Supplemental Workshop Frequently Asked Questions Document

December 2022

Overview

On November 9, 2022, CARB hosted a public workshop to provide input on potential changes to the Low Carbon Fuel Standard (LCFS). The workshop focused on introducing the California Transportation Supply (CATS) model and preliminary scenario design concepts that staff developed for modeling future LCFS targets.

Staff's presentation and other materials related to the workshop are posted on the LCFS Meetings and Workshops webpage. As a complement to these materials presented during the workshop, staff is including this Supplemental Frequently Asked Questions (FAQ) document to further clarify the workshop materials before the feedback period ends, which has been extended to December 21, 2022.

This document is organized by topic and is based on questions staff received during or after the workshop.

Frequently Asked Questions

CATS Model

Q: When will the CATS model be posted?
A: The CATS model is now posted on the LCFS Meetings and Workshops webpage.

Q: Is the deadline for public comments and for providing requests for alternatives on the SRIA the same?
A: Staff is extending the deadline to receive feedback, including SRIA alternatives, to December 21, 2022.

Q: What carbon intensities (CI) are assumed in the model for particular fuel pathways?
A: CIs assumed in the model are documented in the "Fuel Production" tab of the CATS Summary Inputs spreadsheet, which is posted on the LCFS Meetings and Workshops webpage.

Q: Can new feedstock-fuel combinations be added to the model?
A: Yes. Refer to slide 19 of the November 9 workshop presentation for the information staff requires when defining additional feedstock-fuel combinations in the model.
Q: What are the percentage CI reductions for the Alternatives presented at the workshop?
A: The percentage CI reductions are summarized below:

Year	Alt A Percent Reduction	Alt B Percent Reduction	Alt C Percent Reduction
2022	10.0%	10.0%	10.0%
2023	11.3%	11.3%	11.3%
2024	12.5%	12.5%	12.5%
2025	14.6%	15.4%	16.3%
2026	16.7%	18.3%	20.0%
2027	18.8%	21.3%	23.8%
2028	20.8%	24.2%	27.5%
2029	22.9%	27.1%	31.3%
2030	25.0%	30.0%	35.0%
2031	27.1%	32.7%	37.9%
2032	29.5%	35.5%	40.9%
2033	32.3%	38.6%	44.0%
2034	35.3%	41.9%	47.3%
2035	38.7%	45.3%	50.6%
2036	42.4%	48.9%	54.1%
2037	46.4%	52.7%	57.6%
2038	50.8%	56.7%	61.3%
2039	55.4%	60.9%	65.1%
2040	60.4%	65.3%	69.0%
2041	65.7%	69.9%	73.0%
2042	71.3%	74.7%	77.1%
2043	77.3%	79.6%	81.3%
2044	83.5%	84.8%	85.6%
2045	90.0%	90.0%	90.0%

Q: What are the electricity grid CI values based upon?
A: The electricity CI values in the model start with the recently proposed 2022 annual update to the California average grid CI value, 76.37 g/MJ[1]. Future average grid CI assumptions are based upon values used in the draft 2022 Scoping Plan and are published in the CATS Technical Documentation on page 13.

Q: Does the CATS model assume any changes to Energy Economy Ratios (EER)?

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[1] Proposed annual update to Lookup Table Pathways (2022): https://www.arb.ca.gov/fuels/lcfs/fuelpathways/comments/tier2/2022_elec_update.pdf?_ga=2.174538535.401216739.1669653999-878175293.1561566295

A: The CATS model can reflect different EERs over time if included as an input. The preliminary scenarios presented at the November 9, 2022, workshop make no change to the existing EERs listed in Table 5 of the LCFS regulation. Staff encourages feedback with regard to particular EERs that may warrant updates, or new EER categories.

Q: Will the CATS model allow for modelling of higher level blends of E15 and E85?
A: As detailed in the CATS Technical Documentation, E85 is incorporated into the reference scenario. Blending minimums and maximums may be specified in the model by the user.

Q: Is CCS reflected in the model?
A: CCS is recognized in the LCFS program in several ways; as part of a fuel pathway in which it lowers the CI, or as part of an innovative crude or refinery investment project. Both options are available in the CATS model. For CCS applied to fuel pathway production processes, the user would need to define a new feedstock-fuel combination, including the CI of the fuel pathway and the cost of production. CCS attached to corn ethanol is currently defined in the model, but others could be added. Project-based crediting is covered in the "Petroleum projects" category. Credits from CCS applied to oil fields or refineries would be manually read into the model.

Q: Can you please explain how the assumptions of Renewable Fuel Standard credits (Renewable Identification Number, or RIN) and 45(Q) exogenous subsidies are impacting the economic optimization of ethanol in the model?
A: The price for ethanol that the model uses in the optimization equation is equivalent to the spot market price minus the D6 RIN value. The spot market ethanol price was assessed using 200 historic Ag Market News Reports from USDA. RIN prices were assessed using Argus data to estimate annual RIN value, assumed to be $1.13 per D6 RIN, as per the CATS Technical Documentation that was posted. Because RINs, once unbundled, have their own commodity market to establish pricing, it is assumed that the RIN price changes in response to other subsidies to ensure that ethanol can be blended at levels required to meet the RFS. As such, the RIN used accounts for the blender's tax credit. For ethanol with carbon capture and sequestration (CCS), provisions under 45(Q) of the Internal Revenue Service's tax code also apply, which provides between $60 and $85 per metric ton of CO2 captured. CO2 that is captured and used or captured and stored in oil and gas fields is eligible for $60 per metric ton. For modeling purposes, it was assumed that the majority of CO2 captured from ethanol would either be used or stored in oil and gas fields. This translates to a subsidy value of approximately $0.002 per MJ of ethanol produced with CCS. In addition to the RIN value, this provides a total subsidy of approximately $0.02 per MJ for ethanol.

Q: The ethanol conversion cost is being listed as $0.80 per bushel which equates to $2.32 per gallon. How is this derived? Does it include all production and transportation costs? It appears too high if it is only the actual plant conversion costs.
A: Historic data from two hundred USDA-MO Department of Ag Market News Reports were used. Report number NW-GR212 lists ethanol prices and corn prices for the same time period. Ethanol price, in $/gallon was regressed against corn price in $/bushel. This resulted in a fixed cost of $0.0595 per gallon (intercept), or $0.17 per bushel, and a conversion factor of 0.3465 bushels per gallon. Transportation costs were assumed to be 20 cents per gallon, or approximately $0.58 per bushel, translating to $0.75 total per bushel. This is detailed in the technical documentation that was posted.

Biomethane

Q: Is CARB proposing to phase out all biomethane in the LCFS program?
A: No, CARB is not proposing to phase out all biomethane in the LCFS program. However, staff is looking to align the treatment of biomethane under the LCFS program to align with larger climate and energy policies to reflect Executive Orders, Statutes, Regulations, and the 2022 Scoping Plan. See below for proposed nuances on changes to the treatment of biomethane under the LCFS program.

Q: Why is CARB considering a phaseout of avoided methane emissions by 2040?
A: This concept is focused on supporting California's achievement of the 2030 methane reduction SB 1383 statutory targets, which necessitate the deployment of methane reduction strategies this decade.[2] Staff is also following the high-level signals in the Final 2022 Scoping Plan, which shows both an increase in supply of biomethane this decade and then a general shift in the end-use of biomethane to sectors outside of transportation over the coming decades. Figures H-3 and H-4 of Appendix H[3] of the Final 2022 Scoping Plan depict the biomethane supply and end-use demand from sources in California in both 2030 and 2045.

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[2] CARB, 2022. Analysis of progress toward achieving the 2030 dairy and livestock sector methane emissions target. https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf

[3] Appendix H: https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-h-ab-32-ghg-inventory-sector-modeling.pdf

Figure H-3. Biomethane Supply from Sources in California

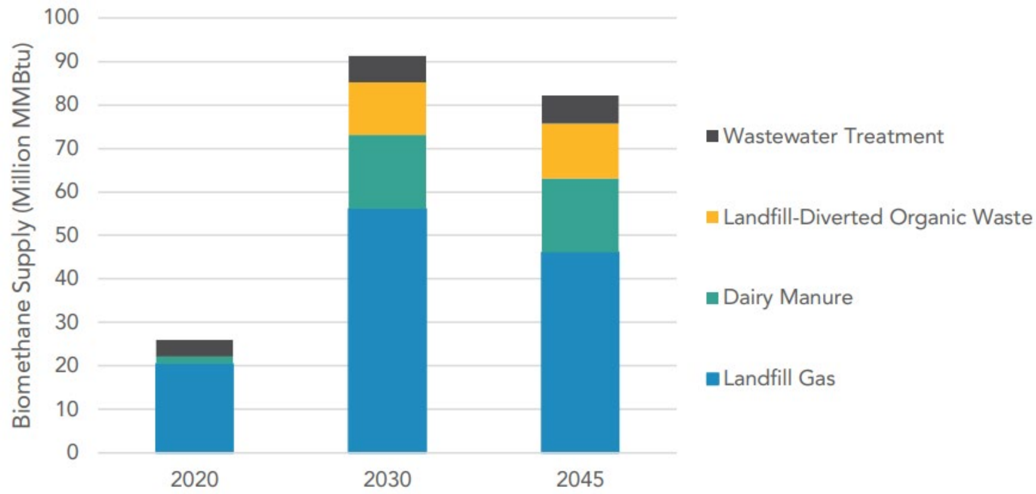
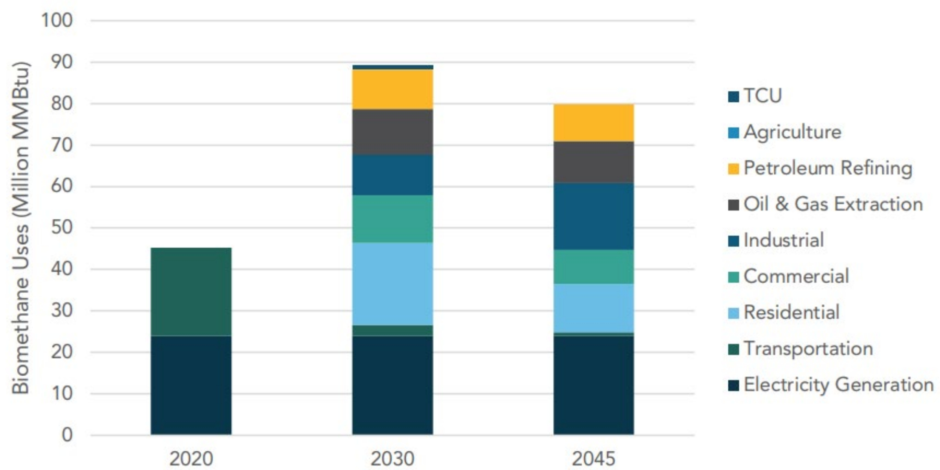


Figure H-4. Biomethane Use in California by Sector



Staff are mindful of the importance of providing an appropriate transition time to ensure alternative options are available for use of biomethane in the long-term. CARB also seeks to encourage methane reduction projects now, while also providing investment certainty and avoiding stranded assets over the coming decades.

With these goals in mind, the preliminary modeling scenarios include several considerations. One mechanism is to phase out avoided methane crediting from LCFS pathways, beginning in 2030 and completing by 2040. At this time, avoided methane crediting is certified for 10-year crediting periods, with no end-date specified. The phaseout concept in Alternatives A and B encourages rapid development of methane reduction projects prior to 2030.

Q: Can you describe the avoided methane phaseout concept that is included in Alternatives A and B?
A: In Alternatives A and B, fuel pathways with avoided methane would be approved for new 10-year crediting periods until 2030. For example, if an entity were to install a digester and apply for LCFS crediting in 2023, they would receive the full 10-year crediting period for avoided methane; and likewise, for other projects certified before 2030. Staff is proposing to keep that same treatment for projects that apply until 2030, with the intent of encouraging development of methane-reducing projects in the near-term to help achieve the SB 1383 methane reduction target. This would result in a phaseout of fuel pathways with avoided methane by 2040, at the end of the last 10-year crediting period.

Q: Why is CARB considering a change to the biomethane book-and-claim (B&C) provisions for certain projects?
A: CARB is considering aligning the deliverability requirements of biomethane with other fuels. Currently, the LCFS regulation allows for indirect accounting of biomethane when injected into the North American natural gas pipeline without a requirement to demonstrate a deliverability path to California, which differs from treatment of indirect accounting of low-CI electricity. We welcome feedback on how to improve consistency with biomethane deliverability requirements, the mechanisms to ensure compliance of deliverability requirements, and the regulatory timing for changing the current book-and-claim provisions.

Q: Can you describe the biomethane B&C changes that are included in Alternatives A and B?
A: Alternatives A and B harmonize the deliverability requirements between low-CI electricity and biomethane by requiring that biomethane injected into the pipeline for use in California come from projects in regions that currently supply the majority of fossil gas to California. As depicted in Figure H-3, staff expects that the ramp up of biomethane projects to achieve the SB 1383 targets can replace much of the biomethane volume that would no longer be eligible for B&C under this concept. In addition, while not discussed at the workshop, one implementation option for this change of B&C accounting would be to only apply this B&C change to new fuel pathways submitted after the start of 2025, which means pathways for projects outside of the western region approved prior to 2025 would retain B&C for their 10-year crediting periods. Staff is seeking feedback on this date in particular.

In addition, starting 2030, staff proposed that landfill gas would only be eligible for book-and-claim if used for hydrogen production. Staff seeks to strike the balance of supporting transportation fuel needs while following the trajectory in the 2022 Scoping Plan of achieving California's methane reduction targets and transitioning biomethane to non-transportation sectors. As Figure H-4 demonstrates, biomethane used as a transportation fuel will likely play a much smaller role in 2045 than it does today. However, given the need for renewable hydrogen supply to increase to meet hydrogen transportation fuel demand, biomethane could still be used to produce renewable hydrogen in the transportation sector, which would qualify for LCFS crediting.

Crop-based fuel limitations

Q: What feedstocks are subject to the conceptual cap included in Alternatives A and B?
A: For Alternatives A and B, staff included an upper limit on credits for diesel fuels derived from virgin oil feedstock, which would potentially include soybean oil, corn oil, canola oil, and white grease. For the purposes of CATS modeling, waste feedstocks were assumed to consist of tallow and yellow grease. This does not include ethanol used in the gasoline pool, since there is a natural upper limit with the current blend wall. Staff is interested in feedback on inclusion of these and other feedstocks.

Q: Corn oil is included on the list of virgin oils. Corn oil from the ethanol production process is a coproduct of the production process and is an inedible corn oil (ICO). Shouldn't ICO not be referenced as virgin oil?
A: For this first iteration of the model, CARB did not consider corn oil to fall under the waste oil category as it has market uses outside of biofuel production or disposal and can realize value from use in these other markets. Such alternative uses may include things such as animal feed. Staff welcomes feedback on this assumption to help inform future changes to the model.