Don Gilstrap
Manager, Fuels Regulations

October 15, 2024

Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Sahota:

Re: October 2024 15-Day LCFS Proposal

Chevron appreciates the opportunity to review and comment on the subject Low Carbon Fuel Standard rulemaking proposal.

Chevron is a major refiner and marketer of petroleum products and renewable fuels in the state of California and a regulated party under the Low Carbon Fuel Standard (LCFS). Chevron is also an international producer of lower carbon intensity fuels with a global integrated procurement, distribution and logistics network and 11 biorefineries in the U.S. and Europe.

Key Messages

- The proposed sustainability guardrails are unnecessary and pose a threat to supply reliability for renewable fuels.
- The proposed feedstock cap should explicitly exclude emerging cover crops which have a different emissions and land use profile than primary crops.
- Cutting off crediting for fossil-based hydrogen, penalizing it with a greater obligation, and requiring 80 vol% renewable content is punitive at a time when the industry is facing serious economic headwinds. This will deter investment in hydrogen refueling and carbon capture and sequestration projects as well as renewable hydrogen production.
- Reversing crediting for avoided methane runs counter to the goals of the LCFS and could cause backsliding.
- HRI continues to have limitations with the cap on HD capacity as well as the recording and recordkeeping requirements which add complexity.

Sustainability Guardrails

While we still oppose the introduction of sustainability criteria and believe they should be withdrawn, we want to emphasize that the most challenging and potentially disruptive proposal is the 2026 implementation date. Both U.S. and Canada planted crops have received approval from the US EPA under the aggregate compliance with renewable biomass requirement (80.1454(g)[1] and 80.1457[2]) for the US Renewable Fuel Standard. Canada's Clean Fuel Regulation (CFR) also provides an exemption to its crop feedstock rules for the U.S. and

[1] https://www.ecfr.gov/current/title-40/part-80/section-80.1454#p-80.1454(g)

[2] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-80/subpart-M/section-80.1457

Canada, based on U.S. RFS aggregate compliance (section 53[3]). This means that most crop-based renewable fuels consumed in North America are not mapped and tracked back to farm fields but are monitored in aggregate for any potential sustainability concerns. The only crop-based renewable fuels that are traced back to farm fields are those from foreign sources which are subject to the RFS recordkeeping (80.1454(d)(4)[4]) and reporting requirements (e.g. RFS0801 report[5]). It will be prohibitively challenging to map out every single farm that might supply fuel to California with less than 30 months to do so. We believe that this entire section should be removed or at least exempt U.S. and Canada crops, as they are under other North American programs. As written, the proposal will be disruptive for the California fuel market, particularly for ethanol. With the number of farms, feedstock aggregators, distributors, fuel producers, and fuel suppliers involved, there may be significant volumes of product that are blocked from entering the California market because of these requirements.

One of CARB's stated goals at the start of this rulemaking was to better align with federal policy. These sustainability guardrails not only depart from federal policy, but they are a duplicative burden to the feedstock and fuel supply chains for renewable fuels, without any added certainty around sustainability. As a major producer of renewable fuels, we are concerned about the impact on feedstock availability and the administrative burden caused by this proposal. As a fuel supplier in California, we are more concerned about the impact on supply reliability for both biomass-based diesel and ethanol. Given that nearly all gasoline in California contains 10% ethanol, any impact on supply reliability can have a significant impact on gasoline supplies.

At a time when fuel prices are under significant scrutiny and demand in California frequently outstrips supply, regulators should be careful about adding new measures that restrict supply. In addition to assessing the economic impact of the accelerated compliance schedule, has CARB evaluated the economic impact of the reduced supply these measures may cause? Without clear evidence that there is a problem to solve, such measures can do more harm than good. We urge CARB to withdraw or defer these new requirements to allow for, at minimum, a more reasonable timeline for implementation.

Arbitrary Restrictions on Specific Feedstocks

We continue to believe the cap on certain biofuel feedstocks is unnecessary and arbitrary. No scientific rationale has been provided and the fuels subject to the cap will naturally be phased out of the program by the declining carbon intensity targets.

As the affected feedstock list is updated to add sunflower oil, CARB should also ensure that no alternative feedstocks are inadvertently included. As we mentioned in previous comments, winter canola is an emerging feedstock with a materially different emissions and land use profile that should not be covered by the 20 percent cap. We recommend adding the following definition to § 95481(a):

> "Primary-Crop Canola" means canola that is the crop produced during that geographical area's main growing season. Primary-crop canola does not include canola that is grown

[3] https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

[4] https://www.ecfr.gov/current/title-40/part-80/section-80.1454#p-80.1454(d)(4)

[5] [5] List of Quarterly and Annual Reports for Renewable Fuel Standard - Compliance Year 2024 | US EPA

as a second crop or as a cover crop.

The term “Primary-Crop Canola” should then be incorporated into § 95482(i) as follows:

> Biomass-based diesel produced from soybean oil and primary-crop canola oil is eligible for LCFS credits for up to twenty percent combined of total biomass-based diesel annual production reporting, by company. Any reported quantities of biomass-based diesel produced from soybean oil and primary-crop canola oil in excess of twenty percent on a company-wide basis will be assigned a carbon intensity equivalent to the carbon intensity benchmark shown in Table 2 in Section 95484(e) for the applicable data reporting year, or the certified carbon intensity for the associated fuel pathway – whichever is greater. For companies with biomass-based diesel pathways certified prior to the effective date of the regulation and for which the percentage of biomass-based diesel produced from soybean oil and primary-crop canola oil was greater than 20 percent of combined reported biodiesel and renewable diesel quantities for 2023 LCFS reporting, this provision takes effect beginning January 1, 2028.

Table 6 should be updated to indicate that the land use change value listed applies to Primary Crop Canola Biomass-based Diesel.

The clarification that the feedstock cap will apply to Production, Production for Import, and Import transactions reported under the LCFS is an improvement. CARB should add Export transactions to that list to ensure that any production that enters and then leaves the state is not included.

Renewable Hydrogen Mandate

We object to the proposed language added to 95482(h) requiring that 80 percent of hydrogen dispensed as a vehicle fuel be renewable by January 1, 2030. This is the first volumetric mandate ever proposed under the LCFS, which runs counter to the design and intent of the program. Carbon intensity scores and annual benchmarks are the proper mechanisms to encourage a transition to lower-carbon solutions. An arbitrary volumetric requirement is inappropriate.

If we look at the ULSD market in California, baseline CI targets successfully drove the volumetric blending of biomass-based diesel without creating a market distortion or significant supply disruptions. The CI-based incentives drove investment in supply which then drove its end-adoption. The same is true for RNG displacing fossil-CNG and can also be true for hydrogen. No other fuel, including electricity, is held to a volumetric mandate which artificially penalizes hydrogen rather than letting it compete.

Volumetric targets are arbitrary and can have unintended consequences. In this case, the 80 percent requirement has a real chance of inhibiting investment in hydrogen fueling infrastructure. If there is uncertainty that enough renewable hydrogen will be available, why would fuel suppliers choose to invest their capital in the infrastructure to dispense it? If refueling infrastructure is threatened, why would producers invest in renewable hydrogen? If hydrogen supply is unavailable, why would end consumers purchase a fuel cell vehicle? The industry is facing a precarious situation with numerous supply and infrastructure shortages frustrating end consumers[6].

[6] Class action suit highlights inconvenience of hydrogen fuel cell cars - Los Angeles Times (latimes.com)

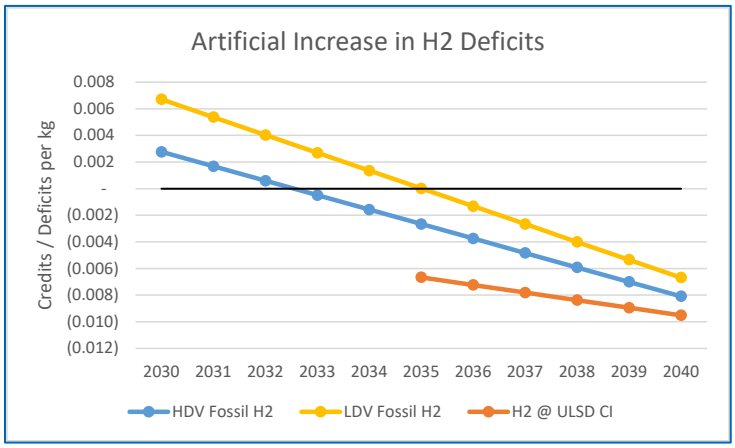
Over 95% of US production of hydrogen is produced from steam methane reforming of natural gas.[7] While new renewable hydrogen technologies have promise, it will take considerable time to develop these commercially on a large scale. Construction of large-scale facilities takes, at minimum, a 10-year cycle time for full capital project execution from final investment decision. Given that there are virtually no large-scale projects through final investment decision and permitting in California today, 2030 is far too early to implement an 80% renewable hydrogen requirement. In addition, the 80% renewable hydrogen requirement does not include CCUS-enabled hydrogen as a solution.

Further, the proposed language provides no procedures for measuring or enforcing this mandate. Is the 80 percent mandate measured company-wide or by facility? Is it an annual requirement? What happens if a company fails to meet the 80 percent requirement? These are not details that can be handled by guidance documents. Absent enforceable regulatory language, the proposed mandate only serves to add uncertainty for potential investors.

Fossil Hydrogen

Despite the five-year delay in its effective date, the cutoff of crediting for fossil-based hydrogen is still inappropriate. CARB has highlighted carbon capture and sequestration as a critical element of its Scoping Plan and there is potential for investment in CCUS-enabled hydrogen for California. If the LCFS will not reward such innovation, these investments will be discouraged.

Most problematic is the proposal to substitute the ULSD carbon intensity from Table 7-1 and an EER of 1.0 for hydrogen from fossil gas. There is no scientific basis for this. Most EER-adjusted pathways for fossil-derived H2 are > 40 gCO2/MJ below ULSD today. This not only disallows crediting but adds a penalty for fueling hydrogen fuel cell vehicles, inhibiting meaningful progress. Without this change, traditional hydrogen will be a deficit-generating fuel by 2035 which will drive producers to lower their CI. Substituting the ULSD CI and EER artificially more than doubles those deficits.



Hydrogen Refueling Infrastructure Crediting

The modifications to the hydrogen refueling infrastructure (HRI) crediting program as part of the 15-day package still do not address the concerns raised to incentivize hydrogen infrastructure development. According to CARB's AB8 reporting, the state is consistently under-performing on hydrogen infrastructure growth due to the high costs and numerous challenges associated with

[7] USDOE_FE_Hydrogen_Strategy_July2020.pdf (energy.gov)

building out hydrogen infrastructure and its value chain[8].

While we appreciate CARB effectively renewing the LMD-HRI program, there are still problems with the design of both programs including: requiring 80 vol% renewable hydrogen (as noted above), requiring cost and revenue data, limiting HD-HRI crediting capacities, and requiring that HD-HRI stations receive capital funding from a government-run grant program.

Since these restrictions limit the overall program benefits relative to the complexity of compliance, we will continue to see weak participation in the HRI program. These short-sighted restrictions do nothing to further the industry and will continue to leave consumers frustrated by lack of supply. Private investment is needed to drive technological innovations that bring the cost of hydrogen equipment down and allow the value chain to optimize. As hydrogen station infrastructure development has stalled, so too have fuel cell vehicle sales in the state[9].

Biogas Avoided Methane Crediting and Delivery Requirements

Chevron objects to the changes to avoided methane crediting and imposed delivery requirements. According to the EPA, anaerobic digestion provides a demonstrated, significant reduction in greenhouse gas emissions that would otherwise be released to the atmosphere and is the best manure management practice available to mitigate methane[10]. Limiting incentives for biogas and renewable natural gas producers is inconsistent with the Subnational Methane Action Coalition's statement of purpose, the 2021 Global Methane Pledge, and threatens the additional 2.4 MMTCO2e reductions needed per SB 1383 and California's Greenhouse Gas and Short-Lived Climate Pollutant Policy framework[11].

The timeline for avoided methane crediting is troublesome, as reviews by CARB staff for Tier 2 pathways have been extensively delayed beyond the 6 months estimated in the regulation. By restricting the avoided methane crediting period to the arbitrary timeline of the "effective date of the regulation," developers operating between the gap years of 2025 and 2030 will incur losses, discouraging investment.

The target of 132,000 Class 3-8 ZEVs or NZEVs is arbitrary and does not justify advancement of delivery requirements by 4 years. The ZEV or NZEVs target does not create the certainty of demand for RNG placement. Altogether, any delivery requirements are simply arbitrary —with no additional environmental benefit or grounding in the physical gas system. This change has the potential to deter growth and cause backsliding.

Automatic Acceleration Mechanism

The updates to the Automatic Acceleration Mechanism language are confusing and unnecessary. An annual review of the credit bank is sufficient and provides ample notice for regulated parties when the AAM is triggered. Further, it is unclear how the updated language in 95484(b) interacts with the original language in 95484(c). 95484(c)(2) states that "an updated benchmark schedule . . . will take effect January 1 of the calendar year after the Automatic Acceleration Mechanism was triggered." Does this mean that, if CARB announces that the AAM has been triggered on November 15, 2030, that a revised schedule would be posted on May 15, 2031, that is retroactive to January 1, 2031? These revisions also make it possible for the AAM to be triggered two years in a row, which was not the intent in the original proposal. This serves

[8] ww2.arb.ca.gov/sites/default/files/2023-12/AB-8-Report-2023-FINAL-R.pdf
[9] Class action suit highlights inconvenience of hydrogen fuel cell cars - Los Angeles Times (latimes.com)
[10] Practices to Reduce Methane Emissions from Livestock Manure Management | US EPA
[11] Dairy Sector Workshop Presentation (ca.gov)

only to add new uncertainty to the program and greater administrative burden for CARB staff. CARB should revert to the original language.

Validation & Verification

CARB should reconsider the site visit requirements for Quarterly Fuel Transaction Report verifications. This language insists that a site visit must occur at the central records location. Given that accounting records, spreadsheets, and nearly all product transfer documents are stored and transmitted electronically, often in cloud servers, there is no clear definition for the term “central records location.” It is costly and time-intensive to require the limited number of approved verifiers to travel to physical sites to review electronic records. Site visits should be limited to situations where a review of physical operations is warranted. All other engagements can be better handled virtually to save time and resources.

Thank you for the opportunity to comment on these matters. If you have any questions regarding our comments, please contact me at (925) 842-8903 or DGilstrap@chevron.com.

Sincerely,