

Research paper

Delivered Cost and Production-Stage Emissions of Nuclear-Produced Hydrogen for Fuel Cell Vehicles: A Model-Based Case Study

Ahmed Rayyan¹, Malalai Kiwan^{1,*}¹ University of Engineering and Technology Peshawar, Peshawar, Pakistan* Corresponding author: 23pwmec5328@uetpeshawar.edu.pk

Abstract: Hydrogen fuel cell vehicles (FCVs) offer a low-emission alternative to petroleum-based transport, and nuclear energy has been proposed as a low-carbon, continuous-supply feedstock capable of meeting projected hydrogen demand growth. Existing literature addresses nuclear hydrogen production and FCV performance largely from either a production-side or vehicle-side perspective; while some studies extend past the plant gate into transport or full-chain emissions, the studies identified in this review do not jointly harmonize cost and environmental accounting for a matched reactor–vehicle configuration. This paper presents an integrated techno-economic and environmental case study of nuclear-produced hydrogen for FCVs, using a light water reactor-integrated high-temperature steam electrolysis (HTSE) plant paired with a passenger FCV as a representative configuration, informed by a review of the existing techno-economic and environmental literature on nuclear hydrogen production and FCVs. Harmonized to a common reference year, plant-gate production cost is \$2.40/kg, rising to \$13.76–22.22/kg delivered (40% station utilization base case) once transportation, storage, and station dispensing, the dominant cost driver, calculated using Argonne's HRSAM model, are included. Well-to-gate emissions, calculated using Argonne's 45VH2-GREET 2023 model, are 0.10 kg CO₂-eq/kg H₂, corresponding to production-stage emissions of 1.4 g CO₂-eq/mile. For comparison, using GREET 2023 fuel-cycle electricity emission factors, the representative BEV produces 105.5 g CO₂-eq/mile on the U.S. average electricity mix and 0.66 g CO₂-eq/mile under the LWR nuclear-electricity scenario. These results demonstrate the strong influence of electricity supply on BEV emissions; however, the FCV and BEV values represent different stages of the respective energy pathways and should not be interpreted as a fully harmonized vehicle-level life-cycle comparison. Within this specific configuration, nuclear-coupled hydrogen has a substantially lower estimated delivered cost than the most recent available retail benchmark, while dispensing infrastructure and policy conditions remain important determinants of its economic competitiveness. These findings are illustrative of one representative case and should not be generalized across reactor types, delivery configurations, or vehicle segments; harmonized data across additional configurations remain a priority for future work.

Keywords: Fuel cell vehicles (FCV), Nuclear hydrogen production, Well-to-gate emissions, Techno-economic analysis

1. Introduction

The transport sector remains heavily dependent on petroleum-based fuels, and decarbonization efforts have increasingly turned to hydrogen as a promising energy carrier, particularly for heavy-duty and long-distance vehicle segments that are difficult to electrify directly [1]. However, most hydrogen produced today comes from fossil fuels, mainly via steam methane reforming (SMR), resulting in substantial associated CO₂ emissions [2]. In the United States alone, hydrogen production consumes nearly 5% of national natural gas usage and generates approximately 77 million tonnes of CO₂ annually [3].

Nuclear energy offers a low-carbon alternative that can meet the anticipated growth in hydrogen demand [2]. Unlike variable renewable sources such as solar and wind, nuclear power plants provide continuous, weather-independent electricity generation, and advanced reactor designs can also supply the high-temperature process heat needed to improve hydrogen production efficiency [4]. Nuclear energy can produce hydrogen through three principal pathways: low-temperature electrolysis, high-temperature steam electrolysis, and thermochemical water-splitting cycles. Each pathway differs in operating temperature, energy requirements, efficiency, and technology maturity.

DOI: <https://doi.org/10.66173/jenmas.2026.283>

Received 27 July 2026, Revised 12 September 2026, Accepted 27 September 2026, Available online 10 October 2026

©2026 The Author(s). Published by SEMS. This is an open-access article under the CC BY license (<https://creativecommons.org/licenses/by/4.0/>).

Several nuclear-coupled hydrogen production routes are currently under active development, including low-temperature electrolysis, high-temperature steam electrolysis (700–950 °C), and the sulfur–iodine thermochemical cycle. Japan and China are pursuing the sulfur–iodine cycle using the HTTR and HTR-PM600 reactors, respectively [4]. These developments are further supported by coordinated international initiatives, including the IAEA's nuclear hydrogen programs and the U.S. Department of Energy's H2@Scale program, which aim to accelerate the large-scale production of low-carbon hydrogen from nuclear energy sources [5].

Hydrogen fuel cell vehicles (FCVs) produce zero tailpipe emissions and represent a compelling alternative to internal combustion and battery electric vehicles (BEVs) for applications requiring long range and rapid refueling. However, their broader deployment remains constrained by the cost and carbon intensity of the hydrogen supply chain. The U.S. Department of Energy's Hydrogen Shot initiative targets a production cost below \$2/kg by 2026, and \$1/kg by 2031, yet current electrolytic hydrogen production costs remain in the range of \$6–8/kg [6]. Nuclear-coupled high-temperature steam electrolysis (HTSE) has been proposed as one pathway toward closing this gap, though its cost competitiveness depends strongly on reactor integration and electricity pricing assumptions [7]. Where hydrogen is not produced cleanly, affordably, and reliably, the well-to-wheel environmental advantage of FCVs over conventional vehicles is substantially eroded, and their cost competitiveness relative to BEVs is further undermined.

Existing studies provide important but complementary coverage of the problem. Reviews of hydrogen-production techno-economics, such as Nemitallah et al. [8], examine the costs and technology status of hydrogen-production pathways broadly but do not develop a matched nuclear-reactor/FCV case study. Reviews focused on fuel cell vehicles, such as Halder et al. [9], synthesize vehicle performance, emissions, and economic considerations across hydrogen pathways but do not trace a specific nuclear-integrated production system through downstream delivery to a defined vehicle. Mohideen et al. [10] examine the techno-economics of different hydrogen pathways for fuel-cell electric vehicles, but do not develop the nuclear-coupled reactor–electrolyzer, station-level delivery, and vehicle case considered here. Lyu et al. [11] extend the environmental assessment of FCVs across the hydrogen supply chain, while Li et al. [12] examine the life-cycle environmental performance of a nuclear-based hydrogen system including downstream logistics; neither provides the combined cost and station-level economic treatment developed in the present case study. Thus, to the best of our knowledge, based on the literature reviewed in this study (Section 3.2), which does not claim systematic completeness, the contribution of this paper is not that these individual dimensions have not previously been studied, but that it integrates them within a defined nuclear-integrated HTSE configuration, a representative refueling station, and a passenger FCV while explicitly harmonizing the available cost data and documenting where environmental and economic boundaries cannot be fully aligned.

To address this gap, this review synthesizes the techno-economic and environmental literature on nuclear-produced hydrogen as a fuel source for FCVs and illustrates its practical implications through a representative case study. The specific objectives are to: (i) synthesize the techno-economic literature on hydrogen production using nuclear energy relevant to FCV applications; (ii) synthesize the life-cycle environmental literature on nuclear-produced hydrogen in comparison with conventional and renewable hydrogen production pathways; (iii) illustrate, through a single representative reactor–electrolyser configuration and vehicle case, how production-level cost and emissions figures translate into vehicle-relevant outcomes, delivered (pump) cost and well-to-gate emissions, harmonizing cost and emissions figures to a common reference year and system boundary wherever the underlying data permit, and making explicit where they do not.

By integrating the techno-economic and environmental literature on nuclear hydrogen production within a single framework, and by illustrating how plant-level figures translate into vehicle-relevant outcomes for one representative configuration, this study aims to clarify the extent to which current evidence supports these outcomes, and identify the limits of that evidence, and to identify where further study, across additional reactor types, vehicle segments, and harmonized primary data, is needed before broader conclusions can be drawn.

2. Literature Review

2.1 Nuclear Hydrogen Production Pathways

2.1.1 Low-Temperature Electrolysis

Low-temperature electrolysis (LTE) uses electricity from a nuclear power plant to split water into hydrogen and oxygen at near-ambient temperature, using either PEM or alkaline (AWE) cell technology [13,14,15]; PEM offers faster dynamic response, while alkaline is more mature and lower-cost [16,17,18].

Reported stack efficiencies span roughly 62–82% across both technologies, though individual studies report inconsistent temperature, current density, and voltage subsets (Table 1) [16,19,20,21]. Whole-plant, nuclear-integrated LTE data is scarce by comparison, only two studies were identified, at 22.9% and 37.44% system efficiency [22,23] (Table 2), neither stating an HHV/LHV basis, limiting comparability with HTSE's explicitly HHV-based figure (Table 4) [7], a limitation noted here but not resolved (Section 2.4).

Table 1. Stack-level LTE operating conditions

System/ Study	Technology	Temperature	Current Density	Cell Voltage	System Efficiency (%)	Specific Energy Consumption	Basis (HHV/LHV)
[19]	PEM	not reported	not reported	not reported	not reported	4.1–4.3 kWh/Nm ³ H ₂	Not stated
[19]	Alkaline	not reported	not reported	not reported	not reported	4.6–4.8 kWh/Nm ³ H ₂	Not stated
[20]	PEM	70 °C (optimal)	200 mA/cm ² (optimal)	not reported	67.5%	58.37 kWh/kg H ₂	Not stated
[16]	PEM	≤80–90 °C	1–3 A/cm ²	1.567 V at 1 A/cm ²	67–82%	not reported	HHV
[16]	Alkaline	not reported	0.2–0.4 A/cm ²	not reported	62–82%	not reported	HHV
[21]	PEM	80 °C	2 A/cm ²	1.9 V	65.3%	51.1 kWh/kg H ₂	Not stated
[21]	PEM	80 °C	3 A/cm ²	1.8 V	69.2%	48.2 kWh/kg H ₂	Not stated
[21]	PEM	80 °C	3 A/cm ²	1.7 V	73.2%	45.5 kWh/kg H ₂	Not stated

Table 2. Whole-plant, nuclear-integrated LTE efficiency

System/Study	Technology	Temperature	Current Density	System Efficiency	Basis (HHV/LHV)
[22] APR1400-integrated PEM electrolysis	PEM	not reported	not reported	22.9% thermal-to-hydrogen	Not stated
[23] nuclear–desalination–PEM peak-shaving system	PEM	not reported	not reported	37.44%	Not stated

2.1.2 High-Temperature Steam Electrolysis

High-temperature steam electrolysis (HTSE) operates in the 700–800 °C range (some designs up to ~850–950 °C) and achieves thermal-to-hydrogen conversion efficiencies of 50% or higher. Reactor heat generates the steam feed while reactor-generated electricity drives the electrochemical splitting step, reducing overall electrical demand relative to low-temperature electrolysis [24]. Table 3 and Table 4 summarize representative operating conditions at the stack and whole-plant scale.

Table 3. Stack-level HTSE operating conditions

System/Study	Temperature	Current Density	H ₂ Production Efficiency	Basis (HHV/LHV)
Optimized operation, early stage [25]	721.7–784.1 °C	0.8 A/cm ²	54.6–55.5%	LHV
Optimized operation, later stage [25]	~700 °C	0.59–0.70 A/cm ²	49.5–51.2%	LHV

Table 4. Whole-plant system-level HTSE efficiency (nuclear-integrated)

System/Study	Temperature	Current Density	System Efficiency	Basis (HHV/LHV)
GW-scale LWR-integrated HTSE [7]	800 °C	1.5 A/cm ²	90.2%	HHV

HTSE appears promising for large-scale nuclear hydrogen, but materials and stack lifetime still limit commercialization, especially under sustained high temperature, high current density, and transient operation; key issues include electrode instability, Ni oxidation, delamination, and thermal-cycle damage [24,25]. Compared with low-temperature electrolysis, HTSE offers higher energy-conversion efficiency because a significant fraction of the required energy is supplied as heat rather than electricity; however, long-term materials stability and stack durability remain the principal barriers to large-scale deployment.

2.1.3 Thermochemical Cycles

Thermochemical cycles split water into hydrogen and oxygen through a series of chemical reactions operating at temperatures well below the ~3000 K required for direct thermal dissociation of water [26]. The three most-studied cycles are sulfur–iodine (S-I), copper–chlorine (Cu-Cl), and hybrid sulfur (HyS), each combining thermal and (for Cu-Cl and HyS) electrochemical steps at different peak temperatures, making them suited to different reactor heat-supply capabilities [27,28,29]. Table 5 summarizes reported efficiencies and costs for all three cycles, and Table 6 compares their strengths, limitations, and nuclear-reactor compatibility. The reported cost ranges originate from studies with differing years, regions, economic assumptions, and system boundaries. They are presented to summarize the range of values reported in the literature and should not be interpreted as directly comparable cost estimates.

Table 5. Quantitative comparison of S-I, Cu-Cl, and HyS thermochemical cycles [26,30]

Cycle	Type	Peak Temperature	Typical Efficiency	Typical H ₂ Cost
S-I	Pure thermochemical	~900 °C	~35–38% (realistic); higher in optimized cases	~\$3.5–12/kg
Cu-Cl	Thermochemical/hybrid variants	~500–550 °C depending on process configuration, lower than S-I	~32–58.6%	~\$1.28–15.56/kg
HyS	Hybrid thermo-electrochemical	~700–900 °C (thermal section)	~35–48.8%	~\$2.97–9.98/kg

Note: Cost figures are drawn from studies with differing publication years, plant scales, and cost boundaries; ranges should not be interpreted as directly comparable across cycles.

Table 6. Qualitative comparison of S-I, Cu-Cl, and HyS cycles [26,30]

Cycle	Main Strength	Main Limitation	Nuclear Fit
S-I	Most extensively developed for nuclear applications	Severe corrosion and difficult acid/HI decomposition sections	Strong fit for high-temperature gas-cooled/VHTR reactors
Cu-Cl	Lower peak temperature; easier heat-source coupling	Performance depends strongly on step configuration and integration	Often considered easiest to couple with Generation IV nuclear heat
HyS	Leading sulfur-based hybrid option	Requires both thermal and electrical input	Well suited where nuclear systems can supply heat and power together

Table 5 summarizes reported efficiencies and costs for all three cycles, and Table 6 summarizes their comparative strengths, limitations, and nuclear-reactor compatibility; notably, one HTGR integration study explicitly recommended Cu-Cl over S-I under the specific plant conditions considered [27]. Sulfur-based cycles share a common sulfuric acid decomposition section, which dedicated reviews have focused on, including reactor configurations, catalytic formulations, and structural materials [31].

2.2 Techno-Economic Assessment

The case for nuclear as a hydrogen feedstock rests on the following observation: reactors run at high capacity factors, produce steady electricity, and, in several reactor classes, generate process heat that electrolyzers can use directly [32,33]. This process heat is a significant advantage. High-temperature routes consistently beat conventional electrolysis when nuclear supplies the energy: a PWR-based high-temperature electrolysis system reached 68% higher efficiency than conventional electrolysis, with a comprehensive energy recovery ratio of 17.65% [12].

HTGRs remain the most extensively studied reactor type for hydrogen cogeneration, owing to their high core-outlet temperatures (up to ~950 °C), which suit both HTSE and thermochemical cycles [24,27]. Plant scale also affects unit cost. Modeled Fischer–Tropsch e-fuel production shows the minimum fuel selling price dropping from \$3.61 per gallon at 100 MWe to \$2.66 per gallon at 1000 MWe, assuming a \$3/kg hydrogen tax credit [32], a sufficiently large difference that plant scale alone can determine project economic viability. Nonetheless, several reviews present the economics cautiously: nuclear hydrogen is generally presented as a long-term investment justified by cost trajectory, resource security, and supply reliability, rather than as the cheapest hydrogen available right now [8,33].

2.3 Environmental Assessment

Emission trends are directionally consistent across studies but vary considerably in magnitude. Every comparative life-cycle assessment reviewed here finds nuclear-based hydrogen routes emitting far less greenhouse gas than conventional, fossil-derived hydrogen [34,35,36]. The magnitude of this reduction varies considerably across studies, and much of that variation reflects differing system boundaries rather than differing pathway performance. One comparative nuclear LCA put high-temperature electrolysis at 0.4768 kg CO₂-eq per kg of hydrogen and conventional electrolysis at 0.7071 kg CO₂-eq per kg, with copper-chlorine cycle variants running noticeably higher, around 1.2 to 1.35 kg CO₂-eq per kg [35]. A broader survey of clean hydrogen pathways found the copper-chlorine cycle could reach as low as 0.86 kg CO₂-eq per kg under favorable renewable heat-and-power assumptions, compared with 7.95 kg CO₂-eq per kg for conventional hydrogen [34]. These figures are production-stage (plant-gate) estimates. A more recent full-chain PWR-HTE study, by contrast, reports 2.18 kg CO₂-eq per kg, a figure that extends past the plant gate into transport and the broader industrial chain, and is therefore not directly comparable to the plant-gate figures above [12].

Table 7. Life-cycle GHG emissions by nuclear hydrogen production pathway

Pathway	Emissions (kg CO ₂ -eq/kg H ₂)	Scope	Source
High-temperature electrolysis	0.4768	Production-stage	[35]
Conventional electrolysis	0.7071	Production-stage	[35]
Copper-chlorine cycle	1.2–1.35	Production-stage	[35]
Copper-chlorine cycle (favorable renewable heat/power)	~0.86	Production-stage	[34]
Conventional (fossil-derived) hydrogen, for reference	7.95	Production-stage	[34]
Full-chain PWR-HTE	2.18	Full-chain (includes transport, industrial chain - not just plant gate)	[12]

The dominant sources of these emissions differ by pathway. In HTGR-based assessments, electrolyzer manufacturing and spent fuel disposal dominate the footprint [36]. In the PWR-HTE study cited above, transportation alone accounted for 58.7% of global

warming potential, more than construction and operation combined [12]. This figure strongly suggests that hydrogen's climate performance depends as much on logistics as on the reactor technology itself. The choice of hydrogen source also directly shapes vehicle-level outcomes. Hydrogen fuel cell electric vehicles cut greenhouse gas emissions by 50 to 90% relative to gasoline vehicles, with the exact figure depending on the hydrogen pathway feeding the tank [9]; among the pathways assessed in whole-industry-chain FCV studies, nuclear thermochemical water splitting is the strongest performer [11].

2.4 Gaps in the Current Literature

Production-side life-cycle assessment is relatively well established for HTSE and thermochemical cycles; low-temperature electrolysis, by contrast, has received comparatively little dedicated production-cost or life-cycle treatment in the literature reviewed here (Section 2.1.1). The remaining supply chain has also received considerably less attention than production itself. Some recent studies do trace nuclear hydrogen past the plant gate; Li et al. [12] extend a PWR-HTE life-cycle assessment through transportation logistics, and Lyu et al. [11] connect hydrogen-pathway choice to full FCV life-cycle outcomes for a matched reactor-vehicle case: Li et al. [12] is environmental-only and does not extend to a specific refueling station or vehicle model, while Lyu et al. [11]'s techno-economic detail is limited relative to its environmental scope.

This gap reflects a consistent pattern in the literature: production-focused studies (Section 2.3) generally stop at the plant gate or, at most, transportation, while the vehicle-oriented literature approaches the problem from the opposite direction, emphasizing that commercial viability depends just as much on refueling cost, storage technology, fuel cell durability, and infrastructure build-out [9,10,37]. These two bodies of literature rarely combine cost and environmental accounting for the same specific configuration. The practical consequence is that nuclear hydrogen can look favorable in a plant-gate cost assessment, while its delivered, pump-level cost and the emissions associated with hydrogen delivery remain comparatively underexamined. A second, more specific gap concerns data comparability rather than coverage. Cost and emissions figures compiled across studies (e.g., the thermochemical cycle cost ranges in Table 5) are frequently presented without disclosing the underlying primary study's reference year, region, or system boundary.

This imbalance is evident when research coverage is assessed across dimensions: studies of nuclear electrolysis and thermochemical cycles cluster heavily around techno-economics and life-cycle GHG accounting; full FCV supply-chain and refueling-infrastructure studies cluster on vehicle integration and deployment; and comparatively few studies combine both for one matched configuration. National transition modeling remains under-represented across all reviewed categories.

2.5 Synthesis

This literature broadly confirms that nuclear power can produce low-carbon hydrogen; high-temperature electrolysis paired with advanced reactors, along with thermochemical cycles, most consistently emerge as strong performers on efficiency and emissions grounds [11,36]. A narrower but more consequential question remains only partly resolved: whether the delivered cost of that hydrogen, once transport distance and refueling infrastructure are priced in, can compete well enough to support fuel cell vehicles at meaningful scale [10,12,37]. To illustrate what such an analysis involves, and to make explicit where the underlying data can and cannot be harmonized, Section 4 works through one representative reactor-electrolyzer configuration and vehicle case in detail. This worked example is intended to demonstrate the method and surface data limitations, not to resolve the broader question definitively; doing so would require comparable treatment across additional reactor types, vehicle segments, and primary (rather than secondary-review) cost data.

3. Methodology

3.1 Research Design

This paper adopts an integrated case-study design in which original techno-economic and environmental modeling-production-stage greenhouse gas emissions and station dispensing cost, generated specifically for a representative HTSE-FCV configuration

using established, publicly available modeling tools (Sections 3.3–3.4) is informed and contextualized by a narrative synthesis of the existing literature. Cost, efficiency, and emissions figures for three nuclear-coupled hydrogen production pathways, low-temperature electrolysis, high-temperature steam electrolysis (HTSE), and thermochemical cycles are otherwise drawn from peer-reviewed studies, agency reports, and international assessments (IAEA, DOE, GIF/NEA) and evaluated for techno-economic and environmental performance in the specific context of hydrogen fuel cell vehicles (FCVs). Section 3.3 then applies this combined literature-derived and original data to a single, representative, internally consistent case study, illustrating how production-level figures translate into vehicle-relevant outcomes; this case study is intended to demonstrate the method and surface data limitations rather than to resolve the broader techno-economic question definitively (Section 2.5).

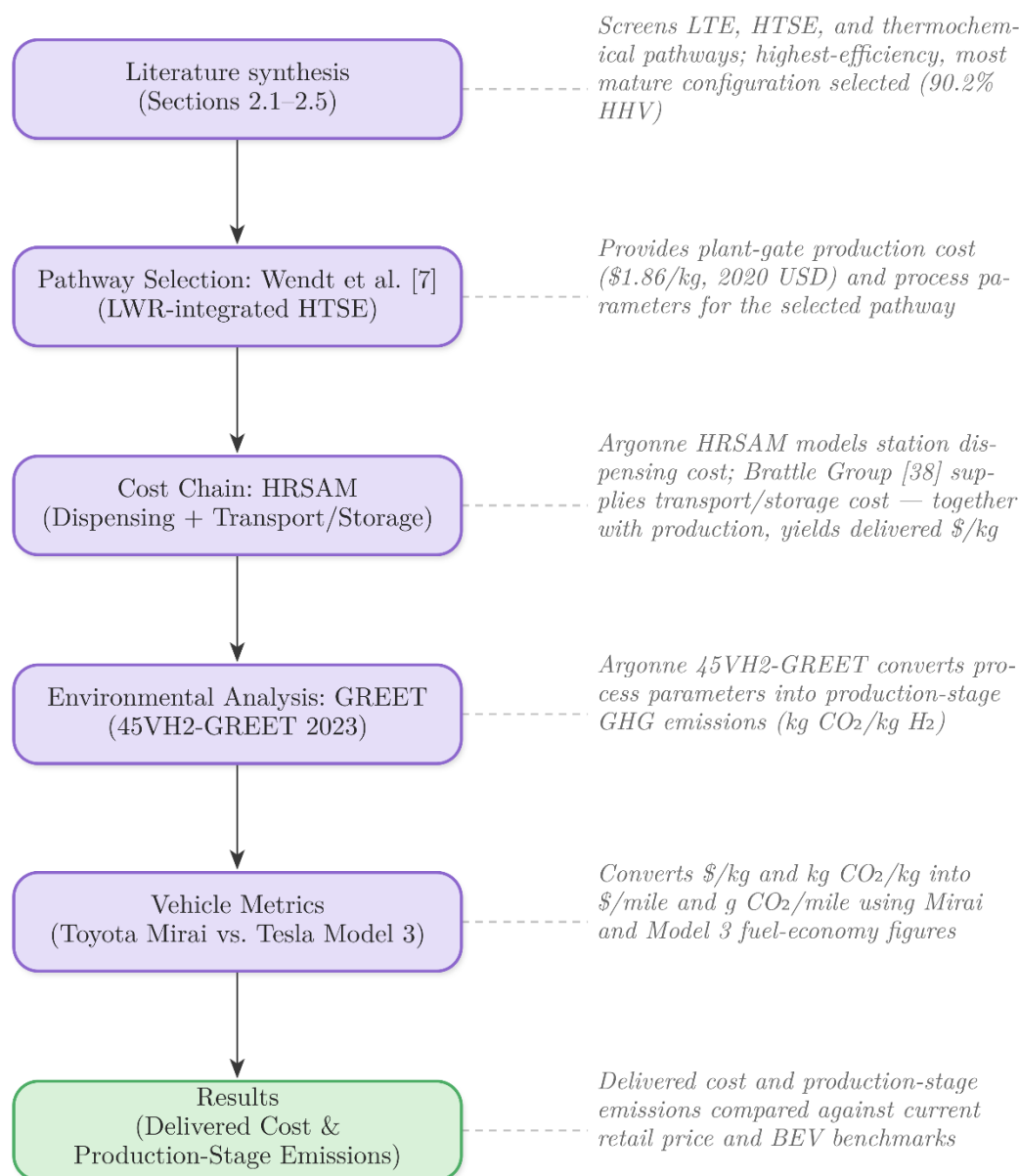


Figure 1. Methodological workflow adopted in this study, illustrating the integration of literature synthesis with representative case-study analyses for techno-economic and environmental evaluation of nuclear-produced hydrogen for FCVs

3.2 Data Collection Framework

Sources were identified through a narrative review process rather than a fixed, systematic-review protocol (e.g., PRISMA); this review does not claim systematic completeness, though efforts were made to ensure a comprehensive and balanced selection of relevant literature within this scope. The literature search was conducted between July 2026 and August 2026. Literature identification combined manual search through Google Scholar with AI-assisted literature discovery using Consensus, an academic search platform built on the Semantic Scholar corpus, using search strings combining terms such as ("nuclear hydrogen production" OR "high-temperature steam electrolysis" OR "thermochemical water splitting") AND ("techno-economic analysis" OR "life-cycle assessment") AND ("fuel cell vehicle" OR "hydrogen refueling infrastructure"). Titles and abstracts were screened for relevance and limited to English-language, peer-reviewed journal articles and major agency reports (IAEA, DOE, GIF/OECD-NEA), followed by full-text review of selected sources; reference lists of included articles were also reviewed to identify additional relevant studies (citation tracing). Sources surfaced by Consensus were independently retrieved and read in the original peer-reviewed source or report before inclusion, rather than relied upon via Consensus's AI-generated summary.

Sources were further restricted to those published in 2020 or later to maintain comparability across the nuclear fuel cycle's technological vintage, enrichment method, reactor capacity factor, and background grid composition, and to limit the range of currency/price levels requiring inflation adjustment (Section 3.3). We retain foundational references describing established electrolysis or thermochemical-cycle chemistry regardless of publication date, as this material describes fixed chemical and physical principles rather than time-sensitive performance data. Older techno-economic studies are likewise retained where cited only as a historical benchmark against which more recent, harmonized cost estimates are compared, rather than as primary data feeding into this study's own harmonized figures.

A source was qualified for inclusion if it reported quantitative information on production cost, energy efficiency, operating conditions, hydrogen output, or life-cycle greenhouse gas emissions for nuclear-coupled hydrogen production systems. Studies focusing exclusively on non-nuclear hydrogen pathways were included only when they provided relevant comparative benchmarks, such as conventional steam methane reforming (SMR), renewable electrolysis, or battery electric vehicles (BEVs). No additional numerical exclusion criteria were applied. When multiple studies reported values at different system scales (e.g., stack-level, plant-level, or fuel-cycle level), those distinctions were preserved rather than averaged, ensuring that comparisons remained consistent with the original system boundaries and assumptions reported by each source.

The final reference list included 47 sources. Consistent with the date restriction described above, 39 dated sources were published in 2020 or later; one earlier source [38] was retained under the exceptions noted above, and three institutional web pages are undated [3–5]. This review does not report full database-level search statistics (number of records initially identified, duplicates removed, or records excluded at each stage), consistent with its narrative rather than systematic design.

3.3 Techno-Economic Assessment Method

The techno-economic assessment compares levelized cost of hydrogen (LCOH, in USD/kg) across the three nuclear-coupled pathways, drawing on cost ranges compiled from the literature where available - most comprehensively for thermochemical cycles (Table 5); comparable literature-compiled cost ranges for LTE and HTSE are considerably sparser, a gap noted in Section 2.4. Cost figures were harmonized to a common reference year of June 2026 using the U.S. Bureau of Labor Statistics CPI-U (All Items, U.S. city average, not seasonally adjusted; series CUUR0000SA0) [39], where the underlying primary source's publication year and currency basis were individually traceable; where cost ranges were compiled within secondary reviews whose underlying primary-study years are not individually recoverable (Table 5), this limitation is noted explicitly (Section 2.4). Each input cost was converted individually to June 2026 USD before combination, using the annual-average index for its reporting year (240.007 for 2016, 258.811 for 2020, and 313.689 for 2024) and the June 2026 monthly index (333.952). This yields harmonization factors of $\times 1.3914$ (2016→June 2026), $\times 1.2904$ (2020→June 2026), and $\times 1.0646$ (2024→June 2026), applied respectively to the HRSAM default cost basis, the Wendt et al. plant-gate cost, and the Brattle Group transportation and storage costs prior to summation. Tables 1–4 present the corresponding range of reported efficiency values across the literature.

The Wendt et al. (2022) LWR-integrated HTSE configuration was selected as the representative case study primarily because it provides a complete and internally consistent dataset suitable for the harmonized cost and emissions treatment adopted in this study. The study reports detailed capital and operating cost data, process-level electricity and thermal requirements, operating conditions, and sensitivity results, allowing harmonization to a common reference year and evaluation using the Argonne 45VH2-GREET 2023 framework. The selection therefore relied primarily on data completeness and methodological compatibility rather than reported cost or efficiency. Nevertheless, the Wendt configuration represents a favorable, GW-scale NOAK (n-th-of-a-kind) scenario: the source reports a whole-plant efficiency of 90.2% on an HHV basis and a base-case LCOH of \$1.86/kg at an electricity price of \$30/MWh, while explicitly describing the constant-production configuration as a bounding or limiting scenario. These characteristics mean the selected configuration should not be interpreted as representative of the full range of possible LWR–HTSE performance, and its reported efficiency and production cost likely lie toward the more optimistic end of the performance range reported in the literature. Accordingly, we interpret the results from this configuration as scenario-specific estimates rather than representative values for all LWR-integrated HTSE systems. As an additional economic robustness check, the less-favorable individual-parameter sensitivity reported by Wendt et al. is considered in the Results section to illustrate the sensitivity of the production cost to the underlying economic assumptions [7].

The representative case study presented in this section employs a single, internally consistent source chain based on the HTSE reference design reported by Wendt et al. Published capital, operating, and hydrogen production data are harmonized to a common reference year before calculating plant-gate hydrogen production cost. Downstream transportation and storage costs are incorporated using published cost data [40], similarly harmonized. Transportation and storage cost estimates from Brattle Group (2024) [40] correspond to the report's compressed gaseous hydrogen trucking scenario for distances under 150 miles, consistent with this case study's tube-trailer-supplied station configuration. This scenario assumes compressed gaseous trailers with a capacity of approximately 560–900 kg H₂, compressed to above 180 bar (2,600 psig) for road transport. Storage cost assumptions correspond to above-ground compressed-gas storage, modeled in the source report at approximately 500 bar. The source report does not specify payload utilization, return-trip logistics, fuel consumption, hydrogen losses in transit, or loading/unloading time assumptions underlying its cost estimates; these parameters are therefore inherited as embedded assumptions within the Brattle Group figure rather than independently verified or modeled in this study. Station dispensing cost was calculated using the Hydrogen Refueling Station Analysis Model (HRSAM), Version 2.0, developed by Argonne National Laboratory with support from the U.S. Department of Energy [41]. The modeled station uses gaseous hydrogen supplied by tube trailer and cascade dispensing at a vehicle service pressure of 700 bar, with a design capacity of 600 kg H₂/day and thermal-buffering precooling. The station configuration includes four hoses and four dispensers, a five-minute vehicle filling time, a two-minute vehicle lingering time, a maximum dispensed quantity of 5 kg H₂ per vehicle, one main compressor operating with two compression stages, no booster compressor, and an isentropic compressor efficiency of 75%. Hydrogen loss during compression is set at 0.5%. HRSAM economic inputs use a 2016-dollar cost basis, a 10% real after-tax discount rate, a 10-year analysis period, a 1.9% inflation rate, and an electricity price of \$0.12/kWh. Station utilization was varied across 25%, 40%, 60%, and 80%, with the resulting dispensing costs harmonized to June 2026 USD using the CPI-U methodology described above; the corresponding results are reported in Table 8. For each utilization level, HRSAM Version 2.0 was evaluated under three production-volume scenarios designated Low, Mid, and High. These scenarios represent progressively greater component-cost maturity and production-volume effects within the HRSAM model: the Low scenario uses the reference component-cost assumptions, while the Mid and High scenarios apply progressively greater component-cost reductions according to the model's technology-experience categories. Thus, Low, Mid, and High do not represent different station capacities or hydrogen-production processes; they represent alternative component-cost maturity assumptions within the same modeled station configuration. All utilization cases (25%, 40%, 60%, and 80%) and all three component-maturity cases (Low, Mid, and High) were generated by the authors by running HRSAM Version 2.0 with the inputs listed above; they are not taken from any published source.

To assess what production cost means in practice for FCV users, LCOH values are translated into vehicle-relevant metrics using the Toyota Mirai as a reference case (fuel economy $\approx$ 71.8 mi/kg, tank capacity 5.6 kg H₂, 2026 model year) [42], matched to the same model year as the representative BEV (Section 3.4), following Equations 1–3:

$$\text{Cost per mile (\$/mi)} = \text{LCOH (\$/kg)} \div \text{Fuel economy (mi/kg)} \quad (1)$$

$$\text{Cost per fill (\$)} = \text{LCOH (\$/kg)} \times \text{Tank capacity (kg)} \quad (2)$$

$$\text{Range per fill (mi)} = \text{Fuel economy (mi/kg)} \times \text{Tank capacity (kg)} \quad (3)$$

These calculations are applied at two levels: (i) using the plant-gate production cost reported in the case-study source [7], and (ii) using a delivered (pump) cost incorporating transportation and storage [40] and station dispensing calculated for this study using Argonne National Laboratory's Hydrogen Refueling Station Analysis Model (HRSAM), with all three cost components harmonized to a common reference year. This distinction is necessary because reported LCOH values frequently represent production-stage cost only and exclude downstream supply-chain costs, as detailed earlier in this section.

3.4 Environmental Assessment Method

The environmental assessment combines a comparative review of published greenhouse gas (GHG) emissions across varying system boundaries with an original well-to-gate emissions assessment of the representative HTSE case study. Published emissions data for low-temperature electrolysis, high-temperature steam electrolysis, and thermochemical hydrogen production pathways were compiled from recent peer-reviewed studies and international agency reports (Table 7). Because reported emissions depend strongly on system boundaries (e.g., production-stage, well-to-gate, or well-to-wheel), values were compared only within equivalent assessment boundaries rather than averaged across studies.

Environmental Assessment Using 45VH2-GREET. The production-stage greenhouse-gas emissions of nuclear hydrogen were evaluated using the U.S. Department of Energy/Argonne National Laboratory 45VH2-GREET 2023 model (December 2023 release) [43] under a well-to-gate system boundary. The High-temperature electrolysis (Nuclear) pathway was selected with a technology share of 100%. The process inputs were 36.8 kWh electricity/kg H₂ and 0.02184 MMBtu thermal energy/kg H₂, based on the reference configuration reported by Wendt et al. (2022) [7]. Hydrogen production was specified at 290 psia, with no oxygen coproduct credit. All other model inputs and settings were retained at their default values. The model was run using a 2026 simulation year to align the environmental assessment with the 2026 reference year used in the techno-economic assessment and vehicle comparison. The 2023 model release was retained to maintain consistency with the GREET 2023 electricity-emission factors used for the comparative BEV assessment. The model's emissions output provided the total well-to-gate greenhouse-gas intensity in g CO₂-eq/MMBtu H₂ on an LHV basis, which was converted to kg CO₂-eq/kg H₂ using the GREET hydrogen LHV basis of 120 MJ/kg H₂.

The selected nuclear pathway includes the upstream emissions associated with the nuclear electricity supply within the GREET fuel-cycle framework. Accordingly, the resulting value represents the production-stage well-to-gate greenhouse-gas intensity of hydrogen, rather than direct facility emissions alone.

The resulting plant-gate greenhouse-gas emissions are reported as kg CO₂-eq/kg H₂. To evaluate their implications for transportation applications, production-stage emissions are converted into vehicle-specific emissions using the representative Toyota Mirai fuel economy according to Equation (4):

$$\text{Production-stage emissions, FCV (g CO}_2\text{-eq/mi)} = \text{Production emissions (kg CO}_2\text{-eq/kg H}_2\text{)} \div \text{Fuel economy (mi/kg H}_2\text{)} \times 1000 \quad (4)$$

where the Toyota Mirai fuel economy is approximately 71.8 mi/kg H₂, and the factor of 1000 converts kilograms of CO₂-equivalent emissions to grams.

For comparison, we estimated representative battery electric vehicle (BEV) emissions from the fuel-cycle greenhouse-gas emissions associated with electricity supply. The GREET 2023 model developed by Argonne National Laboratory was used to obtain electricity fuel-cycle emission factors. For the U.S. average electricity mix, GREET 2023 reports total fuel-cycle emissions of 128,805 g CO₂-eq /mmBtu of electricity available at the user site, corresponding to 439.6 g CO₂-eq/kWh. For the LWR nuclear-

electricity scenario, the GREET 2023 nuclear pathway reports total fuel-cycle emissions of 809.97 g CO₂-eq/mmBtu, equivalent to 2.76 g CO₂-eq/kWh.

$$\text{Grid-supply emissions, BEV (g CO}_2\text{-eq/mi)} = \text{Grid emissions intensity (g CO}_2\text{-eq/kWh)} \times \text{Vehicle energy consumption (kWh/mi)} \quad (5)$$

The electricity consumption of the 2026 Tesla Model 3 Standard Rear-Wheel Drive (RWD) was taken as 0.24 kWh/mile (24 kWh/100 miles; 139 MPGe combined), based on the EPA fuel-economy rating reported on FuelEconomy.gov [44]. This EPA-rated value represents energy drawn from the electrical outlet and therefore includes charging losses; it is used as a wall-to-vehicle electricity-consumption value rather than battery-only energy consumption. Electricity emission factors were obtained from the GREET 2023 model on a fuel-cycle basis, expressed per kWh of electricity delivered. The U.S. average electricity pathway represents the national-average electricity mix, while the light-water-reactor (LWR) pathway represents the nuclear-electricity scenario. Section 4 calculated the resulting electricity-related emissions using Equation (5).

4. Results

Prior to analysis, cost and efficiency data compiled from the literature (Tables 1–5) were checked for basis-year and system-boundary consistency, as described in Section 3.3. Where values were reported at different scales (stack-level versus system-level) or under different cost bases, this was noted rather than merged. For the case study specifically, the plant-gate production cost of \$1.86/kg (2020 USD) reported for the NOAK LWR-HTSE configuration [7] was harmonized to a June 2026 USD basis using BLS CPI-U data (index level 333.952, June 2026; 258.811, 2020 annual average), then combined with transportation and storage cost data [40], both similarly harmonized, and an original station dispensing cost calculated for this study using Argonne's HRSAM model, to construct an internally consistent delivered-cost estimate on a single reference-year basis.

The Wendt et al. (2022) HTSE plant is a gigawatt-scale centralized production facility with a design capacity of 611 tonnes/day of actual hydrogen production. This study does not assume that a single such plant supplies a single 600 kg/day station. Instead, the Wendt plant serves only as a techno-economic reference for the production-stage unit cost (\$/kg H₂). This unit cost is specific to the reference plant's design scale, utilization, and other assumptions and is not assumed to transfer to other plant sizes or operating conditions. The downstream delivery chain-transportation, storage, and dispensing, is modeled separately for a representative 600 kg/day retail station, consistent with the station capacities analyzed in the HRSAM literature [40]. In design-capacity terms, the 611 tonnes/day plant output is equivalent to approximately 1,018 stations of 600 kg/day capacity (611,000 kg/day ÷ 600 kg/day). At the base-case station utilization of 40%, however, each station dispenses approximately 240 kg/day (600 kg/day × 0.40), so the same plant output would supply approximately 2,546 stations (611,000 kg/day ÷ 240 kg/day). The two figures are not interchangeable: the former is a design-capacity equivalence, and the latter reflects actual throughput. The station therefore represents one node in a larger network, not a standalone system supplied directly by the plant. This allocation logic ensures transportation and storage costs are calculated per station, consistent with the scale of the overall production system.

Applying the vehicle-level cost translation established in Section 3.3 (Equations 1–3) to the representative FCV (Toyota Mirai, 71.8 mi/kg, 5.6 kg tank) using the harmonized plant-gate production cost of \$2.40/kg yields a cost of \$0.033/mile and a full-fill cost of \$13.44, over a range of approximately 402 miles. When transportation, storage, and station dispensing costs are incorporated, the estimated delivered cost rises to \$13.76–22.22/kg, corresponding to \$0.192–0.310/mile and a fill cost of \$77.06–124.43. For comparison, reported retail hydrogen pricing in California was \$34–36/kg in October 2024 [45] (a monthly average of \$34.55/kg, with the largest station operator at \$36/kg), corresponding to \$0.474–0.501/mile and a fill cost of \$190.40–201.60. This is a dated benchmark, not a current 2026 market price: no more recent (2025–2026) retail price assessment could be identified for this comparison, and the light-duty FCV retail segment has contracted substantially since that figure was recorded. Relative to this October 2024 benchmark, the nuclear-HTSE delivered-cost estimate represents a reduction of roughly 35–62%. In addition, retail hydrogen prices in California rose substantially over the preceding three years, from approximately \$16/kg in September 2021 (implied by the reported 119% increase to the October 2024 level) to \$34.55/kg in October 2024 [45], cited here only to establish this historical trend, not as a current-year point estimate, moving in the opposite direction from earlier industry cost-reduction projections and underscoring the potential value of a lower-cost, nuclear-coupled pathway.

Wendt et al. [7] also report the effect of a single isolated change: reducing the assumed electricity price from \$30/MWh-e to \$20/MWh-e alone lowers the LCOH to \$1.45/kg (2020 USD), or \$1.87/kg harmonized to June 2026 USD, showing that electricity price alone accounts for roughly two-thirds of the total cost reduction achieved in the fully "aggressive" scenario below.

Wendt et al. [7] additionally report a combined "aggressive" scenario - incorporating a lower electricity price (\$20/MWh-e), reduced capital cost, reduced fixed operating costs, extended stack service life, and increased capacity factor - that achieves an LCOH of exactly \$1.00/kg in 2020 dollars, matching the DOE Hydrogen Shot ultimate target of \$1/kg. Harmonized to a June 2026 USD basis using the same CPI factor applied elsewhere in this section ($\times 1.2904$), this scenario corresponds to \$1.29/kg - meaning that under consistent, inflation-adjusted terms, the "aggressive" scenario's headline achievement of the \$1/kg target does not hold once cost figures are harmonized to a common present-day basis, though it remains substantially below both the baseline case-study cost and current retail pricing.

As a less-favorable sensitivity, the upper-end electricity-price condition in the Wendt et al. [7] analysis increases the LCOH from the \$1.86/kg base case to \$2.27/kg (2020 USD). Using the same CPI harmonization factor applied elsewhere in this study ($\times 1.2904$), this corresponds to approximately \$2.93/kg in June 2026 USD. At the representative Toyota Mirai fuel economy of 71.8 mi/kg H₂, this production cost corresponds to approximately \$0.041/mile and a full-fill cost of approximately \$16.40. This sensitivity shows that the favorable \$2.40/kg harmonized case-study result depends on the underlying economic assumptions, particularly electricity price, and should not be interpreted as a universal LWR-HTSE production cost.

The 45VH₂-GREET 2023 simulation [43] for the nuclear high-temperature electrolysis pathway, using the process parameters of Wendt et al. [7], resulted in zero direct facility CO₂ emissions and 843 g CO₂/MMBtu H₂ of indirect CO₂ emissions. Including all greenhouse gases, the total production-stage intensity was 915 g CO₂-eq/MMBtu H₂. Using the GREET lower heating value (LHV) of 120 MJ/kg H₂, this corresponds to approximately 0.10 kg CO₂-eq/kg H₂. The indirect emissions arise from the upstream supply of the nuclear electricity and thermal energy represented in the GREET fuel-cycle pathway, and the difference between the CO₂-only value (843 g) and the total (915 g CO₂-eq) reflects the contribution of non-CO₂ greenhouse gases converted to CO₂-equivalents.

Based on the representative Toyota Mirai fuel economy of 71.8 mi/kg H₂, production-stage hydrogen emissions correspond to approximately 0.0014 kg CO₂-eq/mi (1.4 g CO₂-eq/mi), calculated using Equation (4). This value represents emissions associated with hydrogen production and upstream electricity supply within the well-to-gate boundary and does not include downstream hydrogen transport, dispensing, vehicle operation, or other well-to-wheel stages. It is substantially below the general literature range for HTE-type pathways reported in Table 7, most likely reflecting GREET's treatment of nuclear-sourced electricity as a near-zero-carbon input.

Applying Equation 5, a representative BEV (Tesla Model 3, 2026, 0.24 kWh/mi) operating on the U.S. average electricity mix produces approximately 105.5 g CO₂-eq/mile, based on the GREET 2023 fuel-cycle emission factor of 439.6 g CO₂-eq/kWh. Under the nuclear-electricity scenario, represented by the GREET 2023 LWR nuclear pathway with a fuel-cycle emission factor of 2.76 g CO₂-eq/kWh, the same vehicle produces approximately 0.66 g CO₂-eq/mile. These results provide a consistent fuel-cycle basis for comparing the electricity-related emissions of the two BEV electricity-supply scenarios.

A notable finding was the scale of the gap between plant-gate and delivered cost: in the 40% utilization base case, incorporating transportation, storage, and station dispensing costs increased the estimated cost per mile by a factor of approximately 5.7–9.3, narrowing, though not eliminating, the cost advantage of nuclear-coupled HTSE relative to the October 2024 retail benchmark. Station dispensing is the largest single cost component in every utilization and scenario combination in Table 8 (25–80% utilization; Low, Mid, and High). Across all twelve combinations, dispensing cost (\$5.27–27.88/kg) exceeds the combined production, transportation, and storage cost (\$3.57–4.63/kg), even at its lowest value (80% utilization, High scenario). In the 40% base case alone, dispensing costs \$10.19–17.59/kg. This range reflects real variability in station configuration and utilization, not measurement uncertainty.

Table 8. Delivered-cost component breakdown by station utilization and HRSAM component-cost scenario (harmonized, June 2026 USD; base case = 40% utilization)

Utilization	Scenario	Production (\$/kg)	Transportation (\$/kg)	Storage (\$/kg)	Dispensing (\$/kg)	Total Delivered Cost (\$/kg)
25%	Low	2.40	0.96–2.02	0.21	27.88	31.45–32.51
	Mid	2.40	0.96–2.02	0.21	17.56	21.13–22.19
	High	2.40	0.96–2.02	0.21	16.04	19.61–20.67
40% (base case)	Low	2.40	0.96–2.02	0.21	17.59	21.16–22.22
	Mid	2.40	0.96–2.02	0.21	11.13	14.70–15.76
	High	2.40	0.96–2.02	0.21	10.19	13.76–14.82
60%	Low	2.40	0.96–2.02	0.21	11.84	15.41–16.47
	Mid	2.40	0.96–2.02	0.21	7.54	11.11–12.17
	High	2.40	0.96–2.02	0.21	6.90	10.47–11.53
80% (HRSAM baseline)	Low	2.40	0.96–2.02	0.21	8.98	12.55–13.61
	Mid	2.40	0.96–2.02	0.21	5.75	9.32–10.38
	High	2.40	0.96–2.02	0.21	5.27	8.84–9.90

Note: Base case: 40% utilization. Low/Mid/High are HRSAM component-cost maturity scenarios for the same 600 kg/day station (Section 3.3), not different capacities. The \$13.76–22.22/kg range in the text is the 40% base case. Dispensing costs were calculated using HRSAM Version 2.0 (U.S. DOE). Key model inputs: gaseous H₂, tube-trailer supply, cascade dispensing at 700 bar, 600 kg/day design capacity, thermal-buffering precooling, 4 hoses/4 dispensers, 5-min fill time, 2-min lingering time, 5 kg max H₂ per vehicle, 1 main compressor (2 stages, no booster, 75% isentropic efficiency), 0.5% compression loss, 2016 USD cost basis, 10% real after-tax discount rate, 10-year analysis period, 1.9% inflation, \$0.12/kWh electricity price.

Production cost is the harmonized plant-gate cost from Wendt et al. (2022) [7]; transportation and storage costs are from Brattle Group (2024) [40], harmonized to June 2026 USD. This study calculated dispensing costs using Argonne National Laboratory's HRSAM model at multiple utilization levels (25%, 40%, 60%, and 80%) and three production-volume/component-maturity scenarios (Low, Mid, High). The 40% utilization case is adopted as the base case, reflecting an optimistic near-term scenario for passenger FCV refueling.

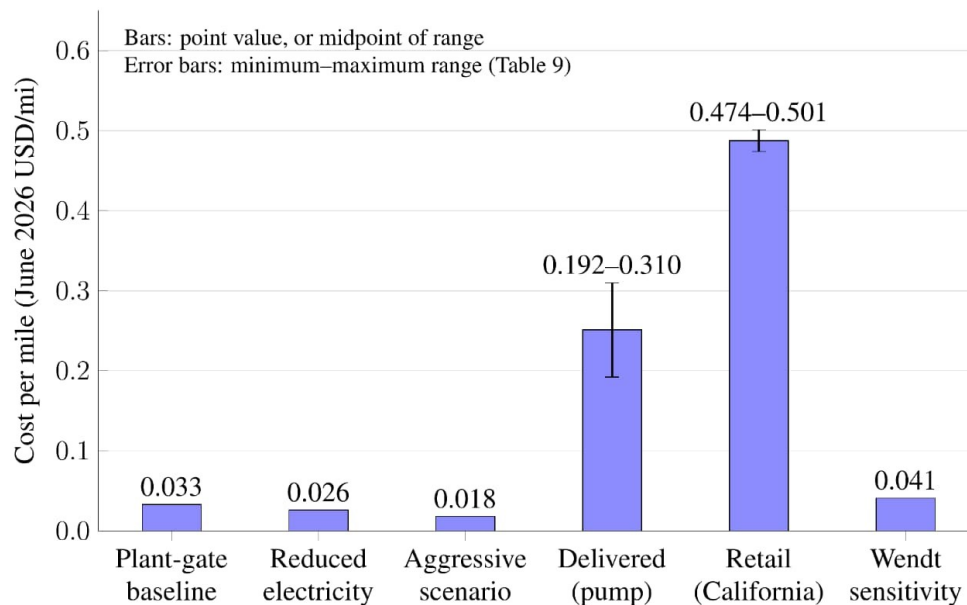
**Figure 2.** Cost per mile across cost bases for the case study, including the plant-gate baseline, the Wendt et al. single-variable and aggressive-scenario sensitivities, the delivered (pump) cost, and current California retail pricing. Error bars denote the reported range.

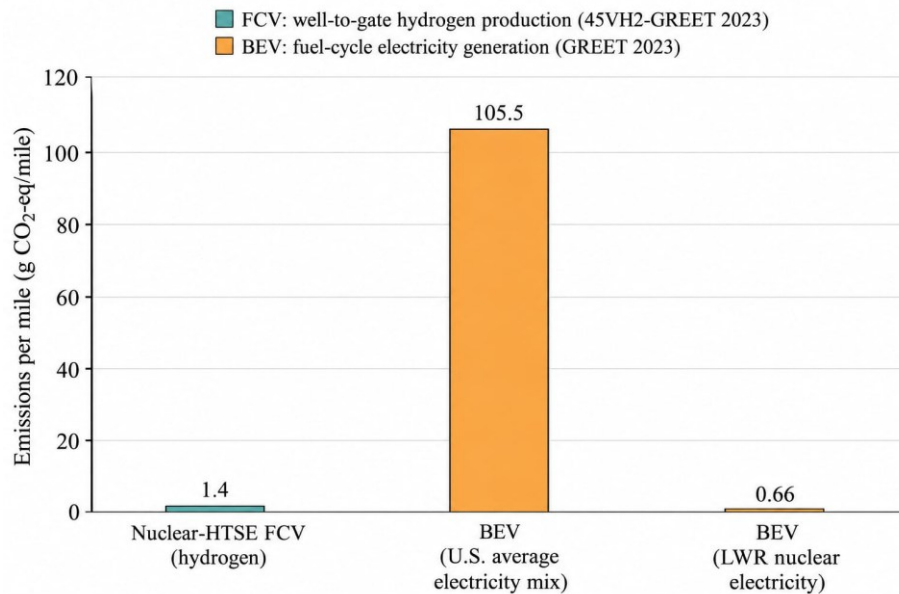
Table 9. Case study cost results across cost bases (June 2026 USD)

Cost Basis	LCOH (\$/kg)	Cost/mile (\$/mi)	Cost/fill (\$)
Plant-gate production, baseline	2.40	0.033	13.44
Plant-gate, reduced electricity price only (\$20/MWh-e)	1.87	0.026	10.47
Plant-gate, aggressive combined scenario	1.29	0.018	7.22
Delivered (production + transport + storage + dispensing)	13.76–22.22	0.192–0.310	77.06–124.43
Current market retail (California, October 2024) [45]	34–36	0.474–0.501	190.40–201.60
Wendt less-favorable electricity-price sensitivity	2.93	0.041	16.40

Table 10. Fuel-related emissions per vehicle-mile, FCV vs. BEV case study (different system boundaries)

Pathway	Scope	Electricity/fuel-cycle emissions factor	Production-stage emissions (g CO ₂ -eq/vehicle-mile)	Source
Nuclear-HTSE FCV (case study)	Well-to-gate (production)	0.10 kg CO ₂ -eq/kg H ₂	1.4	45VH2-GREET 2023 (this study)
BEV, U.S. average electricity mix	Fuel-cycle electricity	439.6 g CO ₂ -eq/kWh	105.5	GREET 2023 (this study)
BEV, nuclear LWR electricity	Fuel-cycle electricity	2.76 g CO ₂ -eq/kWh	0.66	GREET 2023 (this study)

Note: The FCV value covers hydrogen production only, up to the plant gate; hydrogen transport, storage, dispensing, and vehicle-cycle emissions are not included. The BEV values cover fuel-cycle electricity emissions up to the delivered electricity used by the vehicle (0.24 kWh/mile, including charging losses; Section 3.4); vehicle-cycle emissions (manufacturing, battery) are not included. The boundaries therefore differ, and the values should not be read as a like-for-like vehicle life-cycle comparison.

**Figure 3.** Production-Stage Emission comparison: nuclear-HTSE FCV (production-stage basis, 45VH2-GREET 2023) versus BEV on a national-average grid and a nuclear-dominant grid.

Because these literature-compiled figures span different reference years, plant scales, and cost boundaries (Table 5; Section 2.1.3), they are reported here only to illustrate the breadth of the published range, not as a benchmark against the case study. With that caveat, reported costs span approximately \$1.28–15.56/kg (Cu-Cl), \$3.5–12/kg (S-I), and \$2.97–9.98/kg (HyS). The case study configuration (\$2.40/kg harmonized plant-gate; 90.2% HHV system efficiency) falls toward the lower-cost, higher-efficiency end of the compiled literature range, consistent with its selection as a representative, near-term feasible configuration (Section 3.3).

5. Discussion

5.1 The Infrastructure Bottleneck: From Plant-Gate to Pump

One of the clearest patterns in this analysis is how much cost accumulates between the plant gate and the pump. Nuclear-coupled HTSE reaches a harmonized plant-gate production cost of \$2.40/kg (June 2026 USD), yet the estimated delivered cost climbs to \$13.76–22.22/kg, roughly 5.7 to 9.3 times higher in the 40% utilization base case. This gap is consistent with trends suggested but rarely quantified in the literature: production studies tend to stop at the plant gate, leaving out the downstream stages that ultimately set the price paid by the consumer.

Station-level dispensing, calculated for this study using Argonne's HRSAM model (Section 3.3), accounts for the largest single share of that gap in the base-case (40% utilization) scenario (\$10.19–17.59/kg), consistently exceeding the combined production and transport/storage components (\$3.57–4.63/kg) even at its lowest cost-maturity assumption (across all modeled utilization levels, dispensing cost ranges more broadly, from \$5.27–27.88/kg), a real, single-methodology range reflecting genuine variability in component manufacturing maturity, exceeding the older but still-cited Reddi et al. (2017) [38] light-duty estimate of \$9.54/kg (harmonized), underscoring how sensitive delivered cost is to station utilization assumptions. Even if nuclear production hits the DOE's Hydrogen Shot target of \$1/kg, retail prices for FCV owners will remain high unless compression, cooling, and dispensing infrastructure improve substantially, and as shown in Section 4, this holds even in the aggressive combined cost scenario, which itself falls short of \$1/kg once harmonized to a consistent reference year.

5.2 Comparative Economic Viability

Even with these delivery costs, nuclear-produced hydrogen still undercuts the market by a wide margin, based on the most recent verifiable retail pricing data available: the estimated delivered cost of \$13.76–22.22/kg is approximately 35–62% below the \$34–36/kg range reported for California retail hydrogen in October 2024 [45], though no more recent (2025–2026) retail price assessment could be identified for this comparison, and the light-duty FCV retail segment has contracted substantially since that figure was recorded, this comparison should therefore be read as indicative of the general order of magnitude involved, rather than as a precise current-market comparison.

That gap between infrastructure-level cost modeling and what stations charge merits further examination. It points to local supply constraints and low-volume, pilot-scale station operations as a plausible driver of today's retail pricing, rather than any fundamental limit in the underlying technology. Large-scale nuclear production could reduce this gap by supplying the continuous, base-load output needed to capture the economies of scale seen in the literature, where scaling plant size from 100 MWe to 1000 MWe meaningfully lowers the minimum fuel selling price [32]

The economic result is also sensitive to the assumptions underlying the selected Wendt configuration. The Wendt et al. [7] sensitivity analysis increases the LCOH from the base value of \$1.86/kg to \$2.27/kg under less-favorable individual parameter conditions; harmonized to June 2026 USD, this corresponds to approximately \$2.93/kg. Although this remains below the recent retail benchmark considered above, it demonstrates that the favorable production-cost result is sensitive to electricity price and other economic assumptions. The \$2.40/kg case-study value should therefore be interpreted as a configuration-specific estimate rather than as a universal production cost for LWR-integrated HTSE.

5.3 The Environmental Trade-off: FCV vs. BEV

The apparent environmental performance of an FCV depends heavily on how the comparison is framed. Well-to-gate production emissions for the nuclear-HTSE case study, evaluated using Argonne's 45VH2-GREET 2023 calculator, translate to production-stage emissions of approximately 1.4 g CO₂-eq per vehicle-mile.

The comparison against battery electric vehicles is sensitive to the electricity supply pathway. Using GREET 2023 fuel-cycle emission factors, a BEV operating on the U.S. average electricity mix produces approximately 105.5 g CO₂-eq/mile, while the same vehicle under the LWR nuclear-electricity scenario produces approximately 0.66 g CO₂-eq/mile. These results demonstrate that the electricity pathway is a major determinant of BEV electricity-related emissions. However, the FCV value of 1.4 g CO₂-eq/mile represents hydrogen production-stage emissions, whereas the BEV values represent electricity-related fuel-cycle emissions. Therefore, these values should not be interpreted as a fully harmonized vehicle-level life-cycle comparison. The results nevertheless demonstrate the importance of clearly defining system boundaries and energy-supply assumptions when comparing hydrogen fuel-cell and battery-electric transportation pathways, consistent with the broader literature discussed in Section 2.3.

5.4 Limitations

Several data limitations bear on how the findings above should be read.

Emissions scope: The case study's original GHG emissions calculation is well-to-gate (0.10 kg CO₂-eq/kg H₂; Section 3.4 and 4), not full-chain. The broader literature indicates transportation can account for the majority of full-chain life-cycle emissions in comparable systems [12]. Because the FCV value remains a production-stage result, this study does not determine whether the apparent emissions advantage relative to the U.S. average-grid BEV would persist after hydrogen transportation, storage, compression, and dispensing emissions are incorporated for the specific case-study configuration (Section 2.3).

Compression emissions boundary: The case study's well-to-gate emissions figure (0.10 kg CO₂-eq/kg H₂; Section 3.4 and 4) reflects hydrogen at the plant's output pressure (290 psia) and does not include emissions from compressing hydrogen to the 700 bar required for vehicle dispensing. Given that compression is consistently identified in the current literature as the largest single contributor to compression-storage-dispensing (CSD) cost, at 55-65% [46], the full-chain emissions associated with hydrogen delivery and vehicle refueling would likely be higher than the production-stage value reported here - a gap this study does not resolve.

Efficiency basis: Two LTE studies cited in this review [22,23] do not state whether reported system efficiency is on a higher (HHV) or lower (LHV) heating-value basis, limiting direct comparability with the case study's explicitly HHV-based HTSE efficiency (Section 2.1.1).

Retail price currency: The market-price comparison relies on California retail data from October 2024 [45]; no 2025-2026 retail assessment could be identified despite a dedicated search (Section 5.2), and the underlying market segment has since contracted substantially.

Dispensing cost precision: The original HRSAM-derived dispensing cost spans \$10.19-17.59/kg (Section 3.3, 4), reflecting genuine sensitivity to station configuration and component-cost maturity assumptions rather than measurement error - though this range is wide enough that it should be treated as bounding, not a precise point estimate.

Base-load production assumption: The case study's production cost is based on a continuous, fixed-price electricity input [7] rather than a flexible dispatch model that would allow the reactor to sell electricity to the grid during high-price periods instead of producing hydrogen. This opportunity cost is not captured in the reported LCOH, and recent literature on flexible nuclear-

hydrogen operation suggests it could be economically significant; addressing it would require a dynamic dispatch model beyond this study's scope

Production-scale allocation: The Wendt plant is used only as a cost reference, not as the direct hydrogen source for the modeled station. The \$2.40/kg plant-gate cost reflects that plant's gigawatt-scale design, utilization, and other assumptions (Section 3.3); unit production cost varies with plant scale and operating assumptions even when expressed per kilogram, so this result should not be transferred to smaller plants or different operating conditions. The plant-to-station equivalence (approximately 1,018 stations at design capacity, or approximately 2,546 at 40% station utilization) is a scale illustration that assumes uniform distribution of hydrogen across stations; it does not model the detailed logistics of transporting hydrogen from a central plant to multiple retail stations. Future work should incorporate more detailed spatial and logistical modeling to assess the sensitivity of delivered cost to transport distance and station density.

Transportation and storage cost basis: The transportation (\$0.96-2.02/kg) and storage (\$0.21/kg) cost figures are adopted from Brattle Group (2024) [40]'s <150-mile compressed gaseous trucking scenario, with trailer capacities of approximately 560-900 kg H₂ and above-ground compressed-gas storage near 500 bar. However, several parameters that materially affect delivered cost - payload utilization, return-trip logistics, road-network fuel consumption, hydrogen losses in transit, and loading/unloading time - are not disclosed in the source report and are therefore inherited as embedded assumptions rather than independently modeled or verified in this study. This gap mirrors the cost-side limitation above: transportation and storage are treated as an aggregated external estimate rather than independently modeled, which also limits the extent to which the transportation-related cost and emissions accounting in this study can be fully harmonized.

Cost-emissions harmonization gap: The economic delivered-cost analysis in this study incorporates transportation and storage costs [40] alongside production-stage cost, whereas the environmental analysis (Section 3.4 and 4) is limited to well-to-gate production emissions and does not include transportation, storage, compression, or dispensing emissions. As a result, the cost and emissions accounting in this study are harmonized on the production stage only, not across the full delivered supply chain. Given that transportation has been shown to account for the majority of life-cycle global warming potential in comparable full-chain assessments [12], this omission means the emissions advantage attributed to the case study's nuclear-HTSE pathway should be understood as a production-stage result, not a delivered, full-chain comparison. Closing this gap would require applying a transportation-stage emissions model (e.g., extending the GREET framework with transport-specific inputs) consistent with the cost-side transportation assumptions identified above - a natural extension for future work building on this study's harmonized cost/emissions framework.

6. Recommendations

The findings above, together with the broader literature reviewed in Section 2, indicate five areas where further work and policy attention would do the most to advance nuclear-produced hydrogen as a viable fuel for the transportation sector. Because the case study covers a single reactor-electrolyser configuration and a single passenger vehicle, the recommendations below distinguish between what the case study itself supports and what is drawn more broadly from the literature synthesized in Section 2.

Within the economic analysis presented here, the largest cost escalation occurs after the plant gate rather than during hydrogen production. Nuclear-HTSE reaches a harmonized production cost of \$2.40/kg (June 2026 USD), yet station-level dispensing alone, calculated for this study using Argonne's HRSAM model, can add \$10.19-17.59/kg depending on station configuration and component-cost maturity, and the full delivered price climbs well beyond the plant-gate figure. Closing this gap will require redirecting research and policy attention away from production-side incentives alone and toward dispensing infrastructure specifically; high-pressure compression and improved cooling are the pieces most responsible for the cost escalation between plant gate and pump, and both warrant sustained investment.

Logistics also warrant attention. The literature reviewed in Section 2.3 indicates that transportation and distribution can account for most life-cycle global warming potential in full-chain hydrogen supply-chain assessments [12]. The case study's GREET-based emissions calculation covers hydrogen production-stage emissions and does not quantify downstream transportation, storage, compression, and dispensing. Accordingly, this case study cannot establish whether the production-stage emissions advantage of nuclear-produced hydrogen relative to a BEV supplied by the U.S. average electricity mix would persist after considering the full hydrogen supply chain. Future assessments should therefore explicitly incorporate these downstream stages. Small modular reactors and co-located hydrogen production centers merit further investigation in this context [47], since shorter transport distances could reduce downstream emissions and help preserve the low-carbon characteristics of nuclear-sourced hydrogen.

On the production side, the pathways with the best efficiency numbers are also the least mature. HTSE and the sulfur-iodine cycle reach system efficiencies as high as 90.2%, but durability issues, electrode instability, nickel oxidation, and damage from thermal cycling remain unresolved and continue to limit their readiness [24,25]. Materials research aimed at these failure modes should continue, alongside parallel work on the copper-chlorine cycle, which operates at a considerably lower peak temperature (500–550 °C versus the 900 °C the S-I cycle requires) and may therefore offer a more achievable near-term integration path [27].

The case study modeled a single passenger vehicle, the Toyota Mirai; it does not, by itself, provide evidence about how nuclear-coupled hydrogen economics would apply to other vehicle segments. Separately, the broader literature on FCV deployment trends suggests hydrogen's refueling speed and energy density may offer the greatest advantage in vehicle segments that are harder to electrify directly, such as heavy-duty trucking and long-haul fleets [6]. Whether the cost and emissions findings from this passenger-vehicle case study would hold, improve, or worsen for those segments, which involve different duty cycles, refueling volumes, and station economics, is a question this study was not designed to answer, and is identified here as a priority for future study rather than as a deployment recommendation this work can support directly.

Finally, the disconnect between production research and vehicle-level research should be addressed. Production studies routinely stop at the plant gate, while vehicle studies rarely account for the specific economics of nuclear-coupled production (Section 2.4). Future work should extend the integrated approach illustrated here, tracing hydrogen from a defined reactor design, through a defined transport distance, to a defined vehicle outcome, across additional reactor types, vehicle segments, and, where possible, primary (rather than secondary-review) cost data, since that is the level of detail policymakers would need to judge how nuclear-coupled hydrogen compares to other low-carbon options at scale.

7. Conclusions

This paper presented an integrated techno-economic and environmental case study of nuclear-produced hydrogen for fuel cell vehicles, informed by a synthesis of the existing literature joining production-side and vehicle-level outcomes for one reactor-electrolyzer configuration, a joint cost-and-emissions treatment that, as discussed in Section 2.4, existing full-chain studies approach from only one side at a time [11,12]. Within the scope of this single configuration, the results indicate that nuclear energy can supply an efficient, low-carbon feedstock for hydrogen production, though the broader viability of fuel cell vehicles depends heavily on what happens after the plant gate.

At the plant gate, the case study's nuclear-coupled high-temperature steam electrolysis configuration is cost-competitive: a harmonized production cost of \$2.40/kg (June 2026 USD) falls within reach of mid-term international targets for this specific GW-scale, n-th-of-a-kind (NOAK) configuration. That figure changes considerably once hydrogen reaches the pump. In the 40% utilization base case, delivered cost rises to \$13.76–22.22/kg once transportation, storage, and station dispensing are incorporated, an increase driven largely by station-level dispensing, calculated for this study using Argonne's HRSAM model, which spans \$10.19–17.59/kg depending on station configuration and component-cost maturity. Within this modeled configuration, a 600 kg/day station operating at 40% utilization, with tube-trailer transport and the specific technical and financial assumptions detailed in Section 3.3, the primary cost constraint lies in delivery rather than production. Because delivered cost is highly sensitive to station scale, utilization, and transport configuration, this finding should not be generalized beyond the specific case

examined here without further assessment of alternative delivery configurations. Nonetheless, this delivered-cost estimate remains substantially below the most recent verifiable California retail hydrogen pricing (\$34-36/kg, October 2024) [45], though no more recent retail assessment could be identified for this comparison, and the light-duty retail segment has contracted considerably since that figure was recorded.

The environmental case follows a broadly similar pattern within the case study's scope. Well-to-gate production emissions for the case study's HTSE configuration, evaluated using Argonne's 45VH2-GREET 2023 calculator, translate to production-stage emissions of approximately 1.4 g CO₂-eq per vehicle-mile, among the lower figures reported for hydrogen production pathways at this boundary. Whether this advantage persists once full hydrogen supply-chain logistics are counted is a question the case study does not resolve, since it excludes transportation, storage, compression, and dispensing emissions from the production-stage result. The broader literature indicates that transportation can account for a substantial share of full-chain life-cycle emissions in comparable systems [12]. For comparison, using GREET 2023 fuel-cycle electricity emission factors, the representative BEV produces approximately 105.5 g CO₂-eq/mile on the U.S. average electricity mix and 0.66 g CO₂-eq/mile under the LWR nuclear-electricity scenario. These values demonstrate the strong influence of electricity supply on BEV emissions; however, because the FCV figure reflects production-stage hydrogen emissions while the BEV figures reflect fuel-cycle electricity emissions, they should not be interpreted as a fully harmonized, well-to-wheel vehicle-level life-cycle comparison.

These findings indicate a need for research extending beyond reactor-level analysis to the infrastructure connecting it to the vehicle. Distributed production, including potential deployment of small modular reactors closer to hydrogen demand, could reduce the transport and logistics burden, although the case study did not evaluate that configuration directly. Progress on dispensing technology, particularly high-pressure compression and cooling, is needed to reduce the dispensing cost that dominates delivered cost in this case study. Separately, the broader literature on FCV deployment trends suggests heavy-duty and long-haul trucking may represent the greatest advantage of hydrogen over battery electrification [6]; this study's single passenger-vehicle case study does not test that claim, and it is flagged here as a direction for future research rather than a deployment recommendation this work can support directly.

Within the single reactor-electrolyser configuration and passenger vehicle examined here, the results indicate that nuclear-coupled HTSE can achieve a competitive plant-gate production cost and low production-stage emissions for this specific, favorable configuration (Section 5.4). These results should be understood as scenario-specific findings for one GW-scale NOAK design, one delivery configuration, and one vehicle segment, rather than as evidence that nuclear-produced hydrogen broadly meets cost or emissions targets across reactor types, delivery pathways, or vehicle applications. Full-chain emissions, alternative delivery configurations, and policy eligibility were not evaluated in this study and remain open questions. Future studies should extend the present case-study framework to multiple reactor configurations, hydrogen delivery pathways, and vehicle segments, incorporating full-chain emissions accounting, using consistent economic and environmental system boundaries.

Conflict of Interest: The authors declare no conflict of interest.

Data Availability Statement: No new publicly archived datasets were generated in this study. The model inputs, assumptions, CPI calculations, and outputs supporting the HRSAM and GREET results reported in this article are available from the corresponding author upon reasonable request.

Acknowledgments: During the preparation of this manuscript, the authors used ChatGPT (GPT-5.6 Luna), Claude (Claude Sonnet 5.5, Anthropic), Grammarly, and Consensus for the purposes of improving language and readability, assisting with the literature search, and supporting calculations. The authors have reviewed and edited the output and take full responsibility for the content of this publication.

Funding: This research received no external funding.

Author Contributions: Conceptualization, M.K.; Methodology, M.K.; Software, M.K.; Validation, M.K.; Formal Analysis, M.K.; Investigation, A.R. and M.K.; Resources, A.R.; Data Curation, M.K. and A.R.; Writing - Original Draft Preparation, M.K. and A.R.; Writing - Review & Editing, M.K. and A.R.; Visualization, A.R. All authors have read and agreed to the published version of the manuscript.

References

- [1] International Energy Agency. (2022). Net Zero by 2050: A Roadmap for the Global Energy Sector. Paris: IEA. <https://www.iea.org/reports/net-zero-by-2050> (accessed September 28, 2026).
- [2] International Atomic Energy Agency. (2024). Assessing Technical and Economic Aspects of Nuclear Hydrogen Production for Near Term Deployment (IAEA TECDOC-2075). Vienna: IAEA. <https://doi.org/10.61092/iaea.8uf6-pfqz>
- [3] World Nuclear Association. ((2024, May 17). Hydrogen Production and Uses. <https://world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses> (accessed September 28, 2026).
- [4] International Atomic Energy Agency. (2020, September). More Than Just a Power Source. IAEA Bulletin, 61(3). <https://www.iaea.org/bulletin/more-than-just-a-power-source> (accessed September 28, 2026).
- [5] International Atomic Energy Agency. (n.d.). Nuclear Hydrogen Production. IAEA Topics. <https://www.iaea.org/topics/non-electric-applications/nuclear-hydrogen-production> (accessed September 28, 2026).
- [6] U.S. Department of Energy. (2024). Hydrogen Shot: Water Electrolysis Technology Assessment. Washington, DC: DOE. <https://www.energy.gov/sites/default/files/2024-12/hydrogen-shot-water-electrolysis-technology-assessment.pdf> (accessed September 28, 2026).
- [7] Wendt, D. S., Knighton, L. T., & Boardman, R. D. (2022). *High-Temperature Steam Electrolysis Process Performance and Cost Estimates* (INL/RPT-22-66117, Revision 0). Idaho National Laboratory. https://inldigitallibrary.inl.gov/content/uploads/50/2026/04/Sort_60759.pdf (accessed September 28, 2026).
- [8] Nemitallah, M., Alnazha, A. A., Ahmed, U., El-Adawy, M., & Habib, M. A. (2024). Review on technoeconomics of hydrogen production using current and emerging processes: Status and perspectives. *Results in Engineering*, 21, Article 101890. <https://doi.org/10.1016/j.rineng.2024.101890>
- [9] Halder, P., Babaie, M., Salek, F., Shah, K., Stevanovic, S., Bodisco, T., & Zare, A. (2024). Performance, emissions and economic analyses of hydrogen fuel cell vehicles. *Renewable and Sustainable Energy Reviews*, 199, Article 114543. <https://doi.org/10.1016/j.rser.2024.114543>
- [10] Mohideen, M. M., Subramanian, B., Sun, J., Ge, J., Guo, H., Radhamani, A. V., Ramakrishna, S., & Liu, Y. (2023). Techno-economic analysis of different shades of renewable and non-renewable energy-based hydrogen for fuel cell electric vehicles. *Renewable and Sustainable Energy Reviews*, 174, Article 113153. <https://doi.org/10.1016/j.rser.2023.113153>
- [11] Lyu, R., Wang, Z., & Zhang, Z. (2025). Life Cycle Assessment Based on Whole Industry Chain Assessment of FCEVs. *Sustainability*, 17(12), 5431. <https://doi.org/10.3390/su17125431>
- [12] Li, Z., Huang, S., Liu, X., & Wu, H. (2024). "Energy-environment" life cycle assessment and comparison of a nuclear-based hydrogen production system. *International Journal of Hydrogen Energy*. <https://doi.org/10.1016/j.ijhydene.2024.11.274>
- [13] Rocha, F., Georgiadis, C., Van Droogenbroek, K., Delmelle, R., Pinon, X., Pyka, G., Kerckhofs, G., Egert, F., Razmjooei, F., Ansar, S., Mitsushima, S., & Proost, J. (2024). Proton exchange membrane-like alkaline water electrolysis using flow-engineered three-dimensional electrodes. *Nature Communications*, 15, Article 7444. <https://doi.org/10.1038/s41467-024-51704-z>

- [14] Liu, L. H., Khan, M., & Hsiao, B. S. (2024). Recent Advances and Challenges in Anion Exchange Membranes Development/Application for Water Electrolysis: A Review. *Membranes*, 14(4), 85. <https://doi.org/10.3390/membranes14040085>
- [15] Zubair, M., & Sajna, M. S. (2026). Integration of electrolytic hydrogen production with the Barakah APR1400 nuclear power facility. *International Journal of Hydrogen Energy*, 254, 156323. <https://doi.org/10.1016/j.ijhydene.2026.156323>
- [16] Wang, T., Cao, X., & Jiao, L. (2022). PEM water electrolysis for hydrogen production: fundamentals, advances, and prospects. *Carbon Neutrality*, 1, Article 21. <https://doi.org/10.1007/s43979-022-00022-8>
- [17] Xi, B., Feng, T., & Zhang, T. (2025). Hydrogen Energy: Hydrogen Production through Water Electrolysis Technology. *Frontiers in Sustainable Development*, 5(2), 83-87. <https://doi.org/10.54691/sw3j3m37>
- [18] An, L., Wei, C., Lu, M., Liu, H., Chen, Y., Scherer, G., Fisher, A., Xi, P., Xu, Z. J., & Yan, C. (2021). Recent Development of Oxygen Evolution Electrocatalysts in Acidic Environment. *Advanced Materials*, 33(20), Article 2006328. <https://doi.org/10.1002/adma.202006328>
- [19] Wang, J., Yang, J., Feng, Y., Hua, J., Chen, Z., Liao, M., Zhang, J., & Qin, J. (2025). Comparative experimental study of alkaline and proton exchange membrane water electrolysis for green hydrogen production. *Applied Energy*, 379, Article 124936. <https://doi.org/10.1016/j.apenergy.2024.124936>
- [20] Azam, A. M. I. N., Li, N. K., Zulkefli, N. N., Masdar, M. S., Majlan, E., Baharuddin, N. A., Zainoodin, A. M., Yunus, R. M., Shamsul, N. S., Husaini, T., & Shaffee, S. N. A. (2023). Parametric Study and Electrocatalyst of Polymer Electrolyte Membrane (PEM) Electrolysis Performance. *Polymers*, 15(3), 560. <https://doi.org/10.3390/polym15030560>
- [21] Wang, X., Star, A., & Ahluwalia, R. (2023). Performance of Polymer Electrolyte Membrane Water Electrolysis Systems: Configuration, Stack Materials, Turndown and Efficiency. *Energies*, 16(13), 4964. <https://doi.org/10.3390/en16134964>
- [22] Alabbadi, A. A., & Alzahrani, A. A. (2024). Nuclear hydrogen production using PEM electrolysis integrated with APR1400 power plant. *International Journal of Hydrogen Energy*, 60, 241-260. <https://doi.org/10.1016/j.ijhydene.2024.02.133>
- [23] Chen, Z., Su, C., Zhan, H., Chen, L., Wang, W., Zhang, H., Chen, X., Sun, C., Kong, Y., Yang, L., Du, X., & Zhang, N. (2024). Thermodynamic and economic analyses of nuclear power plant integrating with seawater desalination and hydrogen production for peak shaving. *International Journal of Hydrogen Energy*, 82, 1372-1388. <https://doi.org/10.1016/j.ijhydene.2024.08.055>
- [24] Vostakola, F. M., Ozcan, H., El-Emam, R., & Horri, B. A. (2023). Recent Advances in High-Temperature Steam Electrolysis with Solid Oxide Electrolysers for Green Hydrogen Production. *Energies*, 16(8), 3327. <https://doi.org/10.3390/en16083327>
- [25] Yuan, J., Li, Z., Yuan, B., Xiao, G., Li, T., & Wang, J.-Q. (2023). Optimization of High-Temperature Electrolysis System for Hydrogen Production Considering High-Temperature Degradation. *Energies*, 16(6), 2616. <https://doi.org/10.3390/en16062616>
- [26] Safari, F., & Dincer, I. (2020). A review and comparative evaluation of thermochemical water splitting cycles for hydrogen production. *Energy Conversion and Management*, 205, Article 112182. <https://doi.org/10.1016/j.enconman.2019.112182>
- [27] Hercog, J., Kupecki, J., Świątkowski, B., Kowalik, P., Boettcher, A., Malesa, J., Skrzypek, E., Skrzypek, M., Muszyński, D., & Tchorek, G. (2023). Advancing production of hydrogen using nuclear cycles - integration of high temperature gas-cooled reactors with thermochemical water splitting cycles. *International Journal of Hydrogen Energy*, 52, 1070-1083. <https://doi.org/10.1016/j.ijhydene.2023.06.333>

- [28] Zhang, J., He, Y., Zeng, J., Song, W., Weng, W., & Wang, Z. (2025). Updating and 24 H Testing of State Key Laboratory of Clean Energy Utilization's Thermochemical Iodine-Sulfur Cycle Water-Splitting Hydrogen Production System. *Applied Sciences*, 15(9), 5183. <https://doi.org/10.3390/app15095183>
- [29] Ni, H., Qu, X., Zhao, G., Zhang, P., & Peng, W. (2024). Research on two novel hydrogen-electricity-heat polygeneration systems using very-high-temperature gas-cooled reactor and hybrid-sulfur cycle. *Energy*, 290, Article 130187. <https://doi.org/10.1016/j.energy.2023.130187>
- [30] Ghorbani, B., Zendejboudi, S., Zhang, Y., Zarrin, H., & Chatzis, I. (2023). Thermochemical watersplitting structures for hydrogen production: Thermodynamic, economic, and environmental impacts. *Energy Conversion and Management*, 297, Article 117599. <https://doi.org/10.1016/j.enconman.2023.117599>
- [31] Corgnale, C., Gorenssek, M., & Summers, W. (2020). Review of Sulfuric Acid Decomposition Processes for Sulfur-Based Thermochemical Hydrogen Production Cycles. *Processes*, 8(11), 1383. <https://doi.org/10.3390/pr8111383>
- [32] Delgado, H. E., Cappello, V., Zang, G., Sun, P., Ng, C., Vyawahare, P., Elgowainy, A., Wendt, D., Boardman, R., & Marcinkoski, J. (2023). Techno-economic analysis and life cycle analysis of e-fuel production using nuclear energy. *Journal of CO2 Utilization*, 72, Article 102481. <https://doi.org/10.1016/j.jcou.2023.102481>
- [33] Mendrela, P., Stanek, W., & Simla, T. (2023). Sustainability assessment of hydrogen production based on nuclear energy. *International Journal of Hydrogen Energy*, 49, 729-744. <https://doi.org/10.1016/j.ijhydene.2023.07.156>
- [34] Aydin, M., & Dincer, I. (2022). An assessment study on various clean hydrogen production methods. *Energy*, 245, Article 123090. <https://doi.org/10.1016/j.energy.2021.123090>
- [35] Karaca, A., Dincer, I., & Gu, J. (2020). Life cycle assessment study on nuclear based sustainable hydrogen production options. *International Journal of Hydrogen Energy*, 45, 22148-22159. <https://doi.org/10.1016/j.ijhydene.2020.06.030>
- [36] Ji, M., Shi, M., & Wang, J. (2023). Life cycle assessment of nuclear hydrogen production processes based on high temperature gas-cooled reactor. *International Journal of Hydrogen Energy*, 48, 22302-22318. <https://doi.org/10.1016/j.ijhydene.2023.03.140>
- [37] Halder, P., Babaie, M., Salek, F., Haque, N., Savage, R., Stevanovic, S., Bodisco, T., & Zare, A. (2023). Advancements in hydrogen production, storage, distribution and refuelling for a sustainable transport sector: Hydrogen fuel cell vehicles. *International Journal of Hydrogen Energy*, 52, 973-1004. <https://doi.org/10.1016/j.ijhydene.2023.07.204>
- [38] Reddi, K., Elgowainy, A., Rustagi, N., & Gupta, E. (2017). Impact of Hydrogen Refueling Configurations and Market Parameters on the Refueling Cost of Hydrogen. *International Journal of Hydrogen Energy*, 42(36), 21855-21865. <https://doi.org/10.1016/j.ijhydene.2017.05.122>
- [39] U.S. Bureau of Labor Statistics. (n.d.). *Consumer Price Index for All Urban Consumers (CPI-U): All Items in U.S. City Average, Not Seasonally Adjusted* (Series CUUR0000SA0). U.S. Department of Labor. <https://data.bls.gov/timeseries/CUUR0000SA0> (accessed September 28, 2026).
- [40] Graves, F., Figueroa, J., Sreenath, R., Sala, L., Grove, J., & Thumb, S. (2024). Emerging Economics of Hydrogen Production and Delivery. The Brattle Group, commissioned by Environmental Defense Fund. <https://www.brattle.com/wp-content/uploads/2024/02/Emerging-Economics-of-Hydrogen-Production-and-Delivery-2-2024.pdf> (accessed September 2, 2026)
- [41] Argonne National Laboratory. (n.d.). *Hydrogen Refueling Station Analysis Model (HRSAM), Version 2.0* [Computer software]. Hydrogen Delivery Infrastructure Analysis, U.S. Department of Energy. <https://hdsam.es.anl.gov/index.php?content=hrsam> (accessed September 28, 2026)

- [42] U.S. Department of Energy & U.S. Environmental Protection Agency. (2026). *2026 Toyota Mirai* [Fuel economy data]. FuelEconomy.gov. <https://www.fueleconomy.gov/feg/Find.do?action=sbs&id=50311> (accessed September 28, 2026).
- [43] Argonne National Laboratory. (2023). *45VH2-GREET* (Rev. December 2023) [Computer software]. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. <https://www.energy.gov/eere/greet> (accessed September 28, 2026).
- [44] U.S. Department of Energy & U.S. Environmental Protection Agency. (2026). *2026 Tesla Model 3 Standard RWD* [Fuel economy data]. FuelEconomy.gov. <https://www.fueleconomy.gov/feg/noframes/50251.shtml> (accessed September 28, 2026).
- [45] Hydrogen Central. (2024, October 2). *California hydrogen pump prices for light-duty vehicles reach new highs*. <https://hydrogen-central.com/california-hydrogen-pump-prices-for-light-duty-vehicles-reach-new-highs/> (accessed September 28, 2026).
- [46] Letsios, K., Charisiou, N. D., Skodras, G. S., Goula, M. A., & Douvartzides, S. L. (2026). Hydrogen Compression Choices for Tomorrow's Refueling Stations: Review of Recent Advances and Selection Guide. *Hydrogen*, 7(1), 25. <https://doi.org/10.3390/hydrogen7010025>
- [47] Serin, C., Glückler, M., Pasquet, M., & Vaglio-Gaudard, C. (2025). Outcomes of three Euratom projects on cogeneration of electricity, heat and hydrogen. *EPJ Nuclear Sciences & Technologies*. <https://doi.org/10.1051/epjn/2025007>

Disclaimer: "The views, opinions, and data presented in this publication are exclusively those of the author(s) and contributor(s) and do not necessarily reflect those of JENMAS or its editor(s). JENMAS and the editor(s) accept no liability for any loss, damage, or injury to persons or property arising from the use of any ideas, methods, instructions, or products discussed herein."