March 25, 2025

California Air Resources Board
1001 Ninth Street
Sacramento, CA 95814

Re: SB 1075 Report Development – Comments on the CARB Workshop held February 25, 2025

On behalf of the California Hydrogen Coalition (CHC), we thank the California Air Resources Board (CARB) for its leadership in implementing Senate Bill 1075 (Skinner, 2022). We commend CARB for hosting the February 25, 2025, workshop and support the development of a robust report that characterizes hydrogen's role in decarbonizing California's energy, industrial, and transportation sectors. CHC strongly supports the SB 1075 effort and urges CARB to ensure that the final report reflects hydrogen's contributions to achieving the state's zero-emission vehicle (ZEV), carbon neutrality, and energy resilience goals.

GENERAL COMMENTS ON FRAMING AND SCOPE

CHC urges CARB and its consultants, including E3, to evaluate hydrogen in the context of the fossil fuels it displaces—primarily diesel, gasoline, and fossil-derived natural gas—rather than as a competitor to other decarbonization technologies. The framing should reflect the intent of SB 1075 to evaluate hydrogen as a clean energy vector and emissions reduction tool, not to rank or discredit solutions through comparative analysis that overlooks differences in application and suitability.

On Slide 28 of E3's presentation, the "Clean Alternatives Analysis" could be misinterpreted as positioning hydrogen in competition with battery electric or grid-based solutions, rather than highlighting its complementarity. Hydrogen is uniquely capable of decarbonizing sectors that are hard to electrify directly—such as long-haul heavy-duty transport, high-temperature industrial processes, seasonal power storage, and remote off-grid applications. Therefore, it is essential that hydrogen be evaluated against incumbent fossil fuel systems based on well-to-gate lifecycle emissions, not against technologies with different use cases.

A robust **technoeconomic analysis (TEA)** is essential to evaluating hydrogen's role in decarbonization. Rather than a purely financial or emissions-focused model, a comprehensive TEA integrates technical feasibility, lifecycle costs, and system-wide benefits to provide a full picture of hydrogen's viability as an energy source compared to fossil incumbents.

To be meaningful, a TEA must begin with a detailed process design and system configuration, capturing the specific hydrogen production technology (e.g., steam methane reforming, electrolysis, autothermal reforming, methane pyrolysis), its operational conditions (temperature, pressure, energy inputs), and scale. Each production pathway has unique capital and operational requirements that directly influence cost and performance outcomes. This analysis should contextualize regional market fundamentals, including the ability for different production technologies to integrate with the existing energy systems.

The first key component is **capital expenditure (CAPEX)**, which accounts for equipment, installation, and integration. For hydrogen systems, this includes production technologies such as reformers, pyrolysis or electrolyzers; gas handling systems including compression , gas purification, liquefaction, product

storage; midstream assets such as pipelines storage and tanker trucks and end use delivery systems such as fueling stations. A meaningful TEA should specify whether costs are front-loaded (e.g., centralized production) or distributed (e.g., onsite generation), and how those costs change with economies of scale.

Operating expenditures (OPEX) are equally critical. These include recurring costs such as feedstocks (electricity, natural gas, water, or biomass), maintenance, labor, and utility services (cooling, water purification, waste disposal). Because hydrogen production often consumes large volumes of electricity or thermal energy, accurate modeling of feedstock price volatility and availability is essential.

Closely linked to operating cost is energy efficiency, typically measured as the ratio of energy output (in hydrogen) to input (in electricity or chemical energy), expressed using the higher heating value (HHV) or lower heating value (LHV). Each pathway has its own efficiency range:

- **Electrolysis**: 60–80% (HHV), depending on electrolyzer type and operating conditions.
- **Steam methane reforming (SMR)**: 65–75%, declining slightly when carbon capture is included.
- **Autothermal reforming (ATR)**: 55–70%, often optimized for integration with CCS.
- **Methane pyrolysis**: Up to 85%, due to the absence of CO_2 formation and lower water requirements.

Another crucial metric is water consumption, which varies widely by production method. Electrolysis uses water directly as a feedstock and requires between 9–18 liters of purified water per kilogram of hydrogen produced, with higher values including cooling needs. SMR and ATR use water as steam, consuming about 6–9 liters/kg. Methane pyrolysis has minimal water use, limited mainly to cooling loops. For comparison, refining gasoline and diesel typically uses 9–11 liters per gasoline gallon equivalent (gge). Importantly, hydrogen production—even using electrolysis at large scale—consumes a tiny fraction of California's water budget: less than 0.5% of the agricultural sector's 11 trillion gallon annual usage.

The TEA must also quantify well-to-gate lifecycle greenhouse gas (GHG) emissions, expressed as carbon intensity (CI) in grams of CO_2-equivalent per megajoule (gCO_2e/MJ). This enables technology-neutral comparison across feedstocks and production pathways. For example, biomethane-based SMR or gasification of agricultural residues can produce hydrogen with near-zero or even **negative CI**, depending on methane capture and biochar sequestration. Electrolytic hydrogen using 100% renewable electricity also has near-zero CI, while grid-powered electrolysis varies by the carbon intensity of the local electricity mix.

Finally, a TEA must calculate hydrogen production costs on a per-kilogram basis across scenarios, clearly specifying the assumption on asset utilization, as it can significantly impact the level cost of production:

- **Electrolysis** ranges from $2.50 to $6.80/kg depending primarily on electricity cost and capacity factor.
- **SMR** is typically $1.00–$3.00/kg, depending on natural gas price and whether CCS is deployed.
- **ATR and pyrolysis** fall between $1.50–$3.50/kg, with potential for negative emissions credits in pyrolysis.

These costs are competitive with gasoline and diesel on an energy-equivalent basis—especially when externalities (air pollution, climate impacts) are accounted for. More importantly, many hydrogen pathways offer additional benefits not captured by simple cost comparisons: air quality improvement, reduced reliance on critical minerals, grid stability through dispatchable power, and rural job creation via biomass and biogas sourcing.

A full TEA should also include sensitivity analysis, testing how variations in electricity or feedstock price, capital costs, or regulatory policies (e.g., LCFS or 45V tax credit levels) affect outcomes. This helps identify policy levers and de-risk investment pathways.

In summary, CHC recommends that CARB adopt a TEA framework that prioritizes:

1. **Decarbonization potential** through lifecycle CI evaluation.
2. **Energy security and reliability**, with multiple domestic feedstock options.
3. **Economic performance and job creation**, especially in underserved communities.
4. **Reduced reliance on mined or extracted critical resources**, especially relevant for comparison to lithium-ion battery systems.

Only through this comprehensive, system-aware, and policy-informed technoeconomic framework can the SB 1075 report accurately reflect hydrogen's role in California's energy transformation.

Disparities in Policy Support for Hydrogen

Despite growing expectations for hydrogen to play a foundational role in decarbonizing transportation and the broader energy system, public investment in hydrogen infrastructure has been strikingly limited when compared to the support extended to electric vehicles and charging systems.

According to a 2022 analysis of EV infrastructure programs by the California Hydrogen Coalition (CHC), over $7.38 billion has been appropriated across state and regulatory programs for zero-emission vehicle (ZEV) infrastructure. Of this, just 3.55%—approximately $262 million—was allocated to hydrogen infrastructure, while more than 96% supported battery electric vehicle (BEV) charging and related systems. This figure excludes additional local and federal investments, school bus charging programs, and public utility expenditures that overwhelmingly favor BEV deployment.

Yet the performance of hydrogen fueling infrastructure on a public investment basis has been demonstrably strong. As detailed in the Clean Transportation Program Hydrogen Evaluation (CTP H2), hydrogen infrastructure has delivered nearly three times more energy throughput per public dollar invested compared to publicly funded DC fast charging. This includes the higher utilization of retail hydrogen stations, the ability to support medium- and heavy-duty applications, and the consistent delivery of high energy flows at scale—attributes critical to equity and energy resilience across rural, high-mileage, and underserved regions.

This funding gap is particularly incongruent given the mandates for FCEV deployment under the Advanced Clean Trucks (ACT), Advanced Clean Fleets (ACF), and Innovative Clean Transit (ICT) regulations, as well as CARB's own projections for tens of thousands of fuel cell electric trucks, buses, and light-duty vehicles in the 2035–2045 timeframe.

In contrast, the electric sector's transition to renewables and electrification has been extensively supported by structured procurement mandates and cost recovery mechanisms. The CPUC's annual Padilla Report on the RPS Program shows that California electricity ratepayers have supported over $5 billion annually in renewable electricity procurement, often with structured financial obligations extending across 10–20 years to guarantee investment return and developer confidence.

Hydrogen has received no such equivalent guarantee, nor a sustained public funding strategy.

To achieve the equitable and scalable deployment of decarbonized hydrogen envisioned in SB 1075, CARB and the state must provide policy certainty and parity for hydrogen infrastructure development. This includes:

- A statewide network of LD/MD stations[1] and HD stations[2] to fully support California's Zero-Emission Vehicle goal[3][4]
- Dedicated multi-year funding and cost-recovery mechanisms for production, storage, and fueling.
- Grid access that accounts for the specific requirements of 45V, costs, curtailment, and demand response.
- Equity-focused investments that extend hydrogen access to disadvantaged communities and commercial fleets.
- Performance-based investment structures that reward throughput and public value, not just installed capacity.

Without clear and consistent support, the state risks undercutting one of its most effective tools for reducing emissions in hard-to-electrify sectors and achieving deep decarbonization. The policy expectations for hydrogen are high; the support must be commensurate.

Water Consumption Context and the Case for Policy-Standard Metrics

When evaluating hydrogen production, it is critical to assess water consumption not in isolation, but in the context of existing energy production systems. Moreover, to effectively integrate hydrogen into California's energy and environmental planning, water use should be expressed in terms that align with state and regional water resource management frameworks — most notably, acre-feet.

An acre-foot is the volume of water needed to cover one acre of land to a depth of one foot, equivalent to 325,851 gallons or 1,233,000 liters. It is the standard unit used by California water agencies for policy planning and allocations.

Water Consumption by Fuel Type (Liters/MJ and Gallons/gge)

Fuel / Energy Source	Water Use (liters/MJ)	Water Use (L/kg H_2 or per gge)	Approx. Acre-Feet per 1 Billion MJ*
Electrolysis (H_2)	~0.075 L/MJ	~9–18 L/kg H_2	~60,800–121,500
SMR / ATR (H_2)	~0.054–0.060 L/MJ	~6–9 L/kg H_2	~43,800–70,000
Methane Pyrolysis (H_2)	~0.01–0.02 L/MJ (cooling only)	~1–2 L/kg H_2	~8,000–16,000
Gasoline (refining)	~0.088 L/MJ	~10.6 L/gge	~70,800
Diesel (refining)	~0.079 L/MJ	~9.5 L/gge	~63,500
Natural Gas (processing)	~0.06 L/MJ	~7.2 L/gge	~48,400
Electricity (CCNG w/ cooling)	~0.10–0.63 L/MJ	~0.378–2.27 L/kWh	~90,000–570,000

*Assumes 1 billion MJ of delivered energy for consistent scale.

[1] Hydrogen Fuel Cell Partnership – California Fuel Cell Revolution
[2] Senate Bill 671 Report: Clean Freight Corridor Efficiency Assessment
[3] Executive Order N-79-20
[4] Executive Order B-48-18

Observations

- Electrolysis, particularly with renewable power, is sometimes criticized for water use. However, even at the high end (~18 L/kg), the total water demand remains modest when translated to policy scales. Producing 100,000 metric tons of hydrogen via electrolysis (~3.3 million MWh of energy) would require about 1,800 acre-feet of water — roughly 0.016% of the water used annually for California agriculture (~11 million acre-feet).
- Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) consume slightly less water than electrolysis but still provide substantial carbon benefits when paired with renewable feedstocks or carbon capture.
- Gasoline and diesel refining use a similar amount of water on an energy-equivalent basis. Replacing them with hydrogen does not increase water demand, and in many cases reduces it, particularly when low-water-intensity production like methane pyrolysis is deployed and the improved fuel economy of H2 fuel cell transportation as compared to gasoline or diesel is taken into account.
- Combined cycle natural gas plants with cooling towers are among the most water-intensive per MWh. At the upper end (2.27 L/kWh), they can use over 550,000 acre-feet per year for a mid-sized 1 GW plant — far exceeding any hydrogen production facility's footprint.

Recommendations

1. Use Acre-Feet in TEA and Policy Frameworks: CARB should require water consumption reporting in acre-feet per year and acre-feet per PJ (petajoule) or TWh, enabling integration with Department of Water Resources (DWR) and State Water Board planning models.
2. Evaluate Water Intensity by Energy Delivered: Just as CARB assesses carbon intensity in grams CO_2e/MJ, water use should be assessed per unit of energy or per mile traveled, not per molecule of hydrogen produced.
3. Prioritize Low-Carbon, Low-Water Pathways: Pathways like methane pyrolysis (especially with renewable biogas) and high-efficiency electrolysis using behind-the-meter solar can minimize both carbon and water intensity.
4. Account for Co-Benefits: Hydrogen production can upcycle waste water or agricultural runoff, and when sourced from biomass/biogas, it can also divert methane, yielding net environmental benefits far beyond water use alone.

Hydrogen's water consumption is comparable — and in some cases lower — than incumbent fuels. When expressed in acre-feet, it becomes clear that hydrogen can scale without creating new burdens on California's water supply, particularly when production is optimized for location, feedstock, and co-product recovery. Water policy and decarbonization policy should be aligned, and hydrogen is one of the few technologies that enables both.

RESPONSE TO CARB WORKSHOP QUESTIONS (SLIDE 32)

Question 1: Confidential Information Submission CHC recommends CARB provide a secure portal or formal procedure—modeled on the LCFS Tier 2 confidential data pathway—to allow companies to submit business-sensitive TEA data or proprietary technology information. Transparency in modeling is important, but must be balanced with protecting intellectual property essential to project finance and innovation.

Question 2: Recent Developments in Hydrogen Technology Toyota's recent announcement of a next-generation fuel cell system with a 20% boost in efficiency and significantly longer stack life highlights the accelerating pace of innovation. However, decarbonization—not device efficiency—must remain the primary evaluation metric. Multiple academic and industry analyses (LLNL, IPHE, Plug Power, ACORE) confirm that lifecycle emissions, not point efficiency, determine environmental value. Additionally, hydrogen's minimal dependence on rare earth minerals and critical battery inputs supports U.S. energy independence and mitigates global resource and trade risk.

Question 3: Modeling Infrastructure Hydrogen should be modeled as a system that mimics the proven liquid fuel supply chain:

- **Regional production** (electrolysis, reforming, pyrolysis, gasification) aligned with feedstock availability (renewable power, biogas, waste biomass).
- **Transmission infrastructure**, including dedicated pipelines, liquid hydrogen transport trailers and tube trailers.
- **Distribution terminals and liquefaction centers**, acting as strategic hydrogen "racks" similar to existing fuel terminals.
- **Refueling infrastructure** built near demand centers for transportation.

Question 4: Recommended Reports and Studies

- **LLNL's Getting to Neutral (2020):** Found that biomass gasification and biogenic hydrogen with CCS are the most cost-effective negative emission solutions in California (costs as low as $60/ton CO2e).
- **ARCHES Sector Roadmaps (2023):** Detailed how hydrogen integrates into hard-to-electrify sectors across power, transport, and industrial use cases.
- **IPHE LCA Guidance (2022):** Provides harmonized international best practices for CI accounting across hydrogen pathways.
- **REPowerEU and Hydrogen Backbone (EU 2022):** Demonstrates strong EU commitment to H2 pipeline corridors, terminal infrastructure, and large-scale production zones.
- **DOE Hydrogen Strategy and Roadmap (2023):** U.S. national planning document outlining clean hydrogen hubs, cost targets ($1/kg H2), and deployment timelines.
- **CARB Hydrogen Self-Sufficiency Report (2021):** Concluded that ~$300M would enable a commercially sustainable light-duty refueling market in California.
- **Harnessing Hydrogen – A Key Element of the U.S. Energy Future:** This is a comprehensive study on the deployment of LCI hydrogen at-scale in the U.S. to support decarbonization of various energy and industrial market sectors across the entire value chain, including production, storage, transportation, and end uses. Over 100 organizations contributed to the study, including a number of CHC members.
- **Study on impact of deployment of battery electric vehicles (BEV) and fuel cells electric vehicles (FCEV) infrastructure:** funded by the European Commission and completed by McKinsey, indicates that "[t]wo infrastructures are better than one. A future optimal mix of infrastructure would include both BEV and FCEV infrastructures… Our analysis found that a 100% BEV ecosystem could cost €3 trillion to €5 trillion more through 2050 from an infrastructure perspective than a combined ecosystem."
- **Hydrogen Fuel Cell Partnership Resources:** https://h2fcp.org/resources

RESPONSE TO SAFETY CONCERNS (E3 SLIDE 36)

Hydrogen is governed by a mature and internationally accepted set of codes and standards. These include:

- **NFPA 2 – Hydrogen Technologies Code:** Covers requirements for hydrogen generation, storage, use, and refueling infrastructure. It includes zoning setbacks, leak detection, ventilation, fire suppression, and emergency response protocols.
- **ISO 19880-1:** Specifies minimum safety performance requirements for hydrogen refueling stations, including pressure containment, fueling protocols, material compatibility, and failure testing.
- **SAE J2601:** Defines safe and standardized fueling protocols (flow rate, pressure ramp, and thermal management) for hydrogen vehicle tanks.
- **ASME Boiler and Pressure Vessel Code Section VIII & API 5L/6A:** These cover mechanical design, inspection, and integrity requirements for pressure vessels, hydrogen pipelines, and high-pressure storage. These standards are used in the U.S., EU, Japan, and Korea, and ensure safe deployment of hydrogen infrastructure. In California, hydrogen refueling stations have operated for over a decade with no major safety incidents.

CONCLUSION

CHC supports the SB 1075 process and believes CARB has a critical opportunity to define hydrogen's role in a balanced, inclusive, and science-based manner. We urge CARB to:

- Frame hydrogen as a replacement for fossil fuels, not a competitor to electrification.
- Incorporate a full technoeconomic analysis using lifecycle CI and cost-effective metrics.
- Align the report with international LCA standards and infrastructure modeling.
- Leverage existing safety codes to address deployment concerns.

Hydrogen’s value is not limited to one use case or sector. It is a uniquely flexible tool for decarbonization, resilience, and equity. With multiple production pathways, cross-sector applications, and integration potential, hydrogen can support California’s energy transition and climate leadership across the board.

Sincerely,

/s/

Teresa Cooke
Executive Director
California Hydrogen Coalition