocks such as forest residues and corn stover, MSPH is dominated by biomass price, with co-product sales (N_2 from the ASU), electricity, and ash disposal contributing secondary influences. In contrast, for MSW, where feedstock cost is lower, MSPH is less sensitive to biomass price and more influenced by electricity and co-product sales (Fig. 6a).

Other utilities, including water, catalysts for the WGS and PSA, wastewater from tar removal, amine makeup for acid gas removal, and distilled water, have no significant impact on the MSPH elasticity.

Syngas quality and contaminant formation can also affect the economics of all gasification pathways by increasing gas-cleaning requirements, parasitic energy demand, and potentially lowering effective hydrogen yield, with these effects being particularly relevant for heterogeneous feedstocks such as MSW. In the scenario analyzed here, syngas cleaning was modeled to remove fine particulates (ash) and sulfur species prior to the WGS reactor, see diagram and syngas composition in the open-source TEA [47]. Under the selected operating conditions for the gasifier (870 °C and 28 bar), species remaining unconverted after WGS were recirculated to the gasifier; therefore, tar was not represented as a separate output stream in this analysis.

Two-way interaction analyses highlight that for forest residues and corn stover MSPH is jointly determined by biomass supply costs and co-product markets, while for MSW, volatility is governed by the interplay of electricity and nitrogen sales (Fig. 6b). This suggests that MSW reduces feedstock cost exposure but increases sensitivity to market and utility price swings, whereas lignocellulosic feedstocks face greater delivered-cost sensitivity (harvest/collection, handling, and transport). Ash disposal also contributes materially, underscoring the need for integrated waste management.

3.2.5. Discount rate

The baseline real discount rate of 10% is common in academic studies, however, investment at the required levels may demand a higher return. Investors may require a return of 15% or more, which may better represent the hurdle rate, or the rate needed to overcome actual and bias-based risks. Increasing the real discount rate to 15% from 10% increases the MSPH by an average of 6%, with a range of 2% to 18% (Fig. 7 top). The average increase equates to an increase of $0.3/kg H_2 (Fig. 7 bottom). The largest absolute increase calculated was $0.6/kg H_2 for WE-PEM with solar thermal electricity. While this is the largest absolute increase, the percentage change was low at only 3%. The highest percentage change was 18% for MP powered by grid electricity, corresponding to a $0.2/kg H_2 increase in the MSPH.

3.3. Carbon intensity without CCUS

This section presents the CI results for each technology without CCUS. For WE, CI is dictated by emissions associated with the electricity source employed. Low-cost electricity improves economic performance, but low-carbon electricity is essential to remain competitive in CI terms. As shown in Fig. 8a, using average grid electricity can lead to CI values exceeding those of methane-reforming pathways, which aligns with findings in the literature [7]. Because electricity accounts for ~ 70% of WE operating costs (~50 kWh/kg H_2, 60% efficiency) [64,124,125], WE

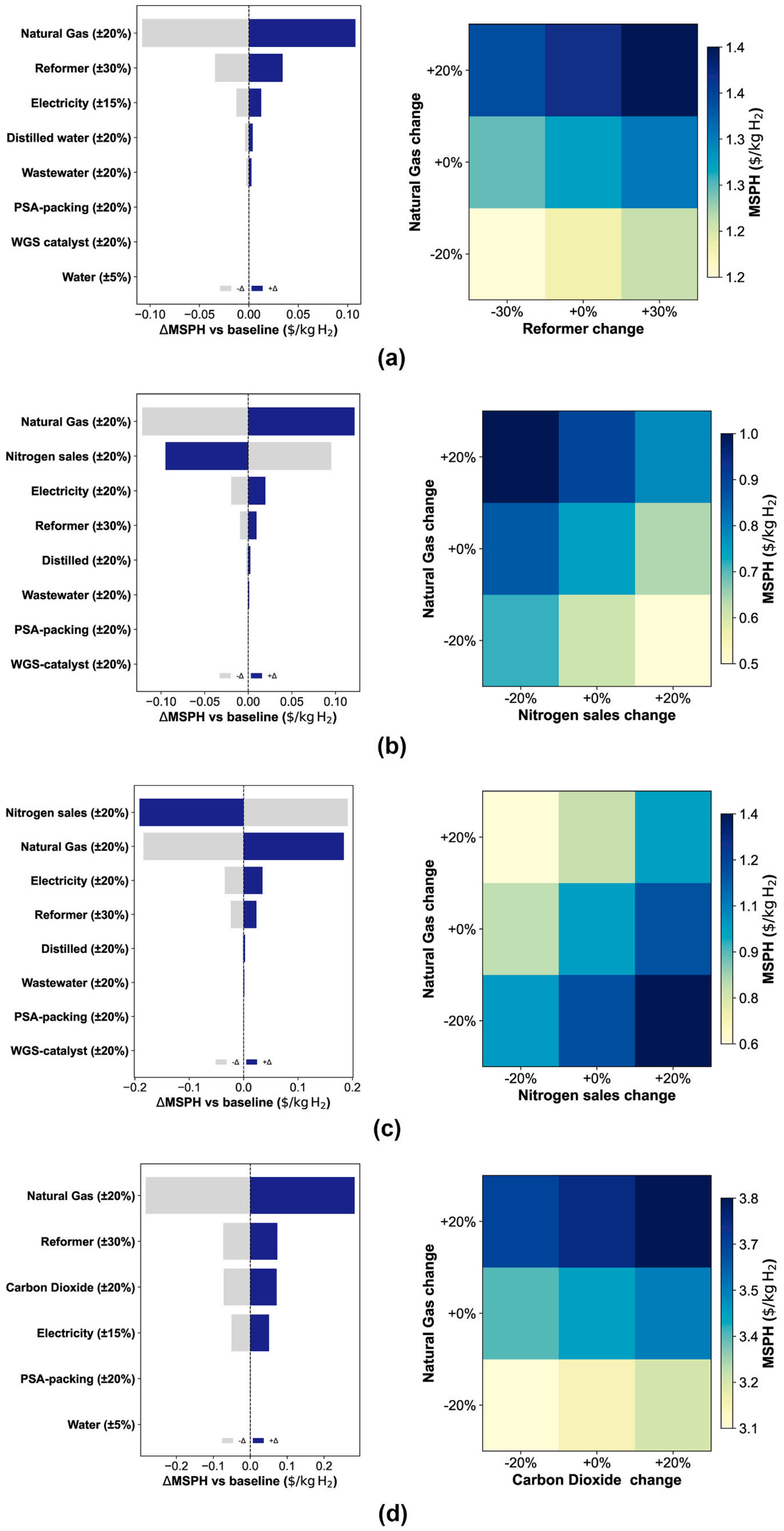


Fig. 5. Sensitivity analysis results including OAT tornado plot and two-way sensitivity factor for methane reforming pathways.

Table 6
Baseline TEA results for Gasification with different biomass.

Biomass	High Pressure ($/kg H_2)	Low Pressure ($/kg H_2)
MSW	2.4	2.7
Forest residues	3.4	3.8
Corn stover	3.0	3.3

systems must balance both the price and CI of power.

Fig. 8b summarizes the contribution process, energy, and upstream emissions to the CI of each pathway. Overall, results fall within literature ranges [30,126–128], though methodological differences exist. For example, GREET-based studies typically include biomass collection and fertilizer use for bio-based systems and may assume different process heat sources (such as diesel or electricity), while upstream catalyst-related emissions are often excluded. For reference, the calculated CI for SMR in this work is 77.2 g CO_2e/MJ (LHV) compared to GREET values reported of 86.93 g CO_2e/MJ (well-to-gate) and 117.67 gCO_2e/MJ (well-to-wheels) [129].

Among fossil-based pathways, SMR remains the reference technology due to its maturity, high hydrogen yield (0.6 kg H_2/kg CH_4), and widespread industrial adoption. However, it also exhibits one of the highest process-related CIs, making the most attractive candidate for decarbonization, with the largest potential for absolute emissions reduction. Roughly two-thirds of SMR emissions originate from direct process CO_2 generation, while the remaining third is associated with upstream natural gas supply, electricity, and raw materials.

ATRM exhibits a similar emissions profile, with 53% of its emissions arising from direct process CO_2 generation and the remainder from upstream natural gas supply, electricity and raw materials. Its CI is slightly lower than that of SMR because oxygen integration reduces the external energy required to maintain the reforming reaction. Nevertheless, ATRM still depends heavily on natural gas, such that both upstream natural gas supply and process CO_2 remain major contributors to its overall CI.

POM shows an even greater dependence on upstream natural gas, with nearly 45% of its emissions attributable to natural gas supply. This is largely due to its higher natural gas consumption per unit of hydrogen produced. Because a portion of the natural gas is oxidized to provide process heat rather than converted into H_2, POM has a lower effective hydrogen yield. Consequently, although POM may offer advantages in terms of MSPH, its environmental performance is less favorable than SMR, because smaller share of process-related CO_2 that can be capture, and ATRM, due to its lower oxygen use and correspondingly higher natural gas requirements.

DMR has the potential to utilize CO_2, but it does not inherently eliminate CO_2 emissions. The CI of DMR heavily depends on the origin and cost of the feedstock (CH_4 and CO_2). If the captured CO_2 is used in the process, it can reduce emissions, as demonstrated in Fig. 8b, where the emissions from the process are lower compared to other reforming technologies. DMR can reduce its carbon footprint if CH_4 and CO_2 are sourced from biogas, reaching a CI ~5 kg CO_2e/kg H_2 [130], bio-products derived from biomass decomposition, or landfill gas [131–134]. Moreover, the efficiency of electricity and reformers also plays a crucial role in the overall effectiveness of DMR.

MP has a low CI compared to conventional reforming, as solid carbon is the primary by-product as opposed to CO_2. While MP reduces direct process emissions, it still inherits upstream natural gas emissions

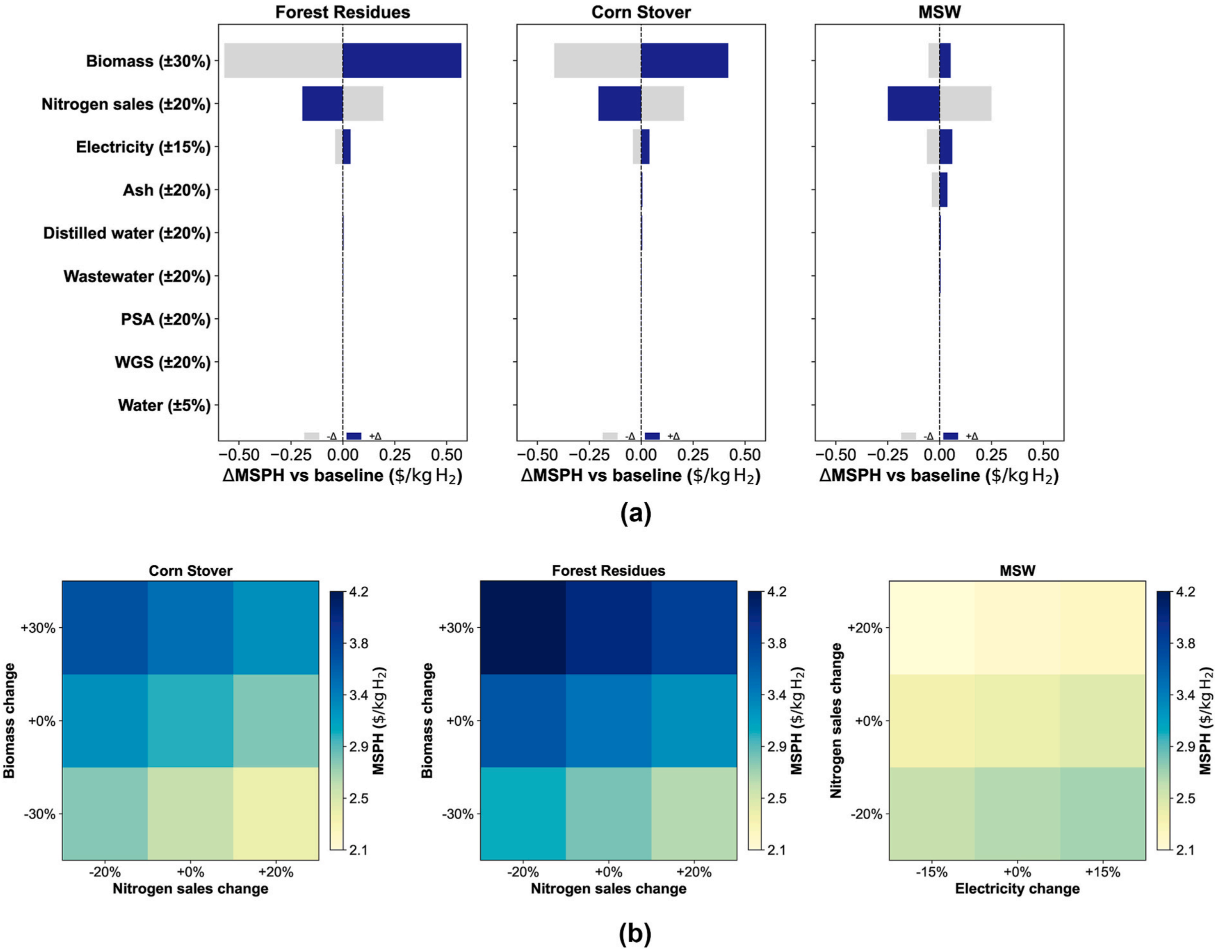


Fig. 6. Sensitivity analysis results for HP gasification a) OAT tornado plot and b) two-way sensitivity factor analysis for each biomass.

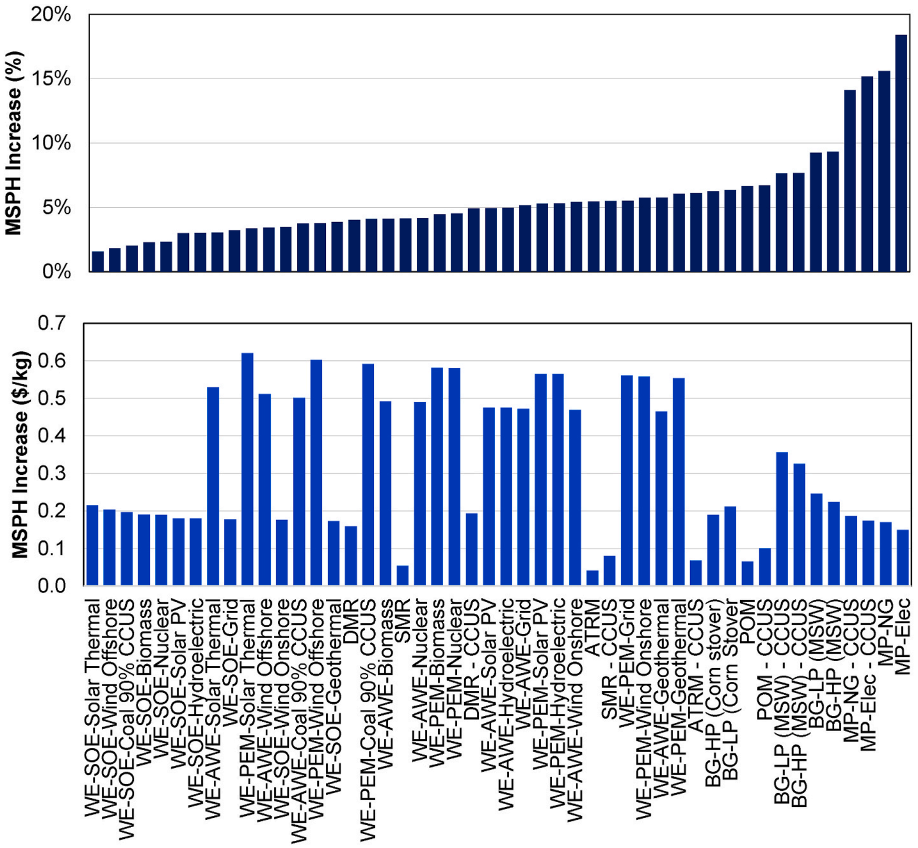


Fig. 7. Percent (top) and absolute (bottom) increase in MSPH for each production technology resulting from a real discount rate change from 10% to 15%.

(extraction, transportation) and natural gas combustion for heat supply. BG stands out as the only bio-based pathway. Its overall CI is the lowest (excluding WE) because biogenic carbon is considered renewable, though some emissions come from electricity, upstream raw material manufacturing, and ash disposal.

3.4. *Carbon intensity with CCUS*

Fig. 9 illustrates the comparative impact of CCUS on CI and MSPH across the evaluated technologies, reinforcing the trade-offs between emission reductions and economic viability. Table S5 summarizes literature values for the impact of CCUS integration on the MPSH and provides a point of comparison with the results of this study. For ATRM, POM, SMR, and BG, the CCUS-induced increase in MSPH reported in the literature is within ± $0.35/kg H_2 of the values calculated here. In contrast, literature estimates for DMR indicate a CCUS penalty that is approximately 1 $/kg H_2 lower.

Comparison with U.S. DOE reports [135] further contextualize the results obtained. For example, ATRM with CCUS (excluding co-product revenue because they vent the N_2 after the ASU) yields an MSPH of $1.58/kg H_2 in this work, compared with $1.59/kg H_2 reported by the U.S. DOE, whereas for SMR with CCUS, the MSPH obtained here is $1.99/kg H_2 compared with $1.64/kg H_2 [135]. These discrepancies are primarily attributed to variations in system boundaries, capture configurations and efficiencies, and assumptions regarding CO_2 utilization or storage. Nevertheless, the results remain comparable in magnitude, supporting the CCUS cost assumptions employed in this analysis.

SMR, ATRM, and POM show comparatively elevated baseline CI, primarily due to emissions associated with the natural gas supply chain and the CO_2 released directly within each process. Integrating CCUS significantly lowers the CI of these reforming pathways, but it also introduces substantial CAPEX and OPEX.

In contrast, DMR shows the highest CI among fossil-based pathways, with approximately 97% of its emissions originating from upstream methane and CO_2 supply. Consequently, CCUS has limited impact on this process [136], its main role is the potential reintegration of a fraction of CO_2 from natural gas combustion into the reformer. However, this approach increases MSPH due to the additional capital cost and electricity demand of the CCUS unit, while leaving upstream emissions largely unaffected. Consequently, the carbon intensity of DMR is fundamentally constrained by the source and quality of its feedstocks (CH_4 and CO_2).

MP produces solid carbon rather than CO_2, resulting in lower intrinsic process emission. For consistency with the other reforming technologies compared in this study (Fig. 9), the baseline MP case assumes the process is powered by natural gas combustion, mirroring the heat supply configuration of the other pathways. Under this harmonized assumption, the CI of MP reflects emissions from natural gas supply, extraction and combustion rather than from the core conversion reaction itself. Because MP is sensitive to the CI of its heat source, powering the process with low-carbon electricity has strong potential to further reduce emissions.

Accordingly, the open-source TEA [48] also includes a renewable-powered configuration, specifically using onshore wind, one of the lowest-cost and lowest-CI electricity sources in the U.S. Under this scenario, the MSPH decreases to $0.6/kg H_2 with a CI of 4.0 kg CO_2e/kg H_2. Even when higher-cost electricity sources, such as solar thermal (Table 2), the MSPH remains relatively low at $1/kg H_2 while the CI remains near 4.1 kg CO_2e/kg H_2. These results emphasize MP as a promising pathway for further development, with electrification representing a significant opportunity for deeper decarbonization. Electrification methods reported in the literature and in emerging commercial applications include plasma (already deployed at commercial scale) [11], solar-thermal systems [122], microwave heating, and induction

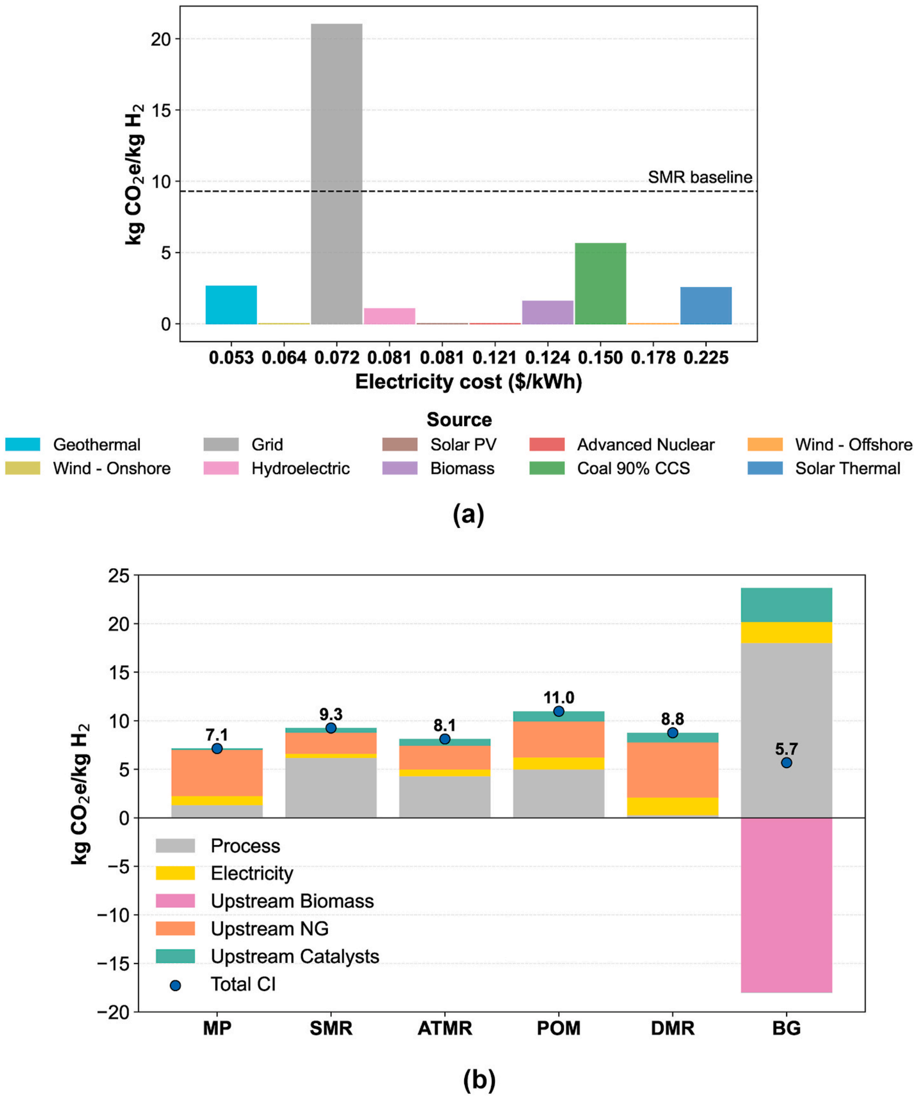


Fig. 8. Carbon intensity (kg CO_2e/kg H_2) for the baseline TEA scenario (Fig. 2). GWP is estimated using AR6, which is a 100-year time horizon: a) CI of WE using different electricity sources ($/kWh from Table 2), and b) CI components and total values for all other technologies. NG: natural gas.

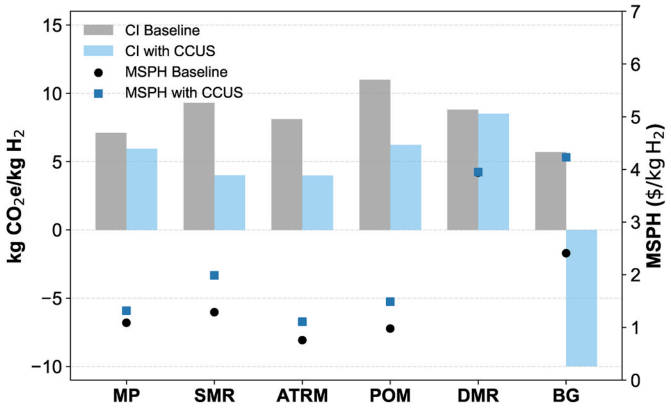


Fig. 9. Carbon intensity and MSPH for TEA baseline scenario and CCUS scenario.

heating [11].

BG stands out with negative CI values when CCUS is implemented, indicating a potential for net carbon removal. Nonetheless, this strong climate benefit is accompanied by a relatively high MSPH, underlining significant economic barriers. Besides, explicitly accounting for biomass transportation and handling increases the MPSH of the biomass-gasification pathway by approximately $0.17/kg H_2 and 0.22 kg CO_2e/kg H_2 (based on a transportation cost of $12.58 per dry ton, a transport-related emission burden of 16.43 kg CO_2e per dry ton of biomass, and an nth-plant hydrogen yield of ~75 kg H_2 per dry ton of biomass) [76].

These results evidence that while CCUS is the main lever for reducing emissions in conventional reforming pathways, emerging technologies such as MP and BG could deliver deeper decarbonization, provided that challenges of cost, scalability, and infrastructure are overcome. Still, the economic penalty of CCUS can be substantial. MSPH increases by 21% for MP, 54% for SMR, 42% for ATRM, 44% for POM, and 67% for BG. Reducing the price of the CCUS demands minimizing the energy penalty associated with the CCUS equipment's operation. To achieve this, various technologies are being explored, such as membrane adsorption, hybrid concepts, and chemical looping, which aim to compensate for this energy issue [136,137].

Interestingly, DMR is the only exception, where CCUS reduces MSPH by 8% since the process can utilize the captured CO_2 on-site, avoiding CO_2 feedstock costs and CO_2 pipeline transportation. This contrast underscores the importance of technology-specific strategies for advancing low-carbon H_2. A potential alternative configuration is using renewable natural gas, with a CI around −7.8 kg CO_2e/kg H_2 (−65.2 g CO_2e/MJ) for ATRM and 1.1 kg CO_2e/kg H_2 (9.3 g CO_2e/MJ) for MP [88].

These findings are particularly relevant in the context of the U.S. DOE's initial CHPS, established under Section 40315 of the Bipartisan Infrastructure Law (BIL). The CHPS sets a lifecycle, or "well-to-gate," GHG emissions target of ≤4 kg CO_2e/kg H_2 produced. Based on the present analysis, the pathways capable of achieving CI values below this threshold include WE powered by renewable electricity, BG with CCUS, and SMR or ATRM with CCUS, if capture efficiencies ≥90%. However, if the capture efficiencies are lower than the assumed 90%, CIs will increase and incentive values will likely drop. A clear understanding of the emissions profiles across different production routes is therefore essential for evaluating which technologies are most likely to comply with the CHPS and, by extension, to play a vital role in scaling low-carbon hydrogen production [30].

3.5. Abatement cost and U.S policy

Abatement cost enables the ranking of the financial efficiency of each technology in reducing emissions. Government policies are used to address abatement cost, although they often fall short of required values. To assess the impact of policy, we calculated the baseline abatement cost without policy support and compared this baseline to the marginal abatement cost after implementation of three policy scenarios: 1) 45V, 2) 45V plus the minimum CA LCFS credit value, and 3) 45V plus the median CA LCFS credit value (Fig. 10).

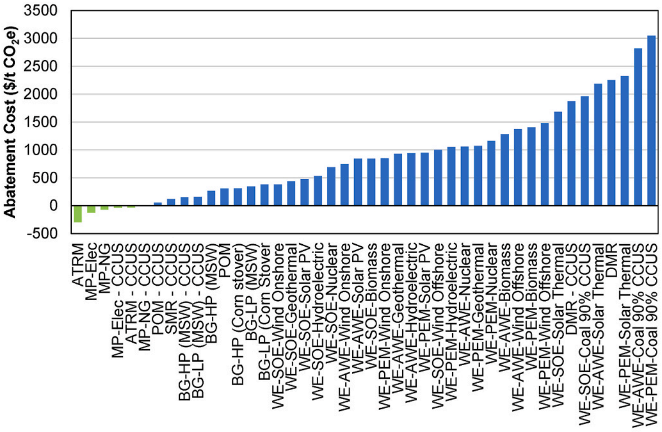
Not surprisingly, the abatement costs dropped with the addition of policy support, but very few technologies were supported enough to reach a zero or negative marginal abatement cost, which signals the MSHP has reached or surpassed cost parity with SMR of natural gas. With the addition of 45V, no additional technologies' abatement costs drop to or below zero. However, with the addition of LCFS at its minimum value, all the technologies that utilize CCUS have become cost competitive. WE-SOE-wind onshore is the lowest abatement cost WE scenario, but additional support is needed. It should be noted that this analysis assumes all three pillars are met for 45V, which will be more challenging start in 2030 when hourly matching is implemented.

Selecting a location that satisfies the requirements of all three pillars will be challenging. In addition to installing new, renewable, local electricity generation, hourly matching will be required starting in 2030. Hydroelectric and nuclear power face significant bureaucratic and community acceptance barriers, though meeting hourly matching is less challenging. Wind and solar may have lower hurdles in siting and installation, but hourly matching will require substantial energy storage to provide electricity during periods without sunlight or with incompatible wind levels. For example, if a WE facility using onshore wind has to purchase half its electricity from the grid, the hydrogen CI increases by an estimated 10.5 kg CO_2/kg H_2. This increase eliminates eligibility for 45V funding and reduces CA LCFS credit generation by 97%. Alternative CI calculation methodologies for temporal matching may alleviate some of the current burden but have not been legislated.

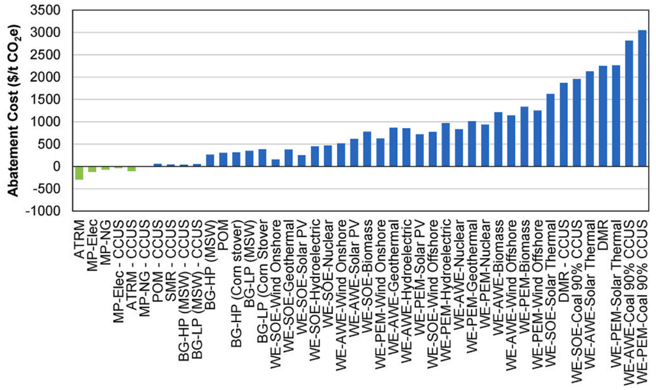
For technologies that utilize CCUS, producers can select between 45V and 45Q to maximize policy support. Fig. 11 compares the impact of 45V and 45Q on the abatement cost for each technology. The superiority of these policies is pathway dependent with ATRM-CCUS, BG-HP (MSW)-CCUS, and BG-LP (MSW)-CCUS benefitting most from 45V and MP-Elec(Grid)-CCUS, MP-NG-CCUS, POM-CCUS, SMR-CCUS all more cost effective with 45Q. However, if the construction timeline or the three pillars required for 45V cannot be met, 45Q will contribute to minimizing abatement cost. If carbon capture efficiency is below 90%, the trade-off between an increased hydrogen CI and the corresponding lower 45V value and a reduced volume of captured of CO_2 and the resulting drop in credit generation, may shift policy eligibility and which policy is most financially advantageous.

The results in Figs. 10 and 11 indicate that policy support not only

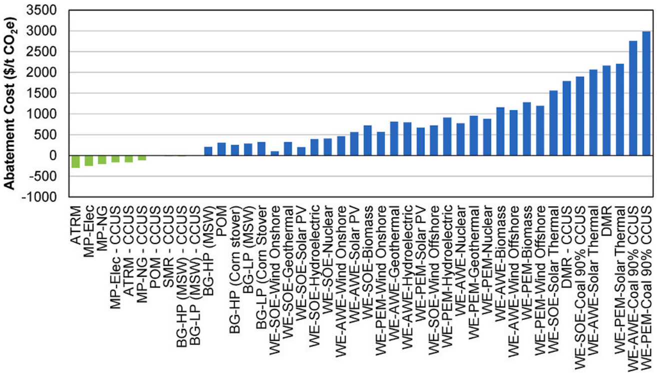
a) Baseline no policy



b) 45V



c) 45V + min LCFS



d) 45V + median LCFS

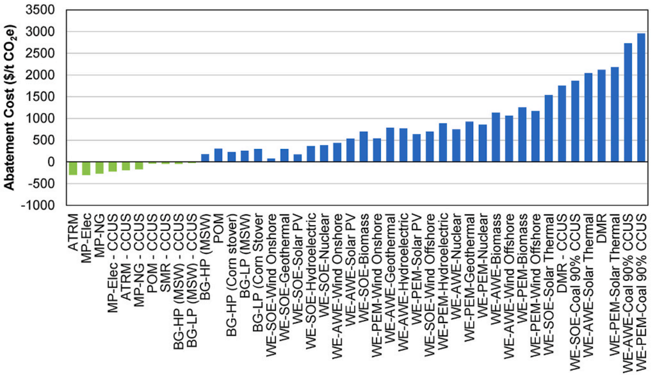


Fig. 10. Abatement cost and policy support scenarios: a) baseline with no policy support, b) marginal with 45V, c) marginal with 45V and min LCFS, d) marginal with 45V and median LCFS.

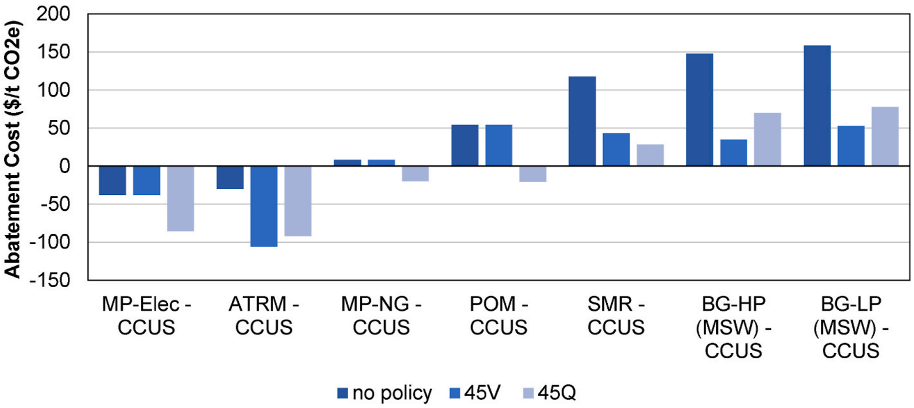


Fig. 11. Abatement cost and policy support scenarios for no policy, 45V, or 45Q for technologies implementing CCUS.

lowers abatement costs but also reshapes the relative attractiveness of hydrogen pathways. Fig. 10 illustrates that stacking 45V with LCFS credits can move most natural gas- and biomass-based CCUS routes from clearly positive to near-zero or negative abatement cost, whereas WE options remain comparatively expensive even under optimistic credit values. Fig. 11 further reveals two distinct archetypes among CCUS pathways: low-CI configurations that benefit more from CI-based 45V, and high–CO_2-capture routes that see larger gains under mass-based 45Q. These patterns imply that generous, stacked incentives are essential to close the green premium for most low-CI hydrogen options and that the choice between 45V and 45Q will materially influence which technologies are deployed first.

4. Conclusions

This study provides a harmonized, open-source techno-economic and environmental assessment of seven hydrogen production pathways in the U.S., linking process conditions, CI, and policy support within a single, comparable framework. By standardizing financial assumptions, system boundaries, and emission factors, the work enables direct comparison of MSPH, cradle-to-gate CI, and CO_2 abatement cost across fossil-, biomass-based and WE technologies, with and without CCUS.

Economically, thermal conversion pathways based on natural gas and biomass exhibit baseline MSPHs between $0.8 and $3.9/kg H_2, with ATRM emerging as one of the lowest-cost large-scale options when operated at industrially relevant capacities. WE pathways are consistently more expensive, with MSPHs spanning $4.5–$18.5/kg H_2 depending on electrolyzer technology and electricity source. Across all technologies, MSPH is most sensitive to a small set of drivers: fuel and electricity prices, electrolyzer stack costs for WE, reformer capital costs for methane reforming routes, and revenues from co-products such as oxygen, nitrogen, and carbon black. The strong dependence on co-product markets highlights a key area of financial vulnerability often overlooked in technology evaluations. To mitigate this risk, one promising approach is technology integration, such as combining WE with ATRM or BG, where process synergies can reduce reliance on volatile co-product markets.

From an environmental perspective, CI values vary widely by pathway and configuration. Conventional SMR, ATRM, and POM exhibit high CIs dominated by process CO_2 and upstream natural gas supply, whereas MP and BG offer lower CIs because carbon is stored as a solid product or treated as biogenic. Incorporating CCUS reduces CI for all fossil-based routes, with particularly large reductions for SMR and ATRM, and can drive BG to net-negative emissions when biogenic CO_2 is captured and stored. However, these CI improvements come with sizeable cost penalties, CCUS increases MSPH by 21–67 % for most technologies, highlighting the importance of lowering the energy penalty and capital cost of capture systems. DMR is a notable exception in which on-site use of captured CO_2 can modestly reduce MSPH.

While MSPH is important to a technology pathways success, abatement cost quantifies the cost of lowering emissions and is often tied directly to policy support. When CI results are evaluated against emerging clean hydrogen standards, several configurations are capable of meeting a $\leq$4 kg CO_2e/kg H_2 threshold, including WE supplied with low-carbon electricity, BG with CCUS, and SMR or ATRM with high capture efficiencies. These pathways therefore represent plausible candidates for compliance with the U.S. CHPS and similar policies. Yet cost competitiveness relative to grey hydrogen remains a limiting factor, particularly for WE and BG configurations with higher MSPHs.

By converting TEA and CI outputs into abatement costs, the analysis explicitly quantifies the cost of avoiding one t of CO_2e relative to conventional SMR. In the absence of policy support, most low-CI hydrogen pathways exhibit positive abatement costs, indicating that they are not financially attractive on their own. Incorporating federal 45V production tax credits and California LCFS credits reduces abatement costs across the board and enables several CCUS-equipped pathways to reach or surpass cost parity with SMR. Nevertheless, while some of the WE H_2 pathways have near zero CI values, their corresponding MSPH are so high that abatement costs do not demonstrate a cost-effective method of reducing emissions.

Decarbonizing hydrogen supply will involve a portfolio of technologies and integration rather than a single dominant solution, as suggested by these results. In the near to medium term, ATRM and SMR with CCUS, MP, and BG with CCUS appear well-suited to deliver lower-CI hydrogen at modest cost increases, particularly when supported by targeted incentives and co-product market integration. WE remains crucial to long-term green hydrogen strategies, but coordinated progress on three fronts are required: 1) affordable, low-carbon electricity, 2) reduced electrolyzer capital costs, and 3) minimizing reliance on expensive materials like platinum, iridium, and titanium. Additionally, sufficient, long-term policy support is essential. Rising natural gas prices strengthen the case for renewable electricity, making it environmentally and economically attractive. However, cost parity without significant policy support is not realistic. Based on the results of this work, WE-SOE-onshore wind could emerge as a strong alternative to fossil-based hydrogen production.

Finally, the available open-source TEA and CI models developed here offer a practical tool for extending the analysis to other regions, feedstocks, and end use. By providing transparent, harmonized benchmarks for cost, emissions, and abatement under current U.S. policy, this work aims to support stakeholders in designing integrated supply chains, identifying promising technology combinations, and prioritizing research, development, and deployment efforts for low-carbon hydrogen.

CRediT authorship contribution statement

Valentina Sierra-Jimenez: Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Kristin Brandt:** Writing – review & editing, Supervision, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Aidan Garcia:** Writing – review & editing, Investigation, Formal analysis. **Manuel Garcia-Perez:** Writing – review & editing, Supervision, Project administration, Investigation, Funding acquisition, Conceptualization. **Michael P. Wolcott:** Writing – review & editing, Supervision, Project administration, Methodology, Funding acquisition, Conceptualization.

Notes

The authors declare no competing financial interest.

Declaration of competing interest

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

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2026.154856.

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16. Abstract

Comparing studies that involve techno-economic analyses (TEA) and life cycle assessments (LCA) for different hydrogen production technologies is challenging due to inconsistent assumptions across studies. Thus, this research develops a harmonized framework to assess seven hydrogen production pathways - water electrolysis, methane pyrolysis, biomass gasification, steam methane reforming, autothermal reforming, partial oxidation, and dry methane reforming, under consistent U.S.-specific techno-economic, carbon intensity (CI), and policy assumptions. Process models developed with Aspen Plus produce mass and energy balances, informing opensource TEA and cradle-to-gate CI estimates. Thermal conversion pathways produce hydrogen at \$0.8–\$3.9/kg, while electrolysis-based methods range from \$4.5–\$18.5/kg, contingent on both electrolyzer and the source of electricity used. Several low-carbon emitting pathways meet emerging clean hydrogen standards, but only some achieve cost parity with conventional hydrogen under current U.S. federal and state incentives. This framework enables consistent cross-technology comparison and supports informed decisions on hydrogen sourcing, including applications such as sustainable aviation fuel production or fuel cell electric vehicles.

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Hydrogen production technologies, Techno-economic analyses, Policy support, Carbon intensity, Abatement cost, ASCENT

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