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California Hydrogen Coalition's Comments

Additional submitted attachment is included below.

March 20, 2026

Chair David Hochschild
California Energy Commission
Docket Unit, MS-4
715 P Street
Sacramento, CA 95814-5512

Re: Docket No. 23-SB-100 – California Hydrogen Coalition Comments on the February 19, 2026, Workshop on 2025 SB 100 Draft Results

Dear Chair Hochschild and Members of the Commission:

I. Introduction

The California Hydrogen Coalition (CHC) submits these comments on the draft modeling results and inputs and assumptions presented at the February 19, 2026 workshop for the 2025 SB 100 Report.[1] CHC appreciates the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Air Resources Board (CARB) (collectively, the Joint Agencies) for extending the public comment period to allow substantive stakeholder engagement.

CHC represents the full hydrogen value chain in California, including producers of renewable and low-carbon hydrogen across multiple feedstock pathways, midstream companies providing trucked and pipeline distribution and storage, fueling station developers and operators, and original equipment manufacturers of fuel cell electric vehicles for light-, medium-, and heavy-duty applications. CHC members are also active in stationary fuel cell deployment, distributed energy resources, and clean firm power generation, with direct involvement in major utility hydrogen programs in the Los Angeles Basin.

CHC shares the Joint Agencies' commitment to achieving the SB 100 mandate for 100 percent clean electricity by 2045 and the economy-wide carbon neutrality goal established by AB 1279.[2] These comments advance a single central concern: the draft modeling results structurally undervalue hydrogen across several planning dimensions. The compounding affect of the h2 assumptions produce a picture of hydrogen's role that is substantially narrower than California's adopted policy trajectory and utility planning studies, such as the LA100 study.

The draft results themselves provide the strongest evidence for this concern. The Combustion Retirement scenario, the most aggressive decarbonization scenario modeled, selects five gigawatts of hydrogen fuel cells as the resource that makes full fossil gas retirement achievable. This is the model's

[1] California Energy Commission, California Public Utilities Commission, & California Air Resources Board. (2026, February 19). 2025 Senate Bill (SB) 100: Draft Results Workshop [Presentation]. Docket No. 23-SB-100. https://efiling.energy.ca.gov/GetDocument.aspx?tn=268689&DocumentContentId=105843

[2] SB 100 (De Leon, Chapter 312, Statutes of 2018); AB 1279 (C. Garcia, Chapter 337, Statutes of 2022).

own cost optimization logic concluding that there is no pathway to full combustion retirement without hydrogen-based firm generation. CHC's comments explain why this finding should inform the report's overall framing, and why the modeling choices that prevent hydrogen from appearing in less-constrained scenarios should be acknowledged as limitations, rather than presented as market findings.

These comments address five issues: the structural modeling limitations that understate hydrogen's role (Section II); hydrogen combustion turbines as expansion candidates (Section III); transportation hydrogen demand scenarios (Section IV); hydrogen delivery infrastructure (Section V); and non-energy benefits (Section VI). Section VII sets forth CHC's recommendations for addressing these concerns in the forthcoming draft SB 100 report.

II. Structural Modeling Choices Systematically Understate Hydrogen's Role

When the model runs a scenario retiring all thirty-five gigawatts of in-state fossil gas, it selects 5 gigawatts of hydrogen fuel cells as the technology that closes the reliability gap. This directly validates what LADWP's LA100 Study and 2022 LA100 Plan independently established: there is no modeled pathway to full combustion retirement without hydrogen-based firm generation.[3,] Yet across every other scenario, hydrogen generation plays a minimal role. In the Comparison scenario, the model's cleanest economic signal, hydrogen generation is not selected at all. Hydrogen appears in the Reference scenario only because it is inherited from LSE-planned resources, not because the model chose it. The Higher Hydrogen Demand scenario produces a system impact the Joint Agencies characterize as approximately 1 gigawatt, negligible relative to the 27-to-87-gigawatt range of retail demand variation across scenarios.

This pattern reflects four structural modeling choices that compound to prevent hydrogen from being fairly evaluated. First, hydrogen combustion turbines face fixed capital cost adders from SB 423 that prevent economic competition regardless of fuel cost, while no scenario is designed to isolate or value the reliability services hydrogen resources (particularly flexible demand) can uniquely provide. Second, electrolytic hydrogen loads are modeled as a fixed demand shape rather than as a dispatchable grid resource whose flexibility has system value. Third, transportation hydrogen demand is calibrated below the state's own Scoping Plan targets. Fourth, Hydrogen delivery is represented by a generic fixed-cost adder that cannot reflect the economies of scale of pipeline infrastructure.

CHC also notes that the 2021 SB 100 Report explicitly recommended that the 2025 report continue to evaluate the potential effects of clean and renewable hydrogen technologies and demand flexibility.[4] The modeling advances made for offshore wind, including a dedicated 25 gigawatt scenario, were not matched by comparable advances in hydrogen scenario design. The final report should acknowledge this gap and commit to specific methodological improvements for the 2029 modeling cycle.

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[3] Los Angeles Department of Water and Power. (2021). LA100: The Los Angeles 100% Renewable Energy Study. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy21osti/79444-10.pdf; see also, Los Angeles Department of Water and Power. (2022). 2022 Strategic Long-Term Resource Plan. LADWP.

[4] California Energy Commission. (2024, April 16). 2025 Senate Bill (SB) 100: Non-Energy Impacts Workshop [Presentation]. Docket No. 23-SB-100, TN 255711. https://efiling.energy.ca.gov/GetDocument.aspx?tn=255711&DocumentContentId=91538.

III. Hydrogen Combustion Turbines Must Be Meaningfully Evaluated as Expansion Candidates

Hydrogen combustion turbines are listed as available expansion candidates in Inputs and Assumptions, yet they are not economically selected in any scenario.[5] The workshop presentation characterizes this as evidence that hydrogen resources are not cost competitive as modeled. CHC respectfully submits that this characterization conflates a modeling result with a market conclusion, and the final report should be precise about the distinction.

Three factors explain the non-selection, none of which reflect the underlying cost trajectory or system value of the technology. First, capital cost adders derived from SB 423 impose a 20 percent premium on hydrogen combustion turbines and a 10 percent heat rate penalty through 2035, relative to the NRL ATB 2024 baseline. These are fixed inputs that prevent hydrogen combustion turbines from competing in least-cost optimization against resources whose costs decline endogenously. Second, no scenario is designed to test the system value of fast-ramping, dispatchable hydrogen generation. The reliability services hydrogen combustion turbines provide; sub-hourly ramping, black start capability, in-basin firm capacity in transmission-constrained load pockets, and multi-day storage dispatch through geologic storage, are not directly valued in the capacity expansion stage. Third, no scenario tests the system cost difference between a portfolio that includes hydrogen combustion turbines and one that does not, holding all else equal. The 2021 SB 100 Report's generic zero-carbon firm resource scenario demonstrated a $2 billion system cost reduction when approximately 15 gigawatts of clean firm capacity was added to the portfolio. The 2025 modeling includes no equivalent analysis.

There is evidence that hydrogen is a key resource for maintaining system reliability in a decarbonized system. LADWP's LA100 Study concluded that green hydrogen turbines are necessary infrastructure to ensure reliability and resiliency of a 100 percent clean grid, providing backup during peak demand, low renewable output, and transmission disruption caused by wildfires, earthquakes, or extreme weather. The 2022 LA100 Plan examined whether fuel cells could substitute for hydrogen turbines at gigawatt scale in a transmission-constrained urban environment and found that fuel cells are significantly costlier, roughly four times the capital cost assumed for green hydrogen turbines, at the scale required for thermal generating facilities. This finding is directly relevant to the Combustion Retirement scenario's selection of five gigawatts of hydrogen fuel cells: LADWP's own analysis suggests the fuel-cell-only approach may be materially more expensive than a mixed portfolio at this scale, and the comparison has not been conducted in the current modeling.

LADWP's Scattergood Energy Center hydrogen conversion project, a planned retrofit of an existing coastal gas generating facility to operate on green hydrogen, demonstrates that hydrogen combustion generation is an active utility investment in California today, not a speculative future scenario.[6] The Scattergood project provides a real-world cost and timeline benchmark for hydrogen combustion turbine retrofits that should inform future SB 100 capital cost assumptions, replacing the SB 423 adder-based estimates with California-specific project data as it becomes available.

[5] California Energy Commission. (2026, March 9). SB 100 Inputs and Assumptions [Presentation]. Docket No. 23-SB-100. https://efiling.energy.ca.gov/GetDocument.aspx?tn=268979&DocumentContentId=106173.

[6] California Energy Commission. (2024, April 16). 2025 Senate Bill 100 Report Non-Energy Benefits: LADWP Presentation [Presentation]. Docket No. 23-SB-100, TN 255713. https://efiling.energy.ca.gov/GetDocument.aspx?tn=255713&DocumentContentId=91542.

IV. Transportation Hydrogen Demand Scenarios Understate California's Adopted Policy Trajectory

The Higher Hydrogen Demand scenario is calibrated at 85 percent of the 2022 Scoping Plan's hydrogen transportation demand projection, below the state's own adopted planning target. The Scoping Plan level should be the baseline against which higher and lower sensitivities are tested, not a ceiling the high scenario fails to reach. The consequence of these planning assumptions is in the Joint Agencies presentation: i.e., approximately one gigawatt of additional resource selection. This finding reflects calibration choices rather than any meaningful signal about hydrogen's system relevance at the scale California's own policy requires.

California's adopted zero-emission vehicle mandates independently establish a minimum trajectory for hydrogen demand that the current scenarios do not reflect. The Advanced Clean Cars II, Advanced Clean Trucks, Advanced Clean Fleets, and Innovative Clean Transit regulations create durable procurement signals for fuel cell electric vehicles across light-, medium-, and heavy-duty applications.[7] These mandates are reinforced by the December 2023 SB 671 Clean Freight Corridor Efficiency Assessment, a multi-agency report prepared with CARB, CEC, CPUC, Caltrans, and GO-Biz, which identifies 34 Priority Freight Corridors for zero-emission deployment, explicitly includes hydrogen fueling as a necessary infrastructure component, and estimates $10 to $15 billion in infrastructure investment along the six highest-priority corridors alone by 2035.[8] The current station development timeline of six to eight years per station means the investment decisions that determine 2030 and 2035 hydrogen demand are being made in the current planning cycle. The SB 100 modeling should reflect the full policy-mandated demand trajectory now rather than deferring to a future cycle.

CHC acknowledges that Congressional Review Act actions targeting Advanced Clean Cars II, Advanced Clean Trucks, and Advanced Clean Fleets create material uncertainty for the regulatory floor identified above. California's transportation decarbonization commitment is grounded in AB 32, SB 375, and Executive Order N-79-20, state law and executive authority that remain intact regardless of federal action. The appropriate analytical response to this uncertainty is not to reduce modeling ambition but to expand it. The 2029 modeling cycle should include both a full mandate implementation scenario and a federal disruption sensitivity, allowing policymakers to understand what state-level action is required to maintain California's hydrogen transportation trajectory under either federal policy outcome.

Pipeline blending, the introduction of hydrogen into the existing natural gas distribution system, represents an additional demand pathway that is entirely absent from the current modeling. For CHC's members in production and midstream, blending creates a large, geographically distributed, continuous hydrogen demand that is decoupled from vehicle adoption and station economics constraints, providing a critical near-term mechanism for achieving the production volumes necessary to drive down costs. The current modeling treats 1,500 megawatts of POU-planned hydrogen blending in the Reference scenario as a fixed planned resource inherited from LSE plans, not as a modeled choice or a mechanism that

[7] California Air Resources Board. (2022). 2022 Scoping Plan for Achieving Carbon Neutrality. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

[8] California Transportation Commission. (2023, December 6). SB 671 Clean Freight Corridor Efficiency Assessment. https://catc.ca.gov/-/media/ctc-media/documents/programs/sb671/sb671-final-clean-freight-corridor-efficiency-assessment-dor.pdf.

interacts with production economics. No scenario tests what increased blending penetration would do to system costs, gas sector emissions, or hydrogen production economics.

V. The Modeling Framework's Treatment of Hydrogen Delivery Infrastructure Structurally Disadvantages Hydrogen

The SB 100 modeling applies a fixed $10 per million British thermal unit adder for intra-regional hydrogen distribution, sourced from Argonne's Hydrogen Delivery Scenario Analysis Model, with hydrogen storage costs from an EPRI report the Inputs and Assumptions filing acknowledges is not California-specific. No pipeline infrastructure, its capital costs, capacity, geographic routing, or economies of scale, is represented anywhere in the framework. This assumption is not applied to any other resource. Solar, wind, and battery resources are modeled with California-specific resource potentials and capacity factors. Natural gas benefits from sunk pipeline infrastructure costs. Offshore wind receives California-specific grid connection cost adders developed from CAISO Transmission Planning Process studies. Hydrogen alone is evaluated against a generic, volume-invariant distribution cost that cannot represent what hydrogen costs when delivered by pipeline at scale. SoCalGas raised this concern in March 2024, noting that assuming on-site hydrogen production and storage may artificially limit the model's ability to select hydrogen resources.[9]

LADWP's Angeles Link project, a proposed 220-mile large-diameter hydrogen pipeline from the Mojave Desert to the Los Angeles Basin designed to deliver up to 28,000 metric tons of green hydrogen annually, directly enables the Scattergood Energy Center hydrogen conversion and would simultaneously serve power generation, industrial customers, and heavy-duty fueling corridors along the I-710 and I-5. Angeles Link represents exactly the kind of multi-use hydrogen delivery infrastructure the model cannot represent. Its development timeline of approximately a decade means that planning decisions made in the current cycle determine whether it is available to serve 2035 and 2040 system needs. A final report that cannot represent pipeline infrastructure cannot provide meaningful guidance on whether infrastructure investments at this scale and type are warranted.

The draft results identify winter reliability as the binding constraint across all scenarios, requiring overnight gas generation, sustained imports, and in the Combustion Retirement scenario an additional two hundred terawatt-hours of total generation. Hydrogen stored in geologic formations and dispatched through pipeline infrastructure to generators during winter low-renewable periods is the most direct technological analog to the seasonal firm capacity the gas system currently provides, and the only one that can be fully decarbonized. The Green Hydrogen Coalition's November 2023 comments in this proceeding, drawing on its HyBuild LA analysis, established that achieving less than $2 per kilogram of delivered green hydrogen in Los Angeles requires shared pipeline transport connected to out-of-state geologic storage.[10] The model's inability to represent this infrastructure means the report cannot provide a complete evaluation of hydrogen's potential seasonal storage contribution, precisely the contribution most needed to solve the winter reliability problem the report itself identifies.

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[9] Southern California Gas Company. (2024, March 1). SoCalGas Comments on the SB 100 Inputs and Assumptions Workshop. Docket No. 23-SB-100, TN 254782. https://efiling.energy.ca.gov/GetDocument.aspx?tn=254782&DocumentContentId=90419.

[10] Green Hydrogen Coalition. (2023, November 14). Green Hydrogen Coalition Responses to the SB 100 Analytical Framework Workshop. Docket No. 23-SB-100, TN 253105. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253105&DocumentContentId=88309.

VI. Non-Energy Benefits of Hydrogen Scenarios Are Substantially Underdeveloped

The non-energy benefits analysis assesses hydrogen's contributions primarily through avoided electricity sector criteria pollutant emissions and the social cost of avoided greenhouse gases. These are meaningful metrics, but they capture only a fraction of the co-benefits that hydrogen production and end use generate for California's broader environmental and climate goals. By focusing exclusively on electricity sector emissions, the framework systematically excludes the upstream benefits of biogenic hydrogen production pathways, which are among the most significant contributions hydrogen can make to California's carbon neutrality strategy.

Lawrence Livermore National Laboratory's Getting to Neutral report identifies gasifying biomass to make hydrogen as holding the largest promise for carbon dioxide removal at the lowest cost among California's waste biomass conversion pathways.[11] Approximately 56 million bone-dry tons of waste biomass are available annually in California from municipal solid waste, agricultural residue, forest management residue, sawmill waste, and gaseous waste from landfills, dairies, and wastewater treatment, converting this resource to hydrogen while capturing process carbon dioxide represents approximately 84 million metric tons per year of negative emissions, the largest single contributor to California's 125 million metric ton annual carbon removal requirement. The non-energy benefits of hydrogen production scenarios that incorporate these feedstocks include landfill organic waste diversion consistent with California's SB 1383 Short-Lived Climate Pollutant Reduction Strategy targets,[12] elimination of open-field burning of agricultural waste with associated reductions in PM2.5 and NOx, reduction in wildfire risk through economic offtake of forest thinning residue, and methane mitigation across dairy, landfill, and wastewater source categories that directly implements the Short-Lived Climate Pollutant Reduction Strategy's anthropogenic methane targets.[13] None of these co-benefits appear in the current non-energy benefits framework.

The transportation sector health benefits of hydrogen fuel cell vehicle deployment also substantially exceed the electricity sector health gains the current analysis captures. The SB 671 Assessment estimates that transitioning the six highest-priority freight corridors to zero-emission operation reduces diesel-related PM2.5 and NOx by approximately 23 percent in 2030 and 53 percent in 2040, with a potential reduction of 1,720 premature deaths through 2040 and approximately $18.6 billion in statewide health savings under full Advanced Clean Fleets implementation. These benefits are larger than the electricity sector health gains the current analysis captures and are directly attributable to zero-emission fuel cell vehicles whose tailpipe emissions are zero.

[11] Baker, S. E., Stolaroff, J. K., Peridas, G., Pang, S. H., Goldstein, H. M., Lucci, F. R., Li, W., Slessarev, E. W., Pett-Ridge, J., Ryerson, F. J., Wagoner, J. L., Kirkendall, W., & Aines, R. D. (2020). Getting to Neutral: Options for Negative Carbon Emissions in California. Lawrence Livermore National Laboratory. LLNL-TR-796100. https://gs.llnl.gov/sites/gs/files/2021-08/getting_to_neutral.pdf

[12] SB 1383 (Lara, Chapter 395, Statutes of 2016).

[13] California Air Resources Board. (2020). Short-Lived Climate Pollutant Reduction Strategy. https://ww2.arb.ca.gov/our-work/programs/short-lived-climate-pollutants

VI. Consolidated Requests

A. Structural modeling limitations:

1. The final report should clearly state that the Combustion Retirement scenario's selection of five gigawatts of hydrogen fuel cells represents the model's own validation that there is no pathway to full combustion retirement without hydrogen-based firm generation, and frame this finding prominently rather than as an outlier result.

2. Distinguish between the modeling result that hydrogen resources are not economically selected and any broader conclusion about hydrogen's cost competitiveness, acknowledging that the former reflects fixed cost assumptions and scenario design rather than an independent market finding.

3. Acknowledge that the 2021 SB 100 Report's recommendation to continue evaluating clean and renewable hydrogen technologies and demand flexibility has not been fully addressed in the current cycle and commit to specific methodological improvements for the 2029 modeling cycle.

B. Hydrogen combustion turbines:

4. Acknowledge that hydrogen combustion turbines are not economically selected because of fixed SB 423 capital cost adders and the absence of scenarios designed to value fast-ramping reliability services, not because of an independent finding about cost competitiveness.

5. Acknowledge that the Combustion Retirement scenario's selection of five gigawatts of hydrogen fuel cells has not been compared against a mixed portfolio including hydrogen combustion turbines for the same reliability function, and that LADWP's SLTRP analysis suggests the fuel-cell-only approach may be materially more costly at gigawatt scale.

6. Recommend that the 2029 modeling cycle include updated hydrogen combustion turbine capital cost assumptions informed by California project data, including Scattergood. The 2029 modeling cycle should include a scenario comparing fuel-cell-only versus mixed hydrogen generation portfolios for combustion retirement applications, and a formal zero-carbon resource definition encompassing renewable-hydrogen-fueled combustion generation.

C. Regarding transportation hydrogen demand:

7. Disclose in the final report that the Higher Hydrogen Demand scenario is calibrated at 85 percent of the Scoping Plan's hydrogen transportation demand projection, and that its findings do not represent the system implications of achieving the Scoping Plan's hydrogen goals.

8. Acknowledge that California's adopted ZEV mandates and the multi-agency SB 671 Clean Freight Corridor Efficiency Assessment establish a regulatory and planning floor for transportation hydrogen demand that should be reflected as a minimum baseline in future scenarios rather than as a sensitivity.

9. Recommend that the 2029 modeling cycle include a transportation hydrogen demand scenario calibrated at or above the Scoping Plan projection, a sensitivity testing full ZEV mandate

implementation, a federal disruption sensitivity reflecting potential mandate curtailment, and a pipeline blending scenario calibrated to levels under active consideration in CPUC proceedings.

D. Hydrogen delivery infrastructure:

10. Acknowledge that the current modeling's generic, non-California-specific distribution cost adder structurally disadvantages hydrogen relative to resources whose delivery infrastructure is either sunk or modeled with California-specific data, and that findings about hydrogen cost competitiveness should be understood in this context.

11. Acknowledge the Angeles Link and the broader class of large-scale hydrogen pipeline projects under active development as planned infrastructure with material implications for hydrogen cost, reliability, and seasonal storage that the current modeling framework cannot capture.

12. Recommend that the 2029 modeling cycle develop California-specific hydrogen infrastructure cost and capacity assumptions in coordination with entities with active hydrogen pipeline programs and include a scenario that models a hydrogen pipeline backbone connecting large-scale renewable production with demand centers and geologic storage.

E. Regarding non-energy benefits:

13. Acknowledge that the current non-energy benefits framework excludes the most significant co-benefits of biogenic hydrogen production, including landfill organic waste diversion consistent with SB 1383 targets, agricultural waste elimination, wildfire risk reduction through forest biomass offtake, and anthropogenic methane mitigation across dairy, landfill, and wastewater source categories, and commit to developing methodology to assess these co-benefits in the 2029 cycle.

14. Incorporate the LLNL Getting to Neutral report's finding that biomass gasification to hydrogen represents the largest and lowest-cost negative emissions pathway in California's waste biomass conversion portfolio, with approximately 84 million metric tons per year of negative emissions potential from biomass conversion overall, as context for the non-energy benefits of hydrogen production scenarios in the final report.

15. Expand the non-energy benefits analysis to incorporate the transportation sector public health benefits of hydrogen fuel cell vehicle deployment in the heavy-duty freight, transit, and off-road sectors, drawing on the SB 671 Assessment's findings regarding premature death reduction and health cost savings attributable to diesel displacement.

VII. Conclusion

California's path to carbon neutrality requires treating hydrogen as a planned and essential resource, not as a residual technology that the model reaches for only when all other options are exhausted. The draft modeling results, as currently structured, cannot support that treatment, not because hydrogen is uncompetitive, but because the modeling framework is not designed to reveal hydrogen's value. The final SB 100 Report should acknowledge these limitations with precision, and the 2029 modeling cycle should address them with specific methodological improvements.

CHC thanks the Joint Agencies for the opportunity to submit these comments and commends CEC staff for the quality and transparency of the workshop materials and Inputs and Assumptions filing. CHC looks forward to continued engagement as the Joint Agencies develop the final report and plan for the 2029 modeling cycle and stands ready to provide technical support and California-specific project data to assist in developing an improved hydrogen modeling framework.

Respectfully submitted,

_______/s/_____
Teresa Cooke
Executive Director
California Hydrogen Coalition
March 20, 2026