Date of Hearing: March 22, 2023

ASSEMBLY COMMITTEE ON UTILITIES AND ENERGY
Eduardo Garcia, Chair
AB 324 (Pacheco) – As Introduced January 30, 2023

SUBJECT: Gas corporations: renewable gas procurement

SUMMARY: Establishes a definition of "renewable hydrogen," and requires the California Public Utilities Commission (CPUC) to consider renewable hydrogen procurement goals for each gas corporation and transporter, as specified, on a proportionate basis. Specifically, **this bill**:

1) Defines "renewable hydrogen" to mean any of the following:

    a. A production process that uses electricity that is consistent with the Renewables Portfolio Standard (RPS) Program.

    b. A production process that uses energy, other than electricity, produced from a specified list of resource types.

    c. A production process that uses material feedstock that is either water or material from a specified list of resource types.

    d. For a production process that uses landfill gas or digester gas to generate an energy input or to provide feedstock, that the procurement of that gas is consistent with biomethane eligibility rules for RPS participation.

    e. For a production process that uses biomass to generate energy input or provide feedstock, that it is by biomass conversion; and, for forest waste biomass, is consistent with CPUC guidelines defining byproducts of sustainable forestry.

    f. Any other process yielding hydrogen from only renewable inputs, as determined by the CPUC.

2) Mandates the CPUC to open a new proceeding, or new phase of an existing proceeding, to consider establishing renewable hydrogen procurement goals for each gas corporation and transporter, and require each to annually procure a proportionate share of renewable hydrogen to meet the procurement goals.

3) Mandates the CPUC to make the following findings before establishing renewable hydrogen procurement targets or goals:

    a. The targets or goals are a cost-effective means of achieving the forecasted reduction in the emissions of short-lived climate pollutants and other greenhouse gases (GHGs).

b. The targets or goals comply with all applicable state and federal laws.

c. The safety risk of using renewable hydrogen in pipelines will be appropriately regulated, mitigated, and monitored. Prohibits the use pipelines for hydrogen until the CPUC acts to set safety standards and the pipelines meet those standards.

d. Combustion end uses that may be affected by the addition of hydrogen to the pipelines are appropriately regulated and controlled to avoid increased emissions.

EXISTING LAW:

1) Defines "gas corporation" to include every corporation or person owning, controlling, operating, or managing any gas plant for compensation within this state, with exceptions. (Public Utilities Code § 222)

2) Defines "core transport agent" to include an entity that offers core gas procurement service to customers within the service territory of a gas corporation, but does not include a gas corporation, and does not include a public agency that offers gas service to core and noncore gas customers within its jurisdiction, or within the service territory of a local publicly owned gas utility. "Core transport agent" includes the unregulated affiliates and subsidiaries of a gas corporation. (Public Utilities Code § 980(b))

3) Defines "green electrolytic hydrogen" as hydrogen gas produced through electrolysis and does not include hydrogen gas manufactured using steam reforming or any other conversion technology that produces hydrogen from a fossil fuel feedstock. The statutory definition does not specify the type of energy input needed to drive the electrolytic reaction; thus any energy input would qualify under this definition. (Public Utilities Code § 400.2)

4) Defines "clean hydrogen" as hydrogen produced from eligible renewable energy resources, as defined within the RPS, and otherwise consistent with the federal standard set for carbon intensity of clean hydrogen production, or as that federal standard is revised or supplemented by CARB. (Government Code § 12100.161)

5) Establish a Hydrogen Program within the California Energy Commission (CEC) to provide financial incentives to in-state hydrogen projects, so long as the projects are "derived from water using eligible renewable energy resources, as defined, or produced from these eligible renewable energy resources." (Public Resources Code §§ 25664-25664.1)

6) Requires the CPUC, the CEC, and the California Air Resources Board (CARB) to consider green electrolytic hydrogen an eligible form of energy storage and consider its potential uses. (Public Utilities Code § 400.3)

7) Requires the CPUC, in consultation with CARB, to consider adopting specific biomethane procurement targets or goals for each gas corporation. (Public Utilities Code § 651)

8) Requires the CPUC and CEC to undertake specified actions to advance the state's clean energy and pollution reduction objectives, including, where feasible, cost effective, and consistent with other state policy objectives, increasing the use of large- and small-scale energy storage with a variety of technologies, including green electrolytic hydrogen, as defined. (Public Utilities Code § 400)

9) Establishes a RPS Program requiring certain percentages of electricity retail sales be served by renewable resources, most recently increased by SB 100 (De Leon, Chapter 312, Statutes of 2018) to 60% by 2030 and a state goal of procuring 100% of electricity from eligible renewable energy resources and zero-carbon resources by December 31, 2045. Existing law requires state agencies, including the CPUC, CEC, and CARB, to take certain actions to support these clean energy goals. (Public Utilities Code § 399.11)

10) Specifies that facilities using biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current qualify as RPS eligible facilities, if they meet other qualifying criteria as specified. (Public Resources Code § 25741)

FISCAL EFFECT: Unknown. This bill is keyed fiscal and will be referred to the Assembly Committee on Appropriations for its review.

BACKGROUND:

The Hydrogen Color Wheel – Hydrogen has been considered the "swiss army knife" of decarbonization technologies; praised for its touted zero-GHG profile and potential to replace fossil fuels in most applications relatively easily. However, there are many types of hydrogen with varying levels of climate benefits. The type of feedstock (what material is used to make the hydrogen) and the production method (what is done to break apart the feedstock into hydrogen) plays a significant role in determining the lifecycle emissions associated with hydrogen use.

Some notable feedstocks of hydrogen include biomass, biomass-derived liquids like ethanol and bio-oil, biogas, coal, natural gas, and water. These feedstocks are then broken down through thermochemical processes to generate hydrogen. The thermochemical processes vary and can generate different amounts and types of particulate pollution and GHGs. In every process, energy is needed in order to generate hydrogen. Some processes rely on clean resources exclusively for their power, while others are less discriminating. The combinations of feedstocks and processes result in a multitude of hydrogen products. A simplified color spectrum has been adopted to describe these hydrogen products; however, the definitions of these colors are neither universally agreed upon nor rigorous.

- "Gray (or brown) hydrogen" is produced from a natural gas feedstock and whatever energy is cheapest, via natural gas steam methane reforming. **The vast majority of hydrogen currently used in the United States comes from this process.** While cheap and efficient, it generates carbon dioxide and other pollutants, depending on the energy source used.
- "Blue hydrogen" employs the same process as gray hydrogen, but the carbon dioxide emitted from steam methane reforming is captured and stored, lessening the GHG impact of this process.
- "Turquoise hydrogen" uses a natural gas feedstock, which is passed through molten metal to split the natural gas into hydrogen and solid carbon.
- "Green hydrogen" is produced using only renewable feedstock – such as biomass, renewable natural gas, or water – and typically (but not always) relies on renewable electricity to generate the hydrogen. Less than 0.1 percent of hydrogen production globally comes from water electrolysis. In the future, policymakers should approach the "green" hydrogen label with caution, as new definitions for green hydrogen are developed, and may not always include electrolytic production with no carbon release.
- "Green electrolytic hydrogen" is a specific type of green hydrogen which uses water as the feedstock and renewable electricity to split the water in order to generate hydrogen. Green electrolytic hydrogen is currently the only type of hydrogen defined in the Public Utilities Code (Public Utilities Code § 400.2). However, its statutory definition does not specify that renewable electricity must be used to split the water, making it only partially "green" in the traditional sense.
- "Pink hydrogen" refers to a specific type of green electrolytic hydrogen where only nuclear energy is used to split the water.
- "Yellow hydrogen" refers to a specific type of green electrolytic hydrogen where only solar energy is used to split the water.

As the Color Wheel indicates, any conversation about hydrogen is heavily dependent upon the color and precise definition of that color being discussed. With so many colors and so many loose definitions, it is easy to misunderstand or misascribe the climate benefits when discussing hydrogen.

What Do We Do With All the H_2? Hydrogen has the potential to be used in a multitude of applications – from fuel cells in cars; to replacing natural gas in homes; to fuel replacement in aviation, shipping, and trucking industries; and to generate electricity. One, much discussed, potential application of hydrogen is to firm our renewable energy grid. By using low-cost, abundant electricity from intermittent renewables during the day (i.e. solar and wind) to produce hydrogen, and then using that hydrogen in fuel cells or injecting into a pipeline to provide power at other times, hydrogen can act as a form of storage. However, in practice, many of the technologies used to produce hydrogen from renewables are still expensive and unable to economically cycle on and off in line with the availability of intermittent renewables. This example in the energy sector is characteristic of many other hydrogen applications – where the

GHG footprint, cost, and availability of the hydrogen are uncertain or unclear – calling for a more thorough understanding of which hydrogen product is best suited to which application.

Following the passage of SB 1075 (Skinner, Chapter 363, Statutes of 2022), CARB, the CPUC, and the CEC are evaluating the possible deployment, development, and uses of hydrogen in the state. The evaluation is mandated to be publicly posted by June 1, 2024. CARB must also consult with the California Workforce Development Board and labor and workforce organizations on the evaluation. SB 1075 also requires the CEC to study and model potential growth for hydrogen and its role in decarbonizing the electrical and transportation sectors of the economy as part of the 2023 and 2025 editions of its Integrated Energy Policy Report.

Hydrogen in the Pipeline – The end-uses for hydrogen will strongly depend on reliable methods for safely storing and transporting it in large quantities. It is not as simple as injecting hydrogen directly into the natural gas pipeline. Hydrogen can embrittle and crack gas pipeline materials.[1] Older pipelines may be compromised as the percentage of hydrogen in the pipeline increases, due to the operating pressure of the pipeline needing adjustment to accommodate the smaller gas.[2]

While hydrogen is not explicitly barred from the pipeline, the CPUC's Standard Renewable Gas Interconnection Tariff currently limits the amount of pure hydrogen gas concentration injected into the intrastate pipeline to 0.10%.[3] Any concentration above that amount would pass the "trigger level,[4]" and testing for hydrogen concentration must for done for all sources of biomethane without exception. As a result, pure hydrogen is currently not injected into the common carrier pipeline. However, the CPUC has had a $1.5 million contract with the University of California Riverside and the Gas Technology Institute to conduct experimental work on the safety and efficacy of injecting hydrogen into California's pipelines.[5] In July 2022, researchers issued their final report finding[6]:

- Hydrogen blends of up to 5% in the natural gas stream are generally safe. However blending more hydrogen in gas pipelines overall results in a greater chance of pipeline leaks and the embrittlement of steel pipelines.

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[1] Hafsi, Z., Mishra, M., and Elaoud, S., "Hydrogen embrittlement of steel pipelines during transients," *Procedia Structural Integrity*, Vol. 13, 2018, pg. 210-217.
[2] Penev, M., Zuboy, J., and Hunter, C.,"Economic analysis of a high-pressure urban pipeline concept (HyLine) for delivering hydrogen to retail fueling stations," *Transportation Research Part D: Transport and Environment*, Volume 77, 2019, pg. 92-105.
[3] D. 20-08-035; "Decision Adopting the Standard Renewable Gas Interconnection Tariff;" R. 13-02-008; CPUC; September 4, 2020.
[4] A "trigger level" denotes a threshold measured value of a constituent, when exceed will trigger additional periodic testing and analysis.
[5] UC Riverside Center for Environmental Research and Technology, "Hydrogen Impacts Study;" April 2020-September 2021. https://www.cert.ucr.edu/hydrogen-impacts-study
[6] Raju, A., Martinez-Morales, A., and Lever, O.; *Hydrogen Blending Impacts Study*; CPUC Final Report; filed July 18, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

- Hydrogen blends above 5% could require modifications of appliances such as stoves and water heaters to avoid leaks and equipment malfunction.
- Hydrogen blends of more than 20% present a higher likelihood of permeating plastic pipes, which can increase the risk of gas ignition outside the pipeline.
- Due to the lower energy content of hydrogen gas, more hydrogen-blended natural gas will be needed to deliver the same amount of energy to users compared to pure natural gas.

Despite these findings, in December 2022, the CPUC ordered California's gas corporations to launch pilot projects studying the safety impacts of blending hydrogen into the methane pipeline system, with the hydrogen blend making up to 20% of the gas in the system.[7] The Decision ordered the gas corporations to file an application proposing their pilots by December 2024. The Decision also established an interim "clean renewable hydrogen" definition as emitting no more than "4 kilograms (kg) of carbon dioxide equivalent (CO_2e) per kg of hydrogen produced on a life-cycle basis and not using fossil fuel as a feedstock or production energy source."[8] That definition matches the definition for clean hydrogen eligible for federal production incentive payments as established in the Inflation Reduction Act of 2022, while adding a loosely defined "renewable" standard that is ultimately contingent on further deliberation. Importantly, the prohibition on the use of fossil fuel in this "clean renewable hydrogen" definition does not apply to an eligible renewable energy resource that uses a de minimis quantity of fossil fuel, as allowed under PUC § 399.12(h)(3).

The Biomethane Template – Since 2013, the CPUC has had an ongoing rulemaking examining safety and pipeline open access rules, as they relate to biomethane injection into the common carrier pipeline.[9] Analysis by CARB, the Office of Environmental Health Hazard Assessment,[10] and the California Council on Science and Technology[11] answered many of the outstanding questions of safe injection of biomethane. With many of the safety issues resolved, the Legislature directed[12] the CPUC to consider biomethane procurement goals for gas corporations. In February 2022, the CPUC adopted biomethane procurement targets of 17.6 billion cubic feet annually by 2025 and 72.8 billion cubic feet annually by 2030.[13] For context, California's

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[7] D. 22-12-057. "Decision Directing Biomethane Reporting and Directing Pilot Projects to Further Evaluate and Establish Pipeline Injection standards for Clean Renewable Hydrogen;" R. 13-02-008; December 19, 2022.
[8] Order paragraph #4, pg. 67, D. 22-12-057. *Ibid.*
[9] R.13-02-008 "Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions." CPUC, February 21, 2013.
[10] CARB and OEHHA; "Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline;" May 15, 2013; https://oehha.ca.gov/media/final_ab_1900_staff_report_appendices_051513.pdf
[11] CCST, *Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications*; June 2018; https://ccst.us/wp-content/uploads/2018biomethane.pdf.
[12] SB 1440 (Hueso, Chapter 739, Statutes of 2018)
[13] D. 22-02-025; CPUC; *Decision Implementing Senate Bill 1440 Biomethane Procurement Program*; February 24, 2022.

average natural gas demand in 2020 was approximately 2 trillion cubic feet annually.[14] Hydrogen injection standards or procurement was not ordered as part of this decision.

Rather, in November 2019, the CPUC issued a Scoping Memo in the proceeding to develop a hydrogen gas pipeline injection standard, among other considerations. This standard will specify how much hydrogen gas can be blended into the existing gas pipeline system in California without compromising pipeline integrity and safety. It is through this rulemaking that the pilot projects on hydrogen blending mentioned above were ordered.

COMMENTS:

1) *Author's Statement.* According to the author, "AB 324 aims to decrease the price of renewable hydrogen through procurement mandates of this important energy source. Following a process similar to California's Renewable Portfolio Standard (RPS), the goals is to jump start production to decarbonize the existing natural gas system and lower the cost of the fuel for a potential dedicated hydrogen system in the future. Diversifying the utilities' renewable procurement portfolios to include hydrogen reduces risk, improves California's chances of reaching its ambitious carbon-neutrality goals, increase competition between decarbonization pathways, and provides Californians access to a decarbonization pathway that many expect to provide lower long-term costs. We know that achieving carbon neutrality will be quite a challenge, but as legislators, it's our responsibility to clear a path for new technologies that will improve the lives of all Californian's."

2) *Is this renewable?* This bill proposes a definition for "renewable hydrogen" that lists certain energy inputs and feedstocks that would qualify hydrogen derived from them as "renewable hydrogen." While providing the veneer of being renewable, as the definition cites RPS-eligible energy resources throughout, the operative language that "any" of the combinations of energy or feedstock would ensure eligibility opens this definition up to fossil fuel inputs and renewable sources that aren't actually delivered in or to California. As noted above, there are many types and colors of hydrogen. Calling hydrogen "renewable" when non-renewable resources can be used is misleading. As such, *the author and committee may wish to consider modifying the definition of "renewable hydrogen" used in this bill to clarify that only renewable electricity and feedstock may be used.*

3) *Cost Considerations.* As discussed recently in an informational hearing of this Committee, the cost of natural gas procurement has been extraordinarily high this winter. In December prices at both Pacific Gas & Electric CityGate and SoCal CityGate

[14] 2020 total consumption reported at 2.074 trillion cubic feet; U.S. Energy Information Administration, "Natural Gas Consumption by End Use;" https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCA_a.htm ; accessed 06.17.2022

exceeded or nearly exceeded $50 per million British thermal units (MMBtu).[15] For context, the past few years have seen natural gas prices hovering between $5-$10/MMBtu at the SoCal CityGate hub. While these spikes in cost of fossil natural gas procurement are troubling, they foreshadow a growing trend of natural gas unaffordability, with natural gas rates—not just commodity prices—increasing. Moreover, recent efforts to decarbonize the natural gas system with biomethane procurement have the likely impact of further raising natural gas costs.

As mentioned above, in February 2022, the CPUC adopted biomethane procurement targets for 2025 and 2030.[16] The 2030 target reflected approximately 12% of the residential and small business natural gas usage in 2020. In the Decision, the CPUC reported that the average cost of biomethane was $17.70/MMBtu, far more costly than the average cost of fossil natural gas at $9.40/MMBtu.[17] The Decision didn't set a price cap on biomethane procurement, but did require the gas utilities to seek CPUC review if prices exceeded $26/MMBtu, what the CPUC determined as the "social cost" of methane.[18]

Importantly, the legislation the CPUC was implementing with this procurement order, SB 1440 (Hueso, Chapter 739, Statutes of 2018), directed the CPUC to "*consider* adopting specific biomethane procurement targets;" similar to this bill's requirement that the CPUC "*consider* establishing renewable hydrogen procurement goals." While this consideration is not an obligation of the CPUC to issue procurement orders, the recent work in the SB 1440 proceeding suggests that hydrogen procurement orders may be likely should this bill be chaptered. Recent analysis suggests electrolytic hydrogen could range between ~$16-$25/MMBtu, not accounting for storage or transportation costs,[19] an increase in cost over both fossil natural gas and biomethane.

While decarbonization of the natural gas system is important to meeting many of our statewide climate goals, it is occurring concurrently with local efforts to ban natural gas connections to new developments, and even in some retrofits.[20] Such restrictions could have the unintended consequence of shifting the cost of maintaining the natural gas system to a smaller pool of customers, leading to inequities and unaffordable natural gas bills for those who remain. A statewide strategy to contemplate selective pruning of the

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[15] Energy Information Administration's *Natural Gas Weekly*, December 22, 2022.
[16] D. 22-02-025, *Decision Implementing Senate Bill 1440 Biomethane Procurement Program,* R. 13-02-008, February 24, 2022; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF
[17] Average natural gas price in California in 2021; U.S. Energy Information Administration, "California Natural Gas Industrial Price", https://www.eia.gov/dnav/ng/hist/n3035ca3A.htm
[18] Order # 13, pg. 59, D. 22-02-025, *Ibid.*
[19] Lazard's *Levelized Cost of Hydrogen Analysis,* 2021; https://www.lazard.com/media/451779/lazards-levelized-cost-of-hydrogen-analysis-vf.pdf
[20] Morgan Evans, "Another California County Bans Natural Gas Hookups 'Beyond State Code,'" *Natural Gas Intelligence*, December 7, 2022. https://www.naturalgasintel.com/another-california-county-bans-natural-gas-hookups-beyond-state-code/

natural gas system or take a critical eye toward future infrastructure development,[21] may be a prudent approach to dealing with these competing, and costly, forces within the natural gas system. The CPUC has begun examining these issues in their Long-Term Gas System Planning proceeding,[22] but a comprehensive strategy has yet to materialize.

4) *Who is in charge of the infrastructure?* While this bill calls for the consideration of hydrogen procurement, it is less clear around questions of the ownership and oversight of the associated infrastructure to develop the hydrogen. The utilities could meet targets that may be established pursuant to this bill with contracts from hydrogen developers to inject low percentages of hydrogen within their existing common carrier pipelines, or the utilities could achieve hydrogen procurement through their own hydrogen generation and build-out of dedicated infrastructure. No clear pathway is outlined nor guaranteed. Some existing hydrogen generators have raised concern about the language in the bill—especially the provision forbidding any hydrogen transport via pipelines until the CPUC acts to set safety standards for the pipelines—as these producers already own and operate *dedicated* hydrogen pipelines within the state. They view these provisions as shutting down existing hydrogen transport.

   The federal Pipeline & Hazardous Materials Safety Administration (PHMSA) has exclusive authority over interstate pipeline facilities,[23] and has regulated hydrogen transport since the 1970s.[24] However, no state agency is clearly "in charge" of dedicated hydrogen pipelines. The CPUC regulates intrastate *gas* pipelines, inclusive of both natural gas and liquid petroleum gas. So if hydrogen is being injected as a blend into the common carrier pipeline, which transports natural gas to customers, then the CPUC's jurisdiction to regulate the safety of those pipelines seems apparent. But questions have been raised whether the CPUC has the authority to regulate *dedicated* hydrogen pipelines, and whether it can approve such *dedicated* pipelines for cost recovery from gas utility ratepayers.

   Recently, the CPUC approved SoCalGas's Application to record the costs of studying the feasibility of building a *dedicated* renewable hydrogen pipeline serving the Los Angeles Basin (the "Angeles Link").[25] SoCalGas estimated that engineering and design work will last through 2025, with the full build-out of such a pipeline—if it receives CPUC approval—occurring in 2035. The author may wish to consider clarifying within this bill the CPUC's authority to regulate the safety and cost-effectiveness of both dedicated and common carrier pipelines transporting hydrogen, prior to any procurement targets being considered.

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[21] Ted Lamm and Ethan Elkind,"Building Toward Decarbonization," *Berkeley Law Policy Report,* January 2021.
[22] R. 20-01-007
[23] 49 USC § 60101, et seq.
[24] https://primis.phmsa.dot.gov/comm/hydrogen.htm
[25] D.22-12-055

5) *Related Legislation.*

AB 1550 (Bennett, 2023) mandates that by January 1, 2045, all hydrogen produced and used in California for the generation of electricity or fueling of vehicles shall be green hydrogen (undefined). Status: *pending hearing* in this committee on April 12th, 2023.

SCR 21 (Archuleta, 2023) urges the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) to prioritize renewable, clean hydrogen for California, focus its efforts in communities with the largest pollution burden, and prioritize the hardest-to-abate sectors with the largest emissions profiles, among other items. Status: on Senate Floor after passage in the Senate Committee on Environmental Quality on March 15, 2023.

6) *Prior Legislation.*

SB 733 (Hueso, 2022), largely similar to the contents in this bill, required the CPUC to consider establishing procurement goals for "renewable hydrogen," as defined, for gas utilities and transporters, as specified. Status: Died in the Assembly Committee on Appropriations.

SB 1075 (Skinner) requires CARB and the CEC to analyze options for using hydrogen as part of decarbonization strategies. Previous versions of the bill included a definition for "renewable hydrogen" that was removed prior to passage, but was similar to the definition provided in this bill. Status: Chapter 363, Statutes of 2022.

AB 157 (Committee on Budget) defines "clean hydrogen" as hydrogen produced from eligible renewable energy resources, as defined within the Renewables Portfolio Standard (RPS) Program, and otherwise consistent with the federal standard set for carbon intensity of clean hydrogen production, or as that federal standard is revised or supplemented by CARB. Status: Chapter 570, Statutes of 2022.

SB 18 (Skinner, 2021) would have required CARB, CPUC and the CEC to incorporate green electrolytic hydrogen into various decarbonization strategies, and would have required CARB to analyze and provide recommendations regarding potential uses of hydrogen to reduce economy-wide emissions. Status: Held in the Assembly Committee on Appropriations.

SB 697 (Hueso, 2021) would have required CARB to establish a Green Hydrogen Credit Program to provide industrial facilities that produce green hydrogen with an additional Cap-and-Trade GHG allowance of 10 tons for every metric ton of green hydrogen produced during a compliance period. Status: Held in the Senate Committee on Appropriations.

SB 1122 (Skinner, 2020) would have required CARB to incorporate planning and recommendations for green electrolytic hydrogen into the scoping plan. The bill contained provisions substantially similar to some of those contained in this bill. Status: Died in the Senate Committee on Energy, Utilities, and Communications.

SB 1369 (Skinner) established a definition of green electrolytic hydrogen, required the CEC and CPUC to incorporate green electrolytic hydrogen as a resource that may be considered for procurement to reach state clean energy goals, and required the CPUC, CEC, and CARB to consider green electrolytic hydrogen an eligible form of energy storage. Status: Chapter 567, Statutes of 2018.

SB 1440 (Hueso) requires the CPUC, in consultation with CARB, to consider adopting specific biomethane procurement targets or goals for each corporation, as specified. This bill requires the CPUC, if the CPUC adopts those targets or goals, to take certain actions in regards to the development of the targets or goals and the procurement of the biomethane to meet those targets or goals Status: Chapter 739, Statutes of 2018.

AB 3187 (Grayson) requires the CPUC open a proceeding not later than July 1, 2019 to consider options to promote the in-state production and distribution of biomethane. Status: Chapter 598, Statutes of 2018.

SB 433 (Mendoza, 2017) would have authorized the CPUC to allow a gas corporation to procure zero-carbon hydrogen and recover through rates the reasonable cost of pipeline infrastructure developed to transport the hydrogen to end users. Status: Died in the Assembly Committee on Utilities and Energy.

SB 840 (Committee on Budget and Fiscal Review) required the CPUC to reevaluate its requirements and standards for biomethane to be injected into common carrier pipelines. Status: Chapter 341, Statutes of 2016.

AB 1900 (Gatto) directed the CPUC to identify landfill gas constituents, develop testing protocols for landfill gas injected into common carrier pipelines, adopt standards for biomethane to ensure pipeline safety and integrity, and adopt rules to ensure open access to the gas pipeline system. Status: Chapter 602, Statutes of 2012.

7) *Double Referral.* This bill is double-referred; upon passage in this Committee, this bill will be referred to the Assembly Committee on Natural Resources.

REGISTERED SUPPORT / OPPOSITION:

Support

Bioenergy Association of California
California Hydrogen Business Council
California State Pipe Trades Council
Coalition for Renewable Natural Gas
Electrochaea Corporation
Los Angeles County Sanitation Districts

Rincon Band of Luiseno Indians
Sempra Energy and its Affiliates: San Diego Gas & Electric Company and Southern California Gas Company – *sponsor*

Oppose

350 Bay Area Action
Agricultural Energy Consumers Association
Air Products and Chemicals, INC.
Asian Pacific Environmental Network
California Cotton Ginners and Growers Association
California Environmental Voters
California Fresh Fruit Association
California Manufactures & Technology Association
California Tomato Growers Association
Center for Biological Diversity
Climate Center; the
Communities for A Better Environment
Earthjustice
Far West Equipment Dealers Association
Leadership Council for Justice and Accountability
Nisei Farmers League
Sierra Club California
Western Agricultural Processors Association

Oppose Unless Amended

The Utility Reform Network (TURN)

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