RECIRCULATED DRAFT ENVIRONMENTAL IMPACT ANALYSIS

for the Proposed

Low Carbon Fuel Standard Regulation

California Air Resources Board

1001 I Street

Sacramento, California 95814

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LIST OF ABBREVIATIONS

AAM	Auto Acceleration Mechanism
AB	Assembly Bill
AJF	alternative jet fuel
BAAQMD	Bay Area Air Quality Management District
BEV	battery-electric vehicle
CalEEMod	California Emissions Estimator Model
CalGEM	California Department of Conservation Geologic Energy Management Division
CARB or Board	California Air Resources Board
CCR	California Code of Regulations
CCS	carbon capture and storage
CEQA	California Environmental Quality Act
CI	carbon intensity
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
DAC	direct air capture
EER	Energy Economy Ratio
EIA	environmental impact analysis
EIR	environmental impact report
EMFAC	California Emissions FACtor Model
EV	electric vehicle
FCI	Fast Charging Infrastructure

gCO_2e/MJ	grams of carbon dioxide equivalent per megajoule of fuel energy
GHG	greenhouse gas
GTAP	Global Trade Analysis Project
HRI	Hydrogen Refueling Infrastructure
ISOR	Initial Statement of Reasons
LCA	Life Cycle Analysis
LCFS	Low Carbon Fuel Standard
L-CNG	Liquefied Compressed Natural Gas
LD	light-duty
LNG	liquefied natural gas
LRT	LCFS Reporting Tool
LUC	Land use change
MHD	medium- and heavy-duty
$MTCO_2e$	metric tons of carbon dioxide equivalent
NAAQS	national ambient air quality standards
NO_X	oxides of nitrogen
PHEV	plug-in hybrid electric vehicle
PM	particulate matter
PM10	respirable particulate matter
PM2.5	fine particulate matter
PRC	Public Resources Code
Proposed Amendments	proposed regulatory amendments to the Low Carbon Fuel Standard
RNG	renewable natural gas

SB	Senate Bill
SIP	State Implementation Plan
TAC	toxic air contaminant
UCO	used cooking oil
U.S. EPA	U.S. Environmental Protection Agency
ZEV	zero-emission vehicle

1.0 Introduction and Background

A. Introduction

In January 2024, the California Air Resources Board (CARB) released for public review the Draft Environmental Impact Analysis for the Low Carbon Fuel Standard (LCFS) Regulation (Draft EIA), which assesses the potential environmental impacts of implementing the proposed regulatory amendments to the LCFS program (Proposed Amendments).

CARB circulated the Draft EIA for public review and comment for a period of 45 days that began on January 5, 2024, and ended on February 20, 2024. During the review period, written comments were received on the Draft EIA. CARB reviewed the comments to identify environmental topics and began preparation of responses to those comments. After the end of the Draft EIA public review period, CARB identified revisions to certain aspects of the Proposed Amendments that merit revisions to the project description. In particular, the project description has been updated through 15-day changes released on August 12, 2024, to: remove fossil jet fuel from the list of transportation fuels subject to the LCFS; modify the annual carbon intensity benchmarks for gasoline and fuels used as a substitute for gasoline, diesel fuel and fuels used as a substitute for diesel fuel, and fuels used as a substitute for fossil jet fuel; expand zero emission vehicle refueling infrastructure crediting opportunities; remove eligibility for hydrogen produced from fossil fuels beginning in 2031; modify crediting provisions for biomass-based diesel pathways; reduce the crediting periods for avoided methane emissions; provide an opportunity for automakers to generate base credits; and add further details to the sustainability certification proposal.[1] The project description has been updated here for clarity and consistency. Additional background information and analysis about whether dairy herd size expansion may be a reasonably foreseeable compliance response to the Proposed Amendments was also added in the project description. The changes are provided in Chapter 2.0, "Project Description," below. In addition, in response to public comment, the air quality and greenhouse gas (GHG) evaluations have been reassessed and expanded with additional information for clarity. Specifically, these sections have been updated with modeling outputs that reflect the Proposed Scenario in the 15-day Notice package released August 12, 2024, as well as additional granularity regarding the sources of particulate matter (PM) and oxides of nitrogen (NOx) emissions changes under the Proposed Amendments. This information matches the level of detail posted after the 45-day comment period on the Supplemental 2023 LCFS ISOR Documentation webpage.[2] The workbooks underlying these emission change graphics are also posted on the Supplemental Documentation webpage

[1] See California Air Resources Board, *Attachment A-1: Proposed 15-day Changes, Proposed Amendments to the Low Carbon Fuel Standard.* August 12, 2024. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/15day_atta-1.pdf

[2] California Air Resources Board. *Supplemental 2023 LCFS ISOR Documentation.* April 9, 2024. https://ww2.arb.ca.gov/resources/documents/supplemental-2023-lcfs-isor-documentation

incorporated with the 15-day Notice package.[3] These evaluations are provided in Chapter 3.0 below.

In accordance with Public Resources Code (PRC) Section 21092.1 and Title 14 California Code of Regulations (CCR) Section 15088.5, when "significant new information is added to an environmental impact report (EIR) after notice has been given pursuant to Section 21092" and the draft EIR has undergone public review, a lead agency must recirculate the environmental document for public review of the new information. For these purposes, "information" can include changes in the project's environmental setting as well as additional data or other information. Recirculation is not required unless the EIR is changed in a way that would deprive the public of the opportunity to comment on significant new information, including a new significant impact for which no feasible mitigation is available to fully mitigate the impact (thus resulting in a significant and unavoidable impact), a substantial increase in the severity of a disclosed significant environmental impact, development of a new feasible alternative or mitigation measures that would clearly lessen environmental impacts but that the project proponent declines to adopt, or the draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded (Title 14 CCR Section 15088.5[a]). Recirculation is not required when the new information added to the EIR merely clarifies or amplifies or makes insignificant modifications in an adequate EIR (Title 14 CCR Section 15088.5[b]).

Here, the revisions to the project description are based on additional changes to the Proposed Amendments as well as the inclusion of additional information provided in the air quality and GHG evaluations. These revisions and additional information have not shown any new, substantial environmental impacts, any substantial increases in the severity of an environmental impact, or any alternative or mitigation measure considerably different from those considered in the Draft EIA. Rather, the revisions and additional information have resulted in the addition of substantial new information compared to what was presented in the Draft EIA. Therefore, CARB has determined that recirculation of the project description and the air quality and GHG evaluations is warranted. In accordance with Title 14 of the California Code of Regulations, section 15088.5(f)(2), CARB will be accepting new comments on only the portions of the Draft EIA included in this recirculation. Comments previously submitted about the portions of the Draft EIA that have been revised and recirculated in this Recirculated Draft EIA do not require a further written response from CARB in the Final EIA. To receive a written response specifically regarding these revised portions of the EIA, commenters must timely submit new comments. All previously submitted comments on the Draft EIA that are not addressed with this recirculation, as well as any additional comments submitted pertaining to this recirculated information, will be responded to in the Response to Comments on the Draft

[3] California Air Resources Board. *Supplemental 2023 LCFS ISOR Documentation.* April 9, 2024. https://ww2.arb.ca.gov/resources/documents/supplemental-2023-lcfs-isor-documentation.

and Recirculated Environmental Impact Analysis for the proposed Low Carbon Fuel Standard Regulation.

2.0 Project Description

A. Introduction

CEQA requires agencies to evaluate the environmental impacts of a project, or the "whole of an action," when conducting CEQA analyses (see CEQA Guidelines Section 15378). The CEQA "project" for purposes of this Recirculated Draft EIA includes the Proposed Amendments. While the Proposed Amendments constitute the "project" for CEQA purposes (CEQA Guidelines Section 15378), this document also uses the term "project" to refer to reasonably foreseeable activities, such as construction of fuel facilities that might be undertaken in response to the Proposed Amendments.

This chapter provides a background summary of the existing LCFS regulation and summarizes the Proposed Amendments, including establishing appropriate average carbon intensity (CI) requirements through 2045 and other changes, updates, and improvements to existing provisions, models, and procedures. Additional details about the amendments are available in the Initial Statement of Reasons (ISOR)[4] and in the 15-day Notice package released August 12, 2024. The third part of this chapter describes an illustrative, reasonably foreseeable compliance response scenario resulting from these Proposed Amendments. This information provides a basis for the subsequent discussion of the reasonably foreseeable environmental effects of the Proposed Amendments in Chapter 3.0, as required by CEQA (PRC Section 21159).

For a detailed description of how the Proposed Amendments are different from the current regulation as amended in 2018 and 2019, see Chapter II of the ISOR and the 15-day Notice package released August 12, 2024. For a description of the regulatory background driving the need for the Proposed Amendments, see Chapter III of the ISOR, Appendix D to the ISOR, and section D of this chapter.

B. Project Objectives

The current LCFS regulation is designed to reduce the CI of fuels used in California's transportation sector by requiring annual reductions in the volume-weighted average CI of transportation fuels used in the state. While fuels with higher CIs can and will be used, the LCFS regulation creates financial incentives for the development and use of fuels with lower CIs. Fuel reporting entities, such as fuel producers or distributors, must meet the annual CI standard through mechanisms such as producing lower-carbon fuels, buying such fuel from producers to sell on the market, purchasing credits generated by others, using banked credits generated in previous years, or a combination of these strategies. The LCFS regulation establishes three sets of

[4] California Air Resources Board, *Staff Report: Initial Statement of Reasons: Public Hearing to Consider the Proposed Amendments to the Low Carbon Fuel Standard.* December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

performance standards that determine the treatment of each fuel used in California: 1) a standard for gasoline and alternative fuels that substitute for gasoline, 2) a standard for diesel fuel and its substitutes, and 3) a standard for fuels used as a substitute for fossil jet fuel. These standards were established to achieve an average 20% reduction in the CI of the statewide mix of transportation fuels by 2030 and all subsequent years, as compared to 2010, in line with California's 2030 GHG target to reduce GHG emissions by 40% from the 1990 levels as enacted through Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016).

LCFS standards are expressed in terms of the CI of gasoline and diesel fuel and their substitutes, measured in grams of carbon dioxide equivalent per megajoule of fuel energy (gCO_2e/MJ). Each step in the life cycle of the fuel, including production, transportation, distribution, and consumption, is modeled by fuel pathway applicants and certified by CARB to determine the CI of the fuel.[5] In addition to the direct life cycle emissions, indirect land use change emissions are calculated on a fuel-by-fuel basis and included in their total CI.[6] The various factors used to determine a fuel's CI value are referred to as the fuel pathway.

The current LCFS regulation applies to most types of transportation fuels used in California,[7] including:

1. California reformulated gasoline,
2. California ultra-low sulfur diesel fuel,
3. Compressed or liquefied natural gas,
4. Electricity,
5. Compressed or liquefied hydrogen,
6. Any fuel blend containing hydrogen,
7. Any fuel blend containing greater than 10% ethanol by volume,
8. Any fuel blend containing biomass-based diesel,
9. Neat denatured ethanol,
10. Neat biomass-based diesel,
11. Alternative jet fuel (AJF), and

[5] California Air Resources Board, *CA-GREET3.0 Model and calculators*. (Accessed August 14, 2024). https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation
[6] California Air Resources Board, *LCFS Land Use Change Assessment.* (Accessed August 14, 2024). https://ww2.arb.ca.gov/resources/documents/lcfs-land-use-change-assessment
[7] As defined under Cal. Code Regs., tit. 17, § 95482(a).

12. Propane and any other liquid or non-liquid fuel not otherwise exempted from the regulation.

The regulatory requirements initially apply to California producers and importers of fuels, although the compliance obligations can be transferred to downstream owners of the fuel. Providers of certain low-CI fuels (i.e., electricity, hydrogen, and biogas fuels) are not subject to the LCFS unless they opt into the program to generate credits from the supply of the fuel to the California market.

Table 1 provides the CI reductions required under the current LCFS regulation. As indicated, CI is required to be reduced through a series of annual targets to reach the 2030 goal of a 20% reduction in the average CI of fuels in California compared to 2010.

Table 1: Carbon Intensity Reduction Requirements through 2030[8] (Relative to 2010)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Required CI Reduction (%)	6.25	7.5	8.75	10	11.2	12.5	13.75	15	16.25	17.5	18.7	20

Under the LCFS regulation, a fuel reporting entity is a California fuel producer, provider, or importer that must meet the annual compliance requirements of the LCFS regulation. Supplying a fuel with a CI that is below the standard in a given year generates credits; conversely, supplying a fuel with a CI above the standard generates deficits. Credits and deficits are determined on a quarterly basis. For a given annual compliance period, a fuel reporting entity's compliance obligation is determined by adding up all the quarterly deficits assessed to that party. A regulated party's annual compliance obligation is met when the regulated party demonstrates, via its annual report, that it possessed and has retired a number of credits that is equal to its compliance obligation. Credits are "tradeable." That is, a regulated party can purchase them from other program participants. Credits earned from CI reductions from diesel and diesel substitutes, the alternative fuels that substitute diesel, may be used to offset deficits generated from the supply of gasoline and gasoline substitutes, and vice versa. The credits are also "bankable" (i.e., surrendering credits that the fuel reporting entity already has accumulated in prior compliance periods is permissible). A fuel reporting entity may also, under certain circumstances, pass the LCFS compliance obligation for that fuel to the buyer of the fuel as part of the sales transaction.

[8] California Air Resources Board, *Unofficial electronic version of the Low Carbon Fuel Standard Regulation*. 2020. *https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf*

A fuel pool is the full collection of fuels that a fuel reporting entity produces in California for use in the State, imports into California for use in the State, and/or buys in California for use in the State. A fuel reporting entity's fuel pool may include gasoline, diesel, blendstocks, and substitutes. Blendstocks are components that are either used alone or are blended with other component(s) (e.g., ethanol) to produce a finished fuel. A blendstock generally has one or more fuel pathways. A substitute is a fuel that is used in place of the standard fuel for that type of application (e.g., diesel is typically used in heavy-duty vehicle applications, so a fuel substitute for that diesel might be compressed natural gas [CNG] or liquefied natural gas [LNG]).

The LCFS regulation designates a number of lower-carbon fuels as "opt-in" for which participation in the program is optional. These include:

1. Electricity,
2. Biogas CNG,
3. Biogas LNG,
4. Biogas liquefied compressed natural gas (L-CNG),
5. AJF, and
6. Renewable propane.

Providers of these fuels have no obligation to participate in the LCFS program. However, as previously noted, the LCFS regulation provides the opportunity to generate credits for these fuels, and credits could be sold to or surrendered by fuel reporting entities who need the credits to meet compliance obligations. Parties may opt into the LCFS program to become fuel reporting entities for these fuels. The provider of an opt-in fuel participates by registering as a fuel reporting entity and agreeing to be bound by LCFS compliance, recordkeeping, reporting, and other requirements.

The LCFS regulation also provides fuel reporting entities options to directly reduce the CI of conventional fuels and generate credits. The innovative crude provision, which provides credits for crude oil that has been produced or transported using innovative methods and delivered to California refineries for processing, promotes the development and implementation of innovative crude oil production methods that reduce greenhouse gas (GHG) emissions. Allowable methods are carbon capture and storage (CCS), solar steam generation, solar and wind electrical power generation, and solar heat generation. The Low-Complexity/Low-Energy-Use Refinery provision provides credits to small refineries. To incentivize GHG reductions at refineries, the LCFS regulation also established the Renewable Hydrogen Refinery Credit Program and the Refinery Investment Credit Program.

The LCFS Reporting Tool (LRT) is an accounting system that records the credit or deficit "obligation" based on the type of fuel and business transactions. The LRT calculates the overall credit/deficit for the quarter based on the annual standard, fuel CI, volume, and Energy Economy Ratio (EER), if applicable. EERs are used to adjust credits associated with a vehicle's fuel efficiency. On an annual basis, fuel reporting entities are required to review these submittals and submit an annual report verifying the validity of the four quarterly reports. The results are used to determine compliance with LCFS targets for that given year. The LCFS regulation requires fuel reporting entities to use the LRT to report fuel and credit transactions subject to the LCFS regulation.

C. Objectives of the Proposed Amendments

There have been several major new climate statutes enacted and executive orders issued since the last major LCFS rulemaking in 2018. In 2022, Governor Gavin Newsom signed several climate bills, including Assembly Bill (AB) 1279 (Muratsuchi, Chapter 337, Statues of 2022),[9] SB 905 (Caballero, Chapter 359, Statutes of 2022),[10] and SB 1020 (Laird, Chapter 361, Statutes of 2022).[11] A particular focus on the transportation sector was established through Executive Order N-79-20,[12] which established a State goal that sales of all new passenger vehicles be zero emission by 2035 and that 100% of medium- and heavy-duty vehicles in the State be zero emission by 2045 for all operations where feasible and by 2035 for drayage trucks. The 2022 Scoping Plan for Achieving Carbon Neutrality (2022 Scoping Plan Update),[13] approved by the Board in December 2022, lays out a cost-effective and technologically feasible path to achieve these targets and achieve carbon neutrality by 2045. In order to implement the 2022 Scoping Plan Update, California needs to reduce emissions by driving down fossil fuel demand in transportation, transitioning to zero-emission technology wherever feasible, and increasing the supply of low-carbon alternative fuels as quickly as possible.

The primary objectives of the Proposed Amendments are:

1. Improve California's long-term ability to support the production and use of increasingly lower-CI transportation fuels and to improve the program's overall effectiveness;

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[9] AB 1279 requires an 85% reduction in anthropogenic GHG emissions below 1990 levels by 2045.
[10] SB 905 requires CARB to establish a program and adopt regulations related to the development of carbon capture, removal, and storage projects.
[11] SB 1020 includes new benchmarks of 90% clean electricity by 2035 and 95% by 2040 ahead of the 100% goal by 2045.
[12] State of California Executive Department, Executive Order N-79-20. September 23, 2020. https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf
[13] California Air Resources Board, *2022 Scoping Plan for Achieving Carbon Neutrality*. November 16, 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf

2. Update the annual carbon intensity benchmarks through 2030 and establish more stringent post-2030 benchmarks in alignment with the 2022 Scoping Plan;
3. Increase the flexibility of the program to adjust for potential future market over-performance by including a mechanism that would automatically accelerate the compliance targets under certain conditions;
4. Include a step-down in the near-term CI target to further support ambition;
5. Incentivize fuel production and refueling infrastructure buildout needed to meet California's long-term climate goals and reduce dependence on petroleum fuels, including opportunities to leverage federal funding for low-carbon hydrogen production and zero emission vehicle (ZEV) fueling, and support the transition of biomethane fuel pathways for combustion out of transportation;
6. Update standard values in the regulation, including emission factors, as well as life cycle assessment (LCA) modeling tools to use more detailed or recent data; and
7. Streamline implementation of the program.

D. Description of the Proposed Amendments to the Low Carbon Fuel Standard

1. Strengthen the Annual Carbon Intensity Benchmarks Pre- and Post-2030

The current LCFS targets a 20% reduction in average fuel CI by 2030 and maintains that target for all subsequent years. Staff is proposing to increase the stringency of the LCFS program by strengthening the annual CI benchmarks pre- and post-2030. Strengthening the CI benchmarks would result in faster decarbonization of the transportation fuel pool, which is needed for alignment with AB 1279 (carbon neutrality and an 85% reduction from a 1990 statewide GHG inventory by 2045) and the ambition called for in the 2022 Scoping Plan Update. The 2022 Scoping Plan Update lays out a path to achieve state goals and achieve carbon neutrality by 2045. There is an opportunity to strengthen the CI benchmarks because investment in low-carbon fuel production and adoption of electric vehicles (EVs) have outpaced projections, resulting in "overperformance" in the low-carbon fuels market relative to the current targets. Staff is proposing to strengthen the pre-2030 CI benchmarks and create post-2030 CI benchmarks to signal long-term support for LCFS, which will help signal a strong LCFS market for the more infrastructure-heavy investment needed (e.g., refinery conversions and CCS). Staff is proposing a 30% CI reduction target in 2030 and a 90% reduction target in 2045 to accelerate GHG reductions in transportation fuel to align with 2022

Scoping Plan Update direction. Scenarios modeled both in-house[14] by CARB and by external stakeholders[15] indicate that a reduction of 30% by 2030 and 90% by 2045 is achievable and necessary to decarbonize the transportation fuels sector and support the state's broader climate goals.

Table 2 provides the proposed CI reductions from 2024 through 2045 from a 2010 baseline. The proposed amendments will extend the LCFS targets to meet a 90% reduction in fuel CI from a 2010 baseline by 2045 while updating the 2030 reduction to 30% from 20%. CI reduction targets have historically been listed in comparison to 2010, the year before the first CI reductions began. This is distinct from the use of 2023 as the CEQA baseline for the purposes of the Proposed Amendments.

Table 2: Proposed Carbon Intensity Reduction Requirements from 2024 through 2046 (Relative to 2010)

Year	Proposed CI Reduction Target
2024	12.5%
2025	22.7%
2026	24.2%
2027	25.6%
2028	27.1%
2029	28.6%

[14] California Air Resources Board, *Low Carbon Fuel Standard 2023 Amendments: Standardized Regulatory Impact Assessment (SRIA)*. September 8, 2023. *https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf*

[15] ICF Resources LLC, *Analyzing Future Low Carbon Fuel Targets in California: Initial Results for Accelerated Decarbonization, Central Case*. Submitted to Auto-Acceleration Mechanism for the Low Carbon Fuel Standard Public Comment Docket. June 30, 2023. *https://ww2.arb.ca.gov/form/public-comments/submissions/4306*

Ro, J.W., Murphy, C.W., & Wang, Q., *Fuel Portfolio Scenario Modeling (FPSM) of 2030 and 2035 Low Carbon Fuel Standard Targets in California*. UC Davis ITS Research Report UC-ITS-RIMI-3L, Davis CA. DOI: 10.7922/G2S46Q8C. *https://escholarship.org/uc/item/6f2284rg*

Bushnell, J., Lade, G., Smith, A., Witcover, J. & Xiao, W., *Energy Institute at Haas WP 340: Forecasting Credit Supply Demand Balance for the Low-Carbon Fuel Standard Program*. August 2023. *https://haas.berkeley.edu/wp-content/uploads/WP340.pdf*

Year	Proposed CI Reduction Target
2030	30.0%
2031	34.5%
2032	39.0%
2033	43.5%
2034	48.0%
2035	52.5%
2036	57.0%
2037	61.5%
2038	66.0%
2039	70.5%
2040	75.0%
2041	78.0%
2042	81.0%
2043	84.0%
2044	87.0%
2045	90.0%
2046	90.0%

Additionally, the growth in credit generation in the past few years demonstrated the challenge of anticipating potential technological advancements and market dynamics in the long run when establishing CI benchmarks. To accommodate documented rapid advances in transportation fuel decarbonization that have already occurred, and which could occur again, the Proposed Amendments include both a near-term step-down in CI benchmark stringency (9%) in 2025, and an Automatic Acceleration Mechanism (AAM).

Staff is proposing to include an Automatic Acceleration Mechanism (AAM) to increase the stringency of the CI benchmarks of the program when specific regulatory conditions are satisfied. Under the current staff proposal, if activated, the AAM would advance the upcoming year's CI benchmark, and all subsequent years by one year. This can only be triggered once a year. For example, if the AAM is activated in 2029 based on 2028 LCFS reporting, the 2030 CI reduction target would be increased to 34.5%. An AAM can support the deeper transportation sector decarbonization needed through mid-century by increasing regulatory clarity for the market, acting alongside existing provisions that also help to provide program certainty, such as the maximum credit price and the Credit Clearance Market (CCM). The AAM would be triggered when the credit bank to average quarterly deficit ratio exceeds three and credit generation exceeds deficit generation based on the prior year's reporting.

Market conditions that meet both conditions would result in the AAM being activated. As described above, this reasonably foreseeable compliance response would result in future compliance targets moving forward one year. Impacts to resource categories in this EIA would not change in a scenario where the AAM is activated but could potentially happen a year earlier than under the existing proposed CI targets schedule. As such, the compliance responses and impacts to resource categories in this EIA describe the impacts associated with the Proposed Targets and a situation in which the AAM is activated and the CI target schedule is accelerated by one year.

2. Biomethane Crediting

Biomethane is currently eligible to generate credits in the LCFS program when used as a transportation fuel. Capturing methane is critical for achieving California's climate targets, including SB 32[16] and SB 1383 (Lara, Chapter 395, Statutes of 2016),[17] which focuses on 2030 climate goals, and AB 1279, which focuses on 2045 climate goals. However, the 2022 Scoping Plan Update indicates biomethane will be primarily needed for sectors outside the transportation sector instead of its current use as a vehicle fuel, given the overall path to zero-emission vehicle technology and the proliferation of low-carbon liquid fuels available in the near term. Therefore, staff is proposing the following

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[16]Forty percent reduction from a 1990 statewide GHG inventory by 2030.[17] Forty percent reduction in methane, 40% reduction in hydrofluorocarbons, and 50% reduction in anthropogenic black carbon below 2013 levels by 2030.

[17] Forty percent reduction in methane, 40% reduction in hydrofluorocarbons, and 50% reduction in anthropogenic black carbon below 2013 levels by 2030.

amendments to biomethane crediting, which will provide strong support for investment in biomethane capture in the near term, while aligning with the broader direction of the 2022 Scoping Plan Update to shift to production of hydrogen or as an end-use in other sectors outside transportation.

a) Phase Out Biomethane Combustion Crediting

For projects that break ground after December 31, 2029, staff is proposing to phase out pathways for crediting biomethane used in CNG vehicles after December 31, 2040. Pathways for biomethane used to produce renewable hydrogen would be eligible to receive credits until 2045. This concept aligns with the overall transition to non-combustion transportation technology highlighted in the 2022 Scoping Plan Update, as well as the shifting of biomethane resources to hydrogen production.

b) Avoided Methane Emissions

Staff is proposing to reduce the total number of crediting periods for avoided methane emissions crediting to two, rather than three consecutive 10-year periods for projects that break ground prior to January 1, 2030, and to include new regulatory provisions for projects that break ground after December 31, 2029. For projects that break ground after December 31, 2029, staff is proposing that pathways for avoided methane crediting be available until 2040 for biomethane used as a transportation fuel, and until 2045 for biomethane used to produce hydrogen.

c) Deliverability Requirements

Staff is proposing that pathways for bio-CNG, bio-LNG, and bio-L-CNG vehicles would need to demonstrate physical flow to California after December 31, 2037, if the Executive Officer approves a gas system map identifying interstate pipelines and their majority directional flow based on specified flow data by July 1, 2026. The proposed deliverability requirements also would not apply to biomethane matched to hydrogen fuel pathways participating in the LCFS program.

3. Project-Based Crediting

Staff is proposing changes to the project-based crediting provisions to align with the 2022 Scoping Plan Update to reduce GHG emissions across the economy while recognizing the broader trend away from fossil fuel production in tandem with demand. Specifically, staff is proposing to phase out crediting of petroleum projects by 2040.

In addition, staff is proposing to limit LCFS credit generation eligibility for direct air capture (DAC) projects to projects located in the United States. Focusing on projects located in the United States would align the LCFS with federal incentives for DAC projects, which also requires projects be within the United States and would support achieving national and State climate goals.

4. Book-and-Claim of Hydrogen

Indirect accounting via book-and-claim of low-CI hydrogen used as a transportation fuel or in the production of a transportation fuel is not allowed within the scope of the current book-and-claim provisions. However, the 2022 Scoping Plan Update calls for accelerating the transition to hydrogen use in support of achieving carbon neutrality. To incentivize the production and use of low-CI hydrogen, staff proposes to expand the existing book-and-claim provisions to include low-CI hydrogen injected into a dedicated hydrogen pipeline physically connected to California.

5. Remove Eligibility of Fossil Fuel-Derived Hydrogen

Staff is proposing to remove credit generation eligibility for hydrogen produced from fossil fuels, effective January 1, 2031. The 2022 Scoping Plan Update identified a need for low-carbon, renewable hydrogen for the transportation sector (among other sectors) to displace fossil fuels in support of achieving the State's greenhouse gas emission reduction goals. The 2022 Scoping Plan Update scenario did not include hydrogen produced from fossil fuels, with or without carbon capture as low-carbon, renewable hydrogen. Instead, it identified as low carbon and renewable hydrogen produced through steam methane reformation of biomethane, electrolysis, and biomass gasification. Staff is proposing to remove LCFS crediting eligibility for hydrogen produced from fossil fuels at the end of 2030 to align with the current operational timeline for projects funded under the hydrogen hubs grants, which will expand the supply of renewable hydrogen in California.

6. Capacity Crediting for Zero-Emission Vehicle Infrastructure for Heavy-Duty Vehicles

Staff is proposing to expand the current ZEV infrastructure crediting provisions by adding crediting for heavy-duty (HD) vehicle infrastructure. Traditionally, the LCFS provided credits for dispensed fuel, but in the 2018 LCFS rulemaking, the Board approved the ZEV infrastructure provisions to support rapid buildout of hydrogen refueling and fast charging stations. Stations approved under the Hydrogen Refueling Infrastructure (HRI) and Direct Current Fast Charging Infrastructure (FCI) provisions can receive additional credits in the early years of ZEV adoption when fewer vehicles are on the road, based on their unused refueling capacity. The programs have been successful to date in incentivizing ZEV infrastructure buildout in the light-duty vehicle sector, and staff is proposing to develop a similar provision to support ZEV refueling of HD ZEVs. This provision is identified as a key strategy for supporting the transition to HD ZEVs in the 2022 Scoping Plan Update, and infrastructure development is key to implementation of critical vehicle regulations such as the Advanced Clean Fleets regulation.[18] A HD HRI

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[18] California Air Resources Board, *Advanced Clean Fleets Board Resolution 23-13.* April 27, 2023. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2023/res23-13.pdf*

and FCI provision would encourage buildout of an early network of heavy-duty truck refueling stations by supporting station economics while the HD ZEV populations are low and would naturally phase out as refueling demand increases.

7. Continue Capacity Crediting for ZEV Infrastructure for Light-Duty Vehicle and Include Medium-Duty Vehicle Charging

The current light-duty ZEV infrastructure crediting provisions sunset at the end of 2025. As the State transitions to widespread ZEV deployment, it is imperative that light-duty refueling infrastructure incentives be expanded to include medium-duty vehicles, which have similar refueling needs and characteristics. Therefore, staff is proposing to modify the existing HRI and FCI provisions to combine both light--duty vehicle and medium-duty vehicle refueling. These provisions are designed to accelerate deployment of ZEV infrastructure both for consumers and businesses with light- and medium-duty vehicles.

8. Changes to Eligibility of Biomass-based Diesel

Staff is proposing to stop accepting applications for new biomass-based diesel fuel pathway applications starting on January 1, 2031, contingent on successful implementation of California's medium- and heavy-duty (MHD) zero emission vehicle regulations. This proposal is consistent with the State's goal of transitioning to zero emission technology and aligns biofuel policy with progress on ZEV deployment in the diesel pool. The proposal does not phase out existing biomass-based diesel fuel pathways, which may still report under their previously-certified CIs.

In addition, staff is proposing to provide credits for biomass-based diesel produced from virgin soybean oil and canola oil for up to 20 percent of annual biomass-based diesel reported on a company-wide basis. Quantities of soybean or canola oil biomass-based diesel in excess of 20 percent would be given the carbon intensity for the applicable year's diesel fuel benchmark from Table 2 of the LCFS regulation, or the certified carbon intensity of the applicable fuel pathway; whichever is higher. As manufacturers comply with increasing ZEV sales requirements and as California prioritizes waste feedstocks and advanced decarbonization technologies, the State must ensure that other regions are able to also access increasing volumes of low-carbon alternative fuels. California expects that overall diesel demand will decline in the State over the coming decades due to the State's portfolio of ZEV and clean fuel polices. This proposed addition allows for California to displace up to 100% of the State's current fossil diesel demand with cleaner alternative diesel. The proposed addition also avoids sending a long-term signal for virgin soy or canola oil to serve California demand. For companies that already have a certified fuel pathway prior to the effective date of the amendments and for which the percentage of biomass-based diesel produced from virgin soybean oil or canola oil was greater than 20 percent of combined reported biodiesel and renewable diesel quantities for that company's 2023 LCFS reporting, this provision would take effect starting January 1, 2028, to provide time to adjust feedstock supply contracts as needed. All other companies would be subject to this requirement upon the effective date of the amended regulation.

9. Provide an Opportunity for Automakers to Generate Base Credits

Staff is proposing to allow original equipment manufacturers (OEMs) of zero emission vehicles to generate a percentage of base credits for residential electric vehicle charging. OEMs would be required to utilize these credit revenues to promote and support transportation electrification in California. The Executive Officer would have discretion to allow credit generation for OEMs based on the percentage of ZEV sales of model year 2024 vehicles.

10. Sustainability Criteria for Crop-Based Biofuels

The current LCFS regulation uses land use change emissions estimates by feedstock, which were last assessed between 2013-2015 through an extensive expert workgroup. The existing regulatory provisions make fuel pathways from crop-based feedstocks more carbon intensive and disincentivize sourcing biofuel feedstocks from crops and regions with land-use change risks.

To reduce the risk that rapid expansion of biofuel production and biofuel feedstock demand could result in deforestation or adverse land use change, CARB staff are proposing additional guardrails on the use of crop-based feedstocks for biofuel production. Specifically, CARB staff are proposing to require pathway holders track crop-based and forestry-based feedstocks to their point of origin and require independent feedstock certification to ensure feedstocks are not contributing to impacts on other carbon stocks like forests. CARB staff are also proposing to remove palm-derived fuels from eligibility for credit generation, given palm oil has been demonstrated to have the highest risk of being sourced from deforested areas. Palm-derived fuel transactions have not been reported under the program or received any credits to-date.

Staff is proposing that sustainability requirements take effect in phases. The first milestone beginning in 2026 is for fuel producers to collect and submit supply chain data including spatial data of farm boundaries where feedstocks are sourced. Additionally, fuel producers must maintain an attestation letter signed by the fuel producer that assures feedstocks have not been sourced from lands that were converted after 2008.

The next milestone beginning in 2028 is for fuel producers to obtain third-party certification that, at a minimum, ensures feedstocks are not sourced on lands converted after 2008. Staff proposes that the list of certification schemes recognized by the European Union Renewable Energy Directive (EU RED) be automatically accepted for these purposes, owing to similar no-deforestation/no-conversion requirements under the EU RED. Other certification schemes that meet the criteria listed in subsection 95488.9(g)(5) will also be considered for approval by the Executive Officer. The final milestone beginning in 2031 requires sustainability certification of all biomass feedstocks or process energy by a third-party approved by the Executive Officer. Additionally, staff proposes to add specification of the geographic region to Table 6, of the current regulatory text,[19] identifying where land use change (LUC) carbon intensity was modeled for specific feedstock/fuel combinations. Table 6 LUC values were estimated through the GTAP and AEZ-EF modeling framework developed by CARB with input from an expert working group in 2010 and were updated during CARB's re-adoption of the LCFS program in 2015. GTAP uses economic and trade data to model the land requirements—i.e., the amount of forest, pasture, and cropland converted—to meet an increase in biofuel demand. It estimates these market-mediated land conversions within a focal region (i.e., domestic LUC) and elsewhere (i.e., world-wide LUC), which are used as inputs for the AEZ-EF model to estimate the associated GHG emissions based on regional carbon stocks. LUC carbon intensity for feedstocks from regions other than the regions modeled may not be equivalent with the Table 6 values for those feedstocks shown. The LUC carbon intensity of a given crop feedstock may vary widely based on land use practices and local carbon stocks in the region where it is produced.

To reflect this variability, the Proposed Amendments incorporate a mechanism to assign more conservative LUC carbon intensity values to feedstock/fuel combinations from regions with higher LUC risk. This proposal is informed by the increasing number of fuel pathway applications CARB has received involving crop-based feedstocks from regions other than those previously modeled in 2015 that may not demonstrate equivalency with Table 6 values. Staff's proposal aims to provide more granularity to LUC carbon intensity values. For feedstock/fuel combinations from regions not listed in the updated Table 6, staff proposes to conduct an empirical assessment to determine a conservative LUC value based on historical land conversions for a given feedstock. The empirical/regional LUC carbon intensity of a given feedstock/fuel combination will be compared to its respective modeled/global LUC carbon intensity value in Table 6, and the more conservative value will be assigned, as regional LUC is a subset of total LUC.

E. Compliance Responses Associated with the Proposed Amendments to the Low Carbon Fuel Standard

The following provides an illustrative, reasonably foreseeable compliance response scenario to achieve a 90% reduction in average CI by 2045 under the Proposed Amendments. As discussed above, the LCFS is based on a system of credits and relies on a wide variety of possible compliance responses to achieve the proposed reductions in CI. Compliance with the LCFS is primarily met by increasing the availability and use of low-carbon transportation fuels in California and reducing the greenhouse gas intensity of the existing transportation fuels used in California. The compliance scenario described in this section is based on assumptions that CARB staff has determined to be

[19] Cal. Code Regs., tit. 17, § 95488.3.

reasonably foreseeable considering existing fuel types and sources, recent fuel supply trends, and anticipated production and transportation capacities in coming years. Actual compliance responses in response to the Proposed Amendments may vary from those set forth here because fuel producers and suppliers would ultimately determine how the required reduction in CI is achieved. Innumerable variations in these compliance responses could be posited as possible outcomes of the Proposed Amendments; therefore, the scenarios presented by staff are referred to as “illustrative” rather than “predictive” or “forecasted.”

Staff conducted an in-depth scenario analysis that informed possible compliance schedules through 2045. The compliance responses described here are based on a reasonable range of assumptions, the modeling results, stakeholder feedback, and information obtained from market reports on alternative fuel technology development, and, therefore, provide a sound basis for evaluating the Proposed Amendments’ reasonably foreseeable environmental impacts. Notably, the compliance responses may be described in more detail, as appropriate, in the specific impact discussions in Chapter 3.0, below.

The precise production location and quantities of alternative fuels cannot be predicted with certainty because market interest may inform future feedstock supplies and production locations. However, for the purpose of this analysis, ethanol could be sourced from the following locations:

1. Corn ethanol: South Dakota, North Dakota, Colorado, Idaho, Kansas, New Mexico, Nebraska, California, Minnesota, Montana, Iowa, Illinois, and Texas;
2. Sugarcane ethanol: Brazil and Central America;
3. Molasses ethanol: Brazil and Central America;
4. Sorghum ethanol: South Dakota, Kansas, Nebraska, California, and Texas;
5. Sorghum/corn/wheat slurry ethanol: Kansas; and
6. Cellulosic ethanol: plants could be sited near areas where feedstock is available (e.g., fuel treatment projects such as tree thinning and collection of forest litter, in the Sierra foothills, Midwest, Northern California, Oregon, and Washington, and crop residues within the Midwest and the Central Valley of California). Additionally, bolt-on cellulosic ethanol processes can be added to corn ethanol facilities to convert corn kernel fiber to ethanol.

Feedstock sources for diesel substitutes and alternative jet fuel (AJF) could include:

1. Used cooking oil for renewable diesel, biodiesel, and AJF provided from sources throughout North America, Europe, and Southeast Asia;
2. animal fat for renewable diesel, biodiesel, and AJF from sources throughout North America, Southeast Asia, Australia, New Zealand, and Brazil;
3. Soy and canola farming and canola oil extraction in the United States, Canada and South America, followed by transportation of soy or canola oil to/within the U.S. (soy or canola oil could then be converted to biodiesel, renewable diesel or AJF and transported to blending stations for use in California motor vehicles; and
4. Biomethane that could be sourced primarily from landfills, dairy and swine farms, organic waste digesters (e.g., food scrap and urban landscaping waste), and wastewater treatment plants.

Feedstock sources for hydrogen production could include:

1. Natural gas provided from sources throughout North America;
2. Biomethane that could be sourced primarily from landfills, dairy and swine farms, organic waste digesters (e.g., food scrap and urban landscaping waste), and wastewater treatment plants;
3. Electricity for electrolysis; and
4. Biomass such as agriculture and forest residues for gasification.

Feedstock sources for electricity production could include:

1. Natural gas provided from sources throughout North America;
2. Biomethane;
3. Water reservoirs;
4. Solar, wind, tidal, and geothermal energy; and
5. Biomass such as agriculture and forest residues.

In addition, various potential innovative technologies could result in new pathways including biodiesel/renewable diesel sourced from algae, synthetic fuels from CCS projects, creation of additional drop-in renewable biofuels from woody biomass from pyrolysis and Fischer-Tropsch synthesis. Because the LCFS regulation provides flexibility in the types of low-carbon fuels that can be credited, the ability to investigate and develop a full range of conceivable sources of fuels for the future is difficult; however, based on a series of factors grounded in CARB's current understanding of known and expected fuel pathways, CARB has developed one projected compliance response scenario to reflect what may reasonably occur under the Proposed Amendments. The following factors are considered to determine the types of fuels that would reasonably be expected for use in compliance with the proposed regulations:

1. CI value,
2. Feedstock cost and availability,
3. Regulatory requirements for zero-emission vehicle deployment
4. Compatibility with the existing vehicle fleet,
5. Physical/transportation routes for the fuel,
6. Available infrastructure, and
7. Economic feasibility.

CARB has developed a plausible scenario to quantify potential volumes and credits generated by low carbon alternative fuels and petroleum-based projects through 2045. This information is based upon the existing regulatory requirements for zero-emission vehicle deployment as well as reasonable assumptions on known fuel availability and is intended to provide an illustrative reasonably foreseeable scenario that could meet compliance standards. Figure 1 and Figure 2 contain plausible, illustrative quantities of alternative fuels and expected credit generation, respectively, through 2045 (see Appendix C-1 of the ISOR for additional background information used to create this illustrative scenario).

Figure 1: Low-CI Fuel Mix - Proposed Amendments

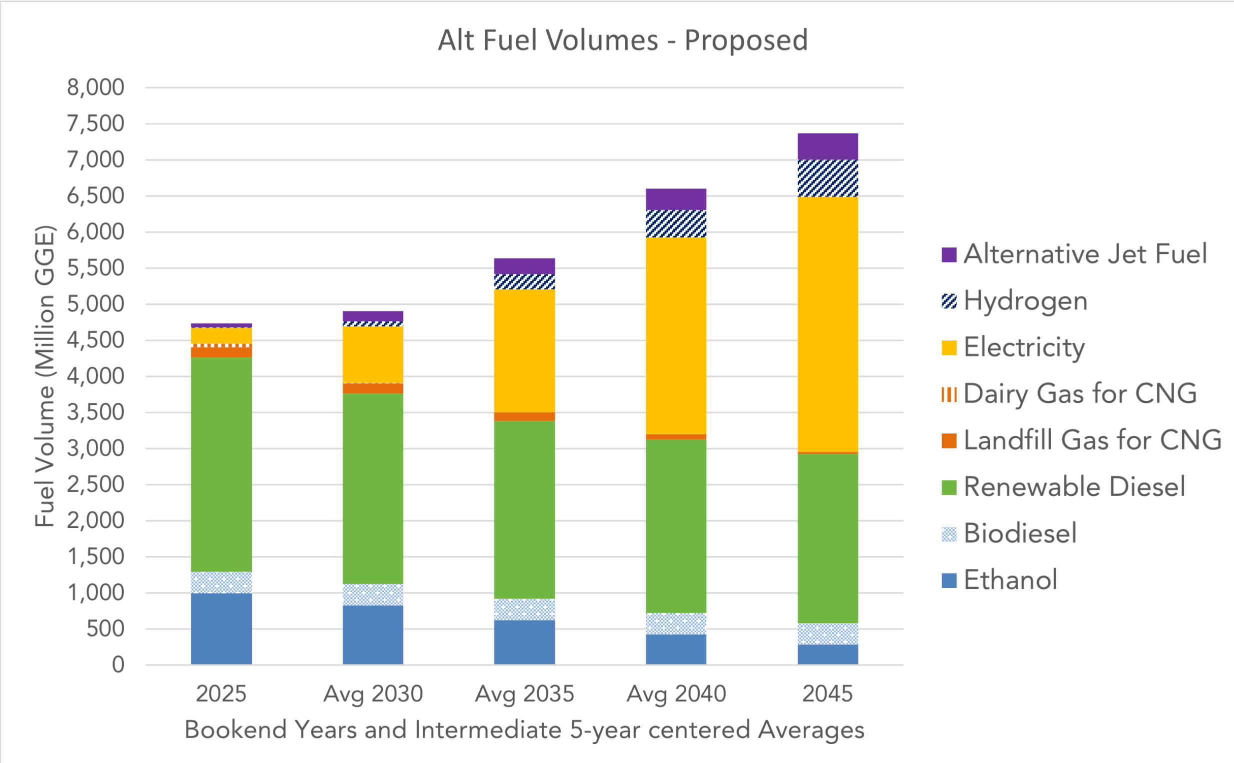
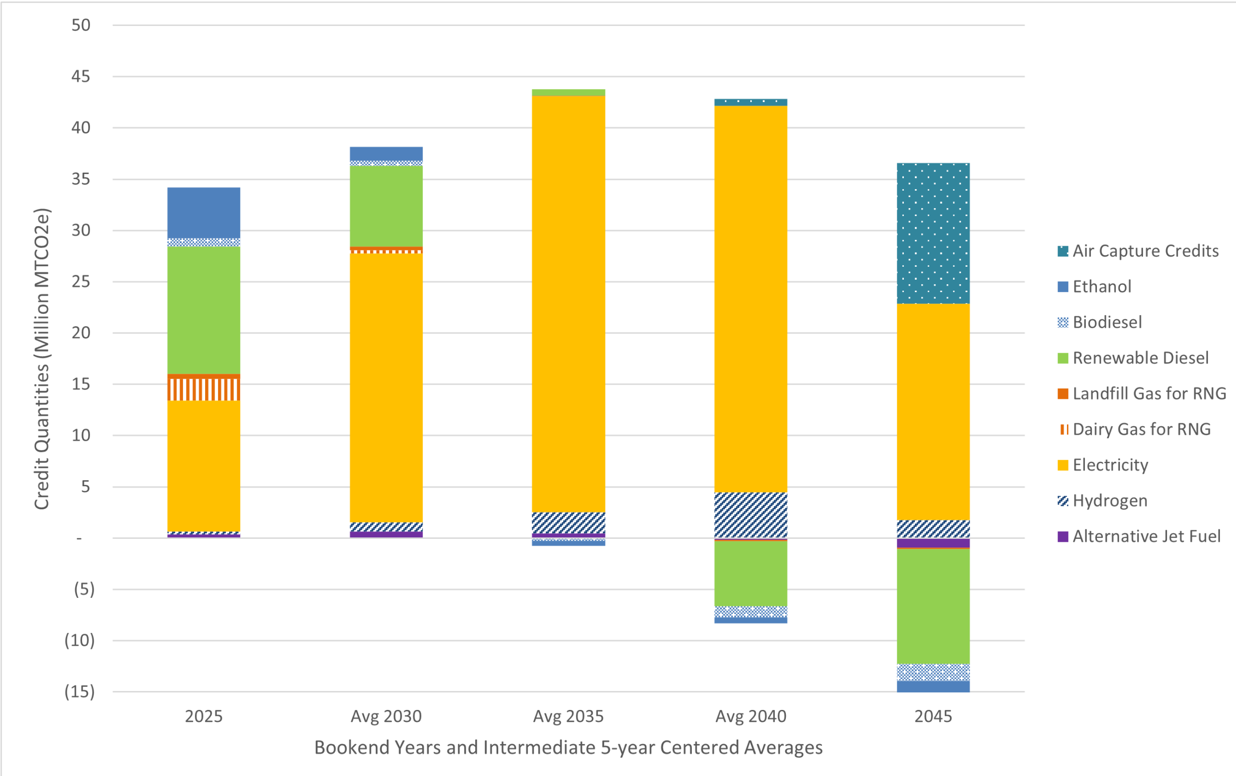


Figure 2: Credits Generated in the Proposed Amendments Scenario



1. Reasonably Foreseeable Technologies, Low-Carbon Fuel Types, and Feedstock Sources and Compliance Responses

The following section provides a discussion of the reasonably foreseeable technologies, low-carbon fuel types, and feedstock sources that could be developed to comply with the proposed CI requirements through 2045. In some cases, the fuels and feedstocks are already supplied to California under the current regulatory setting and would be expected to continue under the Proposed Amendments. Other reasonably foreseeable compliance responses that could occur because of implementation of the Proposed Amendments are also described.

a) Agriculture-Based Ethanol Production

1) Summary

Agriculture-based ethanol production involves the cultivation and production of crops for the primary use as ethanol fuel. Ethanol is currently blended in at up to 10% of gasoline by volume. CO_2 released when ethanol is used in vehicles is assumed to equal the CO_2 captured by the crop while growing and is considered “biogenic.” However, consideration of GHG emissions solely from fuel combustion does not provide a full life cycle analysis. GHGs are also emitted from ethanol production through agricultural practices to produce the ethanol crop, such as tillage and harvesting, agricultural chemical production, transport of crops, and the manufacture of ethanol from the crops.

2) Compliance Responses

Staff does not anticipate significant increases in the quantity of ethanol under the proposed LCFS amendments, assuming that ethanol continues to be blended into gasoline at up to 10% by volume. Potential compliance responses to the Proposed Amendments could include incremental improvements to ethanol production methods to reduce the CI of the fuel as the program benchmarks become more stringent. In addition, ethanol producers may choose to install CCS technology to further reduce their CI.

b) Renewable Diesel, Biodiesel, and Alternative Jet Fuel

1) Summary

The terms renewable diesel and biodiesel are defined according to the process by which they are produced and, thereby, result in fuels that have different physical properties. Biodiesel and renewable diesel are primarily derived from similar lipid feedstocks, but use varying production methods (transesterification and hydrogenation, respectively) such that renewable diesel is chemically identical to fossil diesel, while biodiesel must be blended in at defined amounts.

Renewable diesel and biodiesel may both be produced from various non-petroleum renewable sources. Used cooking oil, distillers corn oil, animal fat, soybean oil, and canola oil are the most typical feedstocks. Currently, feedstocks for renewable diesel and biodiesel are provided from sources throughout North America, Europe, and Asia.

AJFs are “drop-in” fuels made from fossil or renewable sources, which can replace fossil jet fuel without the need to modify aircraft engines and existing fuel distribution infrastructure. AJFs are expected to primarily be derived from the same renewable sources as renewable diesel, and AJF and renewable diesel are often produced at the same facility.

2) Compliance Responses

Potential compliance responses to the Proposed Amendments could include increases in finished fuel production and transport and increased feedstock processing and transport. This may include construction and operation of new facilities to produce renewable diesel, biodiesel, and AJF and collection and distribution of feedstocks to supply these facilities, or replace existing petroleum refineries. Production plants may be stand-alone or co-located at petroleum refineries.

c) Compressed Natural Gas and Liquefied Natural Gas from Both Fossil and Renewable Sources (Biomethane)

1) Summary

Fossil compressed natural gas (CNG) and liquefied natural gas (LNG) consist mostly of methane and are drawn from gas wells or in conjunction with crude oil production. They can be used in place of gasoline, diesel fuel, and propane. While both are stored forms of natural gas, the key difference is that CNG is stored at high pressure (in gaseous form) whereas LNG is stored at low temperatures, becoming liquid in the process. LNG is often used for transporting natural gas and converted to CNG before distribution to the end user. In the LCFS, these fuels are most often produced from North American gas fields, landfills, and dairy digesters (i.e., biogas as described below). The life cycle emissions that make up the fuel pathway of a specific CNG or LNG fuel include those associated with natural gas recovery, processing, transport and distribution, compression at refueling stations, and use in internal combustion vehicles.

Certain businesses produce organic waste that could be repurposed into a clean, renewable fuel source called biogas. Biogas is the raw gaseous mixture comprised primarily of methane and carbon dioxide produced by the anaerobic decomposition of organic matter, and once the biogas is conditioned to pipeline-quality natural gas, it is considered biomethane, or RNG. Biomethane is most frequently produced from the following biogas sources:

- Landfills,
- Dairy and swine facilities,
- Food processing companies, and
- Wastewater treatment plants.

Landfills provide a source of biomethane that may be used to comply with the LCFS. In 2010, CARB approved the regulation to reduce methane emissions from municipal solid waste landfills. This measure requires the installation and proper operation of gas collection and control systems at active, inactive, and closed municipal solid waste landfills that control greater than 450,000 tons of waste-in-place and have been in operation after January 1, 1977. When derived from landfills, natural gas is first contained by using soil, compacted clay, geomembrane, biocovers, or other surface covers. Collection and control systems, which are typically vertical wells or horizontal trenches, are used to capture the gas. Performance standards for the gas collection and control systems and specific monitoring requirements ensure that the system is maintained and operated in a manner to minimize methane emissions. In addition, leak standards for gas collection and control system components, a monitoring requirement for wellheads, methane destruction efficiency requirements for most control devices, surface methane emission standards, and reporting requirements are included in the regulation.

Biomethane is also collected at dairy and swine operations, and many dairy or swine manure biogas-to-biomethane pathways, often referred to as biogas-to-Renewable Natural Gas (RNG) pathways, have been certified under the current LCFS. Such pathways incentivize dairy cattle and swine farms to install biogas control systems for manure management and incentivize using captured biomethane as a vehicle fuel or for conversion to electricity for EV charging, or as a feedstock for producing hydrogen. Though the LCFS incentivizes biogas control systems for manure management, for the reasons outlined below, changes to herd size, dairy expansion, or new dairy cattle facilities are speculative and not reasonably foreseeable compliance responses for the Proposed Amendments.

The U.S. dairy industry has shifted over the last quarter century to fewer, larger dairies to achieve economies of scale, and production efficiency improvements have allowed the sector to meet growing demand without increasing the total number of animals.[20,21,22] These overall trends are expected to continue in the near term, independent of the Proposed Amendments.

The total U.S. dairy cattle population has remained relatively flat over the past 25 years,[23,24,25,26,27] and statewide populations have declined in the majority of states, including California, where the number of milk cows reached a peak of 1.84 million

[20] Food and Agriculture Organization of the United Nations. *Dairy Market Review – Emerging trends and outlook in 2023*. 2023. Rome. https://www.fao.org/3/cc9105en/cc9105en.pdf

[21] Organization for the Economic Co-operation Development, *OECD-FAO Agricultural Outlook 2020-2029*. July 16, 2020. https://www.oecd-ilibrary.org/oecd-fao-agricultural-outlook-2020-2029-summary-english_ece4ff0c-en.pdf?itemId=%2Fcontent%2Fcomponent%2Fece4ff0c-en&mimeType=pdf

[22] Brito, L.F. et al. (2021) *Review: Genetic selection of high-yielding dairy cattle toward sustainable farming systems in a rapidly changing world*, Animal, Volume 15, Supplement 1, 2021, 100292, ISSN 1751-7311. https://doi.org/10.1016/j.animal.2021.100292

[23] United States Department of Agriculture, National Agricultural Statistics Service, *2002 Census of Agriculture – United States Data*, p. 20, 2002. https://agcensus.library.cornell.edu/wp-content/uploads/2002-United_States-UnitedStatesData-Table-17.pdf.

[24] United States Department of Agriculture, National Agricultural Statistics Service, *2007 Census of Agriculture – United States Data*, p. 21, 2007. https://agcensus.library.cornell.edu/wp-content/uploads/2007-United_States-st99_1_017_019.pdf.

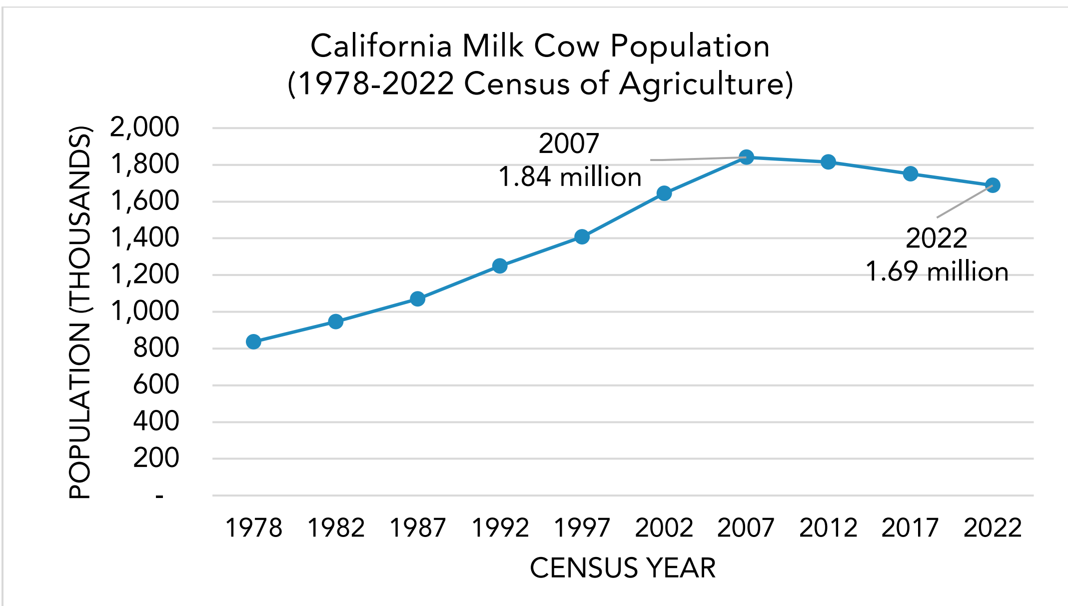
[25] United States Department of Agriculture, National Agricultural Statistics Service, *2012 Census of Agriculture – United States Data*, p. 21, 2012. https://agcensus.library.cornell.edu/wp-content/uploads/2012-United-States-st99_1_017_019.pdf.

[26] United States Department of Agriculture, National Agricultural Statistics Service, *2017 Census of Agriculture – United States Data*, p. 23, 2017. https://www.nass.usda.gov/Publications/AgCensus/2017/Full_Report/Volume_1,_Chapter_1_US/st99_1_0017_0019.pdf.

[27] United States Department of Agriculture, National Agricultural Statistics Service, *2022 Census of Agriculture – United States Data*, p. 19, 2022. https://www.nass.usda.gov/Publications/AgCensus/2022/Full_Report/Volume_1,_Chapter_1_US/st99_1_017_019.pdf.

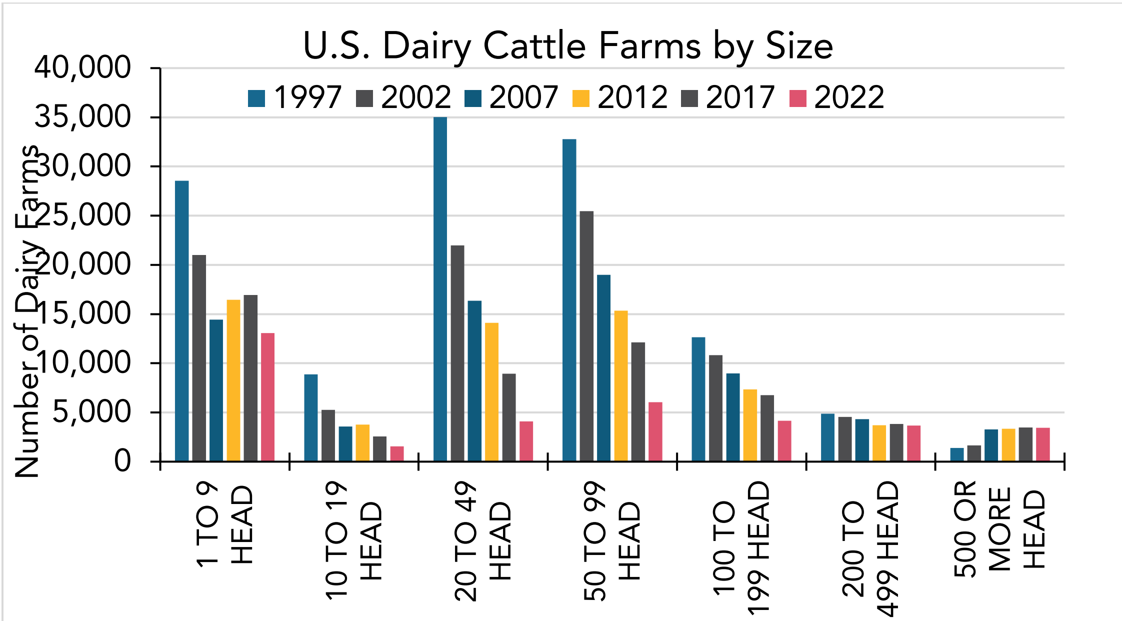
around 2008,[28] according to USDA Census of Agriculture (Ag Census).[29, 30] According to the most recent Ag Census conducted in 2022, since 2008, the number of milk cows in California has steadily declined year over year more than 8% to approximately 1.69 million, despite programs incentivizing digesters becoming available during that time.[31] Populations have grown significantly (greater than 5% increase) in only seven major dairy-producing states over the decade from 2012 to 2022 (Colorado, Idaho, Iowa, Kansas, Michigan, South Dakota, and Texas), some of which have implemented incentives or regulations that facilitate new dairy operations and expansions at existing operations. At the same time, the average farm size (head of mature cattle per farm) has increased in nearly all states across dairy herd size classes.[32]

Figure 3: California Milk Cow Population Growth Trends (1978 – 2022)



[28] California Air Resources Board, *California's 2000-2014 Greenhouse Gas Emission Inventory*, at p. 96, 2016. https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/ghg_inventory_tsd_00-14.pdf.
[29] United States Department of Agriculture, National Agricultural Statistics Service, *2007 Census of Agriculture – State Data – California*, p. 21, 2007. https://agcensus.library.cornell.edu/wp-content/uploads/2007-California-st06_1_017_019.pdf.
[30] United States Department of Agriculture Research Service, Njuki, *U.S. Dairy Productivity Increased Faster in Large Farms and Across Southwestern States*, March 22, 2022. https://www.ers.usda.gov/amber-waves/2022/march/u-s-dairy-productivity-increased-faster-in-large-farms-and-across-southwestern-states/
[31] For example, the biofuels pathway through the LCFS program started in 2017, and the California Department of Food and Agriculture providing grants for digesters in 2014.
[32] Ibid, United States Department of Agriculture National Agricultural Statistics Service in Footnotes 23-27.

Figure 4: Shifting U.S. Dairy Cattle Farms by Size Trends (1997 – 2022)



The USDA Economic Research Service (ERS) has extensively analyzed consolidation and found that farms with larger herd size classes consistently earned substantially higher net returns than smaller herds.[33] Increasing herd sizes, coupled with increasing adoption of technologies to improve production efficiency,[34] result in improved financial returns per unit of milk produced for facilities achieving greater economies of scale, even at reduced commodity prices paid to producers.[35,36,37] Larger herd sizes allow facilities to generate increased commodity revenues while reducing the economic impact of production costs driven by a variety of factors including costs for animal feed, fuel, labor, technology adoption, environmental compliance, and commodity marketing

33 MacDonald, James M., Jonathan Law, and Roberto Mosheim. *Consolidation in U.S. Dairy Farming,* ERR-274, July 2020. *https://www.ers.usda.gov/webdocs/publications/98901/err-274.pdf*. Net returns are essentially the difference between production costs and prices paid to producers. Production costs include costs paid by producers for feed, fuel, labor, veterinary services, and regulatory compliance, and can also be affected by broader economic conditions (e.g., inflation, interest rates, and economic uncertainty).

34 Cole, John, *The Effects of Breeding and Selection On Lactation In Dairy Cattle,* Anim Front. June 2023; 13(3): 62–70..Published online June 14, 2023. *https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10266753/*

35 United States Department of Agriculture Economic Research Service, J. Macdonald, *Scale Economies Provide Advantages to Large Dairy Farms,* August 3, 2020. https://www.ers.usda.gov/amber-waves/2020/august/scale-economies-provide-advantages-to-large-dairy-farms/

36 U.S. Department of Agriculture, Economic Research Service, Njuki, Eric, *Sources, Trends, and Drivers of U.S. Dairy Productivity and Efficiency*, ERR-305, February 2022. https://www.ers.usda.gov/publications/pub-details/?pubid=103300.

37 U.S. Department of Agriculture, Economic Research Service, *Consolidation in U.S. Dairy Farming,* July 2020. https://www.ers.usda.gov/publications/pub-details/?pubid=98900

by spreading these costs across more animal units. This basic economic fact, and not actions taken in response to the LCFS, appears to drive decisions to expand. CARB staff have also extensively analyzed data from California dairies and concluded that there is no statistical relationship between the installation of digesters and dairy growth rates.[38] According to ERS, larger operations appear to realize lower average costs in part by investing in technology, such as computerized milking and feed delivery systems, to increase yields. Likewise, it is reasonable to assume that larger operations are more likely to invest in technology such as digesters and solid-liquid separation systems to improve manure management and reduce costs for synthetic fertilizer and animal bedding. Additionally, solid-liquid separation systems implemented in conjunction with anaerobic digestion systems can facilitate improved nutrient management and help reduce off-site export of excess nutrients and solids. Manure management is one of several practices identified by USDA that contribute to productivity and efficiency.[39]

Though the dairy sector has exhibited a trend of consolidating, whether, and, if so, how, a dairy operation would expand or a new dairy operation would be developed is speculative because it is subject to a fact-intensive, complex economic determination relying upon local, unforeseeable circumstances. In determining whether to develop a new dairy or expand an existing dairy, operators must consider a variety of factors, including development costs (including design, construction, equipment, ongoing operational, compliance, and financing availability and costs), potential revenue streams and return on investment, geography, available land appropriate for expansion and for manure application, and state and local environmental regulation. Existing operations may not be appropriate for expansion or installation of a digester because the land is not conducive, which is determined on a case-by-case basis. In addition, any herd size expansion requires significant environmental[40,41] and conditional use permitting, especially in California, which has enacted the most stringent environmental, air, and water quality protection regulations in the nation. In contrast, some states actively incentivize new dairies and expansions of existing dairies using economic benefits like

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[38] California Air Resources Board, California Dairy Sector Workshop staff presentation, https://ww2.arb.ca.gov/sites/default/files/2024-08/CARB_Dairy_Sector_Workshop_Staff_Presentation_08-22-2024.pdf (Accessed August 12, 2024).

[39] U.S. Department of Agriculture, Economic Research Service, Njuki, Eric. February 2022. Sources, Trends, and Drivers of U.S. Dairy Productivity and Efficiency, ERR-305, https://www.ers.usda.gov/publications/pub-details/?pubid=103300

[40] San Joaquin Valley Air Pollution Control District (SJVAPCD) is responsible for air quality permitting most dairy operations in California. More information on the SJVAPCD permitting process and requirements available at: https://ww2.valleyair.org/permitting/dairy-permitting/

[41] For example, confined animal facilities are subject to statewide water quality control regulations. See, *e.g.*, Cal. Code Regs., tit. 27, § 22560 *et. seq*. California State Water Resources Control Board regional board 5 is responsible for water quality permitting for most dairy operations in California. More information on regional board 5 permitting process and requirements available at: https://www.waterboards.ca.gov/centralvalley/water_issues/confined_animal_facilities/program_regs_requirements/dairy/

investment tax credits or regulatory changes such as those enacted in Iowa.[42] In addition, CARB has conducted extensive data collection and evaluation on California dairies, and the data evaluation did not find that the existing LCFS Regulation has caused dairy sector trends toward herd size expansion.[43] Evaluating the potential for the Proposed Amendments to cause herd size expansion would require making multiple inferences about what changes in the economic, regulatory, and operating landscape led to a change in a dairy's operation, which would require data about business owner future decision-making to differentiate and isolate. Any statewide animal population increases, facility herd expansions, or new dairy cattle facilities are expected to be the result of the above-described longstanding economic trends throughout North America or other factors and are not expected to be reasonably foreseeable compliance responses to the Proposed Amendments. Therefore, no further analysis is required. CARB will continue to use the best available data to improve methane reduction progress tracking, including monitoring changes in animal populations. Likewise, dedicated digesters at wastewater treatment plants are incentivized to capture methane and divert a portion of organic wastes from landfills and create useful byproducts, such as electricity and biofuels. Dedicated digesters process various types of organic wastes, including food waste and urban landscaping waste into biogas that can be upgraded to pipeline-quality RNG. It is anticipated that some of California's existing, and potentially new, wastewater treatment plants that operate anaerobic digesters may install additional equipment to collect, store, and co-digest regionally sourced organic wastes (i.e., food, cooking grease by-products, and agricultural produce waste), and install other equipment and infrastructure to capture methane gas and produce biogas that can be used for beneficial purposes. Captured biogas could potentially be used for on- or off-site electricity generation or cleaned and compressed for use as a natural gas pipeline supplement or as a vehicle fuel. The increased capture of methane and production of biogas would potentially result in the installation and operation of a variety of equipment and infrastructure at wastewater treatment plants and dairy and swine operations.

The Proposed Amendments support installation of biogas capture systems throughout North America. However, the proposed amendments require pathways for bio-CNG, bio-LNG, and bio-L-CNG vehicles in order to demonstrate physical flow to California after December 31, 2037, if the Executive Officer approves a gas system map identifying interstate pipelines and their majority directional flow by July 1, 2026, and phase out the existing avoided methane credit. These changes are likely to result in

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[42] In 2021, Iowa enacted House File 522, which could allow dairies to exceed confinement capacity if they install an anaerobic digester to treat all manure. News sources also report the permitting and regulatory environment in South Dakota as "friendly" to agricultural operations such as dairy farms. See, e.g., https://www.argusleader.com/story/news/2021/03/04/south-dakota-emerging-major-player-dairy-industry-heres-why/4577419001/ (Accessed August 2, 2024).

[43] California Air Resources Board, *California Dairy Sector Workshop* staff presentation, https://ww2.arb.ca.gov/sites/default/files/2024-08/CARB_Dairy_Sector_Workshop_Staff_Presentation_08-22-2024.pdf (Accessed August 14, 2022).

some biomethane supplies shifting to other uses outside of the current predominant use as a combustion vehicle fuel.

2) Compliance Responses

Potential compliance responses to the Proposed Amendments would generally include construction of infrastructure needed to collect biogas and produce and transport biomethane. Biogas collected from the anaerobic digestion of organic matter (mostly methane and CO_2) would be purified to pipeline quality biomethane and injected into pipeline, or made available on site at the facility to fuel CNG-fueled vehicles. Pipeline-quality fuel from the purified biomethane (i.e., product gas) would be compressed and injected into the utility company’s natural gas transmission grid at a connector located near the processing facility. Another potential compliance response is additional production of low-CI electricity or hydrogen from biomethane derived from dairy operations. The LCFS modeling assumes use of fuel cells to generate this electricity, which do not rely on combustion.

d) Cellulosic Ethanol

1) Summary

Cellulosic ethanol is a fuel derived from the structural parts of plant materials (e.g., plant stems, barks, and leaves composed largely of cellulose). As described above, under Agriculture-Based Ethanol Production, blending gasoline with ethanol could reduce the CI values of the finished fuels. Cellulosic ethanol could be produced from a variety of biomass sources, including, but not limited to, farmed trees, forest waste, grasses, and inedible parts of plants. In cellulosic ethanol plants, cellulose from biomass is converted into ethanol through an enzymatic process or a thermo-chemical conversion. The lignin portion could be burned in ethanol plants to provide needed steam. Some amount of extra electricity could be generated in cellulosic plants and exported to the electrical grid.

“Bolt-on” facilities are another way to produce cellulosic ethanol. These units produce cellulosic ethanol from the fiber of the corn/sorghum kernel and are added to or co-located with existing corn ethanol biorefineries. Bolt-on configurations minimize capital expenditures by maximizing the utility of existing plant and unit operation assets—most notably using existing fermentation and distillation assets to convert cellulosic sugars to cellulosic ethanol. Additionally, shared supply chains and distribution channels help lower the investment risk.

Fuel pathways for cellulosic ethanol could include:

- Cellulosic ethanol from forest waste (including from U.S. Forest Service lands in the Sierra foothills, northern California, Oregon, and Washington);

- Cellulosic ethanol from crop residues (including from Central Valley of California and the Midwest); and
- Cellulosic ethanol from conversion of corn/sorghum kernel fiber at conventional corn ethanol facilities.

2) Compliance Responses

Potential compliance responses to the Proposed Amendments could include construction of bolt-on cellulosic processing units at conventional ethanol facilities, as well as construction of stand-alone processing plants that are likely to rely on hydrolysis and gasification procedures to produce ethanol. Collection of source materials for cellulosic ethanol production would be expected to increase, including collection of yard waste, or removal of forest litter. Co-generation systems could also be included in combination with construction of processing facilities.

e) Hydrogen

1) Summary

Hydrogen can be produced from several resources. Currently, most hydrogen is produced from steam reformation of methane. Electricity from the grid or from renewable sources can be used to generate hydrogen via electrolysis. Biomass may also be gasified to produce hydrogen. Biomass can be converted to hydrogen and other byproducts through a number of methods. Because growing biomass removes CO_2 from the atmosphere, the net carbon emissions of these methods can be low. Solar energy can directly or indirectly provide the energy to produce hydrogen. Wind-generated electricity can power water electrolysis to produce hydrogen, which could be used to fuel vehicles, or stored and then used in fuel cells to generate electricity during times of the day when the wind resource is low. Electricity can be used to split water into hydrogen and oxygen. This technology is well-developed and available commercially, and systems that can efficiently use renewable power are being developed.

2) Compliance Responses

Potential compliance responses to the Proposed Amendments could include the construction of new or expanded hydrogen production facilities, using steam methane reformation, electrolysis, or gasification technologies. This could include construction of new infrastructure such as new hydrogen pipelines to transport the hydrogen, or additional truck transport. In addition, additional hydrogen storage on-site at refueling stations or larger-scale storage off-site could be needed.

f) Electricity as Fuel

1) Summary

Most of the electricity consumed in California is generated by natural gas, nuclear energy, and from renewable sources of energy, including hydropower, biomass, wind, geothermal, and solar power.

Battery-electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) operating in all-electric mode do not produce tailpipe emissions. Over time production emissions associated with electricity for transportation will decline as California progresses to meeting the 50% renewable electricity requirements in SB 350 and 100% clean energy goal by 2045 in SB 1020, or potentially sooner if EV load is encouraged to be served using renewable sources including solar and wind by policies such as the Proposed Amendments.

Staff expects that the total quantity of electricity used in electric vehicles will increase primarily as a result of the Advanced Clean Cars II, Advanced Clean Trucks, and Advanced Clean Fleets regulations, and therefore the total electricity used as a transportation fuel in the business-as-usual baseline scenario of the LCFS modeling is the same as in the proposed amendments. However, the LCFS sends a strong incentive to reduce the CI of electricity used as a transportation fuel, particularly through the use of solar and wind renewable electricity pathways as compared to the California grid average. In addition, the LCFS directly incentivizes the installation and operation of electric fast charging infrastructure through the Fast Charging Infrastructure (FCI) provision of the regulation. The FCI provision is being expanded in the Proposed Amendments to apply to the trucking sector, and extended for continued use in the light-duty vehicle sector.

2) Compliance Responses

Reasonably foreseeable compliance responses would include the construction and operation of renewable energy production facilities and electric charging infrastructure incentivized by the new and expanded FCI provision in the Proposed Amendments. Expanded renewable energy production could include operation of new facilities, including wind, solar thermal, solar photovoltaic, geothermal, solid-fuel biomass, biogas, solar thermal steam production, hydrogen, pumped storage, battery storage, and hydroelectric systems (i.e., electricity generation associated with dams, run-of-river, or pumped storage facilities). The operation of wind, solar thermal, and solar photovoltaic energy would occur over large but yet-unknown expanses of land and water.

The build out of electric fast charging infrastructure, which is directly incentivized through the LCFS infrastructure credits, could include operation of new or expanding charging facilities, including construction of new charging stations and associated buildings, underground or aboveground electric cables, and substations.

g) Mechanical Carbon Dioxide Removal and Carbon Capture and Sequestration Actions

1) Summary

The Proposed Amendments continue to support the use of carbon capture and sequestration (CCS) in connection with transportation fuel production, and direct air capture (DAC) with carbon sequestration projects. DAC with sequestration is also still eligible for project-based CCS credits but is limited to projects within the United States. DAC with sequestration when attached to a fuel pathway is not limited to the United States.

2) Compliance Responses

Potential compliance responses to the Proposed Amendments could include the construction and operation of new facilities to capture ambient CO_2, modification of existing or construction of new industrial facilities to capture CO_2 emissions (CCS), and construction of new infrastructure, such as pipelines, wells, and other surface facilities to enable the transport and injection of CO_2 into a geologic formation for sequestration. Mechanical carbon dioxide removal and other CCS activities may also result in increased transportation, such as truck, rail, and barge transit to transport CO_2 from the direct air capture facilities and industrial facilities to the sequestration sites. The transport distances and pipeline construction requirements for the captured CO_2 would vary depending on the locations of specific direct air capture facilities and industrial sources of the captured CO_2 and proposed underground formations. On-site energy generation and storage to power the capture equipment are key mitigation strategies involving photovoltaic electricity generation, battery storage, and microgrid systems. Increased electricity demand would be met by increased generation, both on-site and off-site.

2. Potential Changes in Land Use, Shipment Patterns, and Infrastructure

In consideration of the potential for increased use of alternative fuels in California, staff anticipates that there are potential changes in land use, shipment patterns, and infrastructure needs that could occur because of the Proposed Amendments. These changes are summarized below.

a) Land Use Changes

1) Summary

As discussed in this chapter, biofuels rely on feedstock production and are driven by economic demand and supply factors associated with the market for these feedstock products. Feedstocks include byproducts of existing operations (e.g., animal fat, used cooking oil) and crops grown for biofuel or other commodity uses (e.g., corn, soy, and sugarcane). Both commodity crops and fuel ethanol, renewable diesel, alternative jet fuel, and biodiesel are traded among many countries in the world and are generally anticipated to trend toward increased quantities as demand for low-carbon fuel rises from decarbonization efforts being pursued by national and sub-national governments, as well as from voluntary efforts of individual companies.

Global equilibrium models and research for land use change have shown that crop type, projected crop yields, the assumed elasticity of food demand to price, and the assumed elasticity of crop area to price are all important.[44,45] For instance, a 2011 assessment of past effects of global biofuel demand found a connection between increased soybean cultivation and deforestation in Brazil.[46] Potential greenhouse gas emissions associated with land use change to produce biofuels were quantified through a robust public process to inform the 2015 rulemaking. These emissions estimates are added to the CI of crop-based biofuels before certification.

Additionally, the Proposed Amendments include sustainability criteria for crop-based feedstocks and forest biomass for biofuel production and a ban on palm oil derived fuel crediting, as outlined in the Project Description section above. The Proposed Amendments also end the acceptance of new biomass-based diesel fuel pathway applications after January 1, 2031, contingent on successful implementation of California's MHD ZEV regulations, as outlined in the Project Description section above. In addition, staff is proposing to provide credits for biomass-based diesel produced from virgin soybean oil and canola oil for up to 20 percent of annual biomass-based diesel reported on a company-wide basis. Taken together, these new provisions will reduce the potential risk of deforestation that could occur from the expansion of biofuel production and biofuel feedstock demand and create an even stronger incentive to utilize waste feedstocks.

2) Compliance Responses

Upstream production of agriculture-based feedstocks may result in direct and indirect land use change impacts. Direct land use change, in the context of biofuels, is defined as the displacement of existing cropland or conversion of native habitat to cropland solely to produce a biofuel crop. Indirect land use change occurs when displaced cultivation is relocated onto native habitat or other non-agricultural lands. In terms of determining carbon intensity (CI) values under the Proposed Amendments, both direct

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[44] California Air Resources Board, *LCFS Land Use Change Assessment*. (Accessed on September 19, 2023). https://ww2.arb.ca.gov/resources/documents/lcfs-land-use-change-assessment
[45] United States Environmental Protection Agency, *Model Comparison Exercise Technical Document*. June 2023. https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P1017P9B.txt
[46] Gao, Y., Skutsch, M., Drigo, R., Pacheco, P., & Masera, O. *Assessing deforestation from biofuels:* methodological *challenges*. 2011. Applied Geography, 31(2), 508-518. https://www.sciencedirect.com/science/article/abs/pii/S0143622810001220

and indirect land use changes are considered as part of the life cycle GHG emissions analysis.

Land use changes caused by increased demand for fuel feedstocks incentivized by the Proposed Amendments would likely occur across several continents, given the global nature of transportation fuels markets. The Proposed Amendments would incentivize fuels that have lower CI values than crude oil, including fuels made from sugarcane, sorghum, wheat, cellulosic sources, corn, canola, and soy. With continued increased demands on biofuel crops the Proposed Amendments could contribute to increased direct and indirect land use change to accommodate new croplands, but the likelihood of this is at least partially (and potentially fully) accounted for by the LUC scores added to crop-derived pathways.

Waste-based feedstocks, like used cooking oil (UCO) and animal fat, do not have additional LUC scores that are added to their CI value and made up 84% of all biomass-based diesel in the program from 2011 through 2022. The LUC scores for crop-based fuels add 12-70 grams per megajoule (g/MJ) to the pathway's CI score, making the CI of crop-based fuels higher relative to waste-based feedstocks. As the CI benchmark becomes more stringent each year, the program incentive for crop-based feedstocks declines, and pathways using these feedstocks will eventually become deficit-generating.

Demands for crop-based feedstocks are likely to be realized through cultivation of soy and canola feedstocks in Illinois, Iowa, Minnesota, Mississippi, Indiana, Nebraska, Kansas, Ohio, Arkansas, Canada and South America. However, the proposed regulation is not expected to result in significant increases in soy and canola feedstock utilization for biomass-based diesel, given that volumes in excess of 20 percent, which matches 2023 feedstock composition levels across all pathways, will not be eligible for crediting.

As discussed above, as demand for biofuel crops increases, it could displace production of food crops, resulting in conversion of both fallow and cultivated lands to biofuel feedstock crop production. However, ethanol volumes are expected to decrease over the course of the Proposed Amendments, as they are limited by the existing blend limit of 10% and would naturally phase down in tandem with gasoline demand reductions. In addition, the proposed crop-based biofuels sustainability criteria and changes to fuel pathway eligibility would additionally help protect against potential future land use impacts.

b) Changes to Fuel-Associated Shipment Patterns

1) Summary

In general, infrastructure already exists to support increased shipments of feedstock crops and fuels via rail and ocean-going vessels. As shown in Figure 1, demand in California for ethanol could decrease between 2025 and 2045, in tandem with an overall demand reduction in gasoline. This potential shift could result in a decrease in shipments of ethanol from existing sources (California, other states and Brazil). The proposed amendments would likely also increase demand for biomass-based diesel and alternative jet fuel. Increased levels of transport of diesel substitutes such as biodiesel and renewable diesel would be needed to meet the anticipated demand (see Figure 1).

2) Compliance Responses

Historically, these diesel substitutes have largely been produced outside of California and imported to the State. However, announced production capacity for renewable diesel and alternative jet fuel (AJF) in California has increased substantially in recent years, and it is likely that an increasing proportion of the renewable diesel and AJF demanded in future years of the program would be met by California sources. As a result, existing facilities could be expanded to accommodate general increases in production of these fuels. Additionally, new facilities could be constructed to accommodate the increased production of these fuels. Increasing demand for biodiesel and renewable diesel could result in increased rail, truck, and ocean-going shipment of these fuels into California.

c) Additional Infrastructure Needs

1) Summary

New production plants for renewable diesel, biodiesel, biodiesel additives, AJF, hydrogen, and biomethane could be constructed and operated to meet future demands. Similarly, construction and operation of future innovative technology facilities for drop-in renewable biofuels and Fisher-Tropsch diesel could be developed. Construction and operation of additional hydrogen stations, solar and wind electricity generation projects, and EV charging stations could also be developed to meet future demands and in response to the expanded hydrogen and electric charging infrastructure provisions. New pipelines for renewable natural gas and hydrogen could also be constructed to meet future increased demand for these fuels. Rail and trucking routes could also expand to transport these fuels into and throughout California.

2) Compliance Responses

Potential compliance responses to the Proposed Amendments (both generally and as specifically associated with credits for ZEV infrastructure) also consist of construction and operation of new hydrogen refueling and new DC fast charging infrastructure for both light-duty and MHD ZEVs.

Possible compliance responses from the Proposed Amendments could include installation of additional digesters at existing dairy/swine facilities in California and elsewhere in the United States. Installation of these facilities could result in localized short-term construction impacts.

Possible compliance responses from the Proposed Amendments could include projects at crude oil production facilities or at crude oil refineries. Such projects could include projects that qualify under the innovative crude, refinery investment, renewable hydrogen for refineries, and innovative low-energy/low-complexity refineries provisions of the regulation found in section 95489.

As the carbon intensity benchmark becomes more stringent, additional compliance responses may include the construction and operation of new biofuel production facilities, or conversion of crude oil production facilities and crude oil refineries, which are deficit generating, to biofuel production facilities. Retrofitting existing infrastructure could minimize the need for new greenfield infrastructure development for biofuel production and refining.

d) Carbon Capture and Sequestration at Alternative Fuel Production Facilities, Oil Fields, or Refineries

1) <u>Summary</u>

CCS is a process whereby CO_2 emissions are captured from large industrial sources, such as power plants, natural gas processing facilities, fertilizer plants, ethanol plants, and hydrogen plants, and transported and injected into underground geologic formations, such as depleted oil and gas fields or deep saline aquifers. In California, underground injection projects must be permitted by the U.S. Environmental Protection Agency (U.S. EPA) or the California Department of Conservation Geologic Energy Management Division (CalGEM). U.S. EPA issues Class VI Underground Injection Control permits, which apply to injection wells that are drilled for the sole purpose of CO_2 injection in an underground formation as part of a CCS project, without any other intended purpose. CalGEM issues Class II permits under regulatory authority granted by U.S. EPA pursuant to Underground Injection Control regulations. Class II permits apply to injection wells constructed for the purpose of injecting fluids produced during oil and gas production, such as brines, and include injection wells used in EOR methods that could be used for the purpose of CO_2 sequestration as part of a CCS project.

Staff is proposing updates to the treatment of direct air capture (DAC) with sequestration projects. In the 2018 rulemaking, the LCFS program made DAC with sequestration eligible for project-based CCS credits. Staff is proposing to limit LCFS credit generation eligibility of DAC with sequestration projects to those located in the United States. This geographic limitation would not apply to DAC-to-fuel applications submitted as Tier 2 alternative fuel pathways, as the final fuels from these pathways must be supplied to California to be eligible for LCFS credits.

2) <u>Compliance Responses</u>

Potential compliance responses to the Proposed Amendments could include the development and construction of CCS projects. These projects could include the modification of existing or new industrial facilities to capture CO_2 emissions, along with construction of new infrastructure such as pipelines, wells, and other surface facilities in various locations to enable the transport and injection of CO_2. The transport distances and pipeline construction requirements for the captured CO_2 would vary considerably, depending on the locations of specific industrial sources. The CCS Protocol, which includes a quantification methodology that accounts for all emitted and sequestered CO_2, ensures that there is a net GHG emissions decrease (i.e., a GHG emissions benefit) for all CCS projects, including CCS projects associated with production of conventional fuels.

F. Summary of Compliance Responses

Reasonably foreseeable compliance responses associated with the Proposed Amendments include the following responses, which could result in changes to the existing physical environment: modifications to cultivation volume and transport of feedstock; changes to location and types of feedstock; new or modified processing facilities for feedstock and finished fuel production; increased transportation of finished alternative fuels to blending terminals or retail fuel sites; construction and operation of new facilities to produce renewable diesel, renewable gasoline, AJF, and renewable propane; construction of biomass gasification and pyrolysis systems for hydrogen and renewable natural gas production; construction of new anaerobic facilities to digest manure from dairies, sewage from wastewater treatment plants, and organic waste diverted from landfills; construction of infrastructure to collect biogas and produce methane; construction of stand-alone and bolt-on cellulosic processing units for renewable fuels production; increase in collection of yard waste or removal of forest litter and agricultural residues; construction of electrolysis units and substitution of renewable natural gas for fossil gas in production of hydrogen; construction of solar and wind electricity generation projects; modification to existing or new industrial facilities to capture CO_2 emissions; construction of new infrastructure such as pipelines, wells and other surface facilities; construction and operation of additional refueling hydrogen stations and EV charging stations; modifications to electricity distribution and transmission infrastructure; modifications to existing crude production facilities to accommodate solar and wind electricity, solar heat, and/or solar steam generation; electrification of equipment and installation of renewable electricity and battery storage systems at petroleum refineries and alternative fuel production facilities; expansion of public transit systems; and land use changes and changes to fuel-associated shipment patterns.

Certain specific amendments included in the Proposed Amendments would not result in compliance responses that change the physical environment or result in adverse environmental effects. These include the addition of third-party verification requirements for additional transaction types, updated modeling tools for pathway application and CI determination, fuel amount reporting improvements, exchange trading, and enhancement to credit transaction reporting. This set of amendments includes modification or updates to already existing programs and processes and would not result in additional physical changes to the environment beyond what would already occur under the current LCFS regulation. Therefore, these specific proposed amendments would have no impact on any of the environmental resource areas analyzed in this Draft EIA and will not be discussed further.

3.0 Impact Analysis and Mitigation Measures

A. Resource Area Impacts and Mitigation Measures

The following discussion provides a programmatic analysis of the reasonably foreseeable compliance responses that could result from implementation of the Proposed Amendments described in Chapter 2.0 of this Recirculated Draft EIA. As discussed above, the revisions and additional information in this Recirculated Draft EIA have not shown any new, substantial environmental impacts, any substantial increases in the severity of an environmental impact, or any alternative or mitigation measure considerably different from those considered in the Draft EIA. Rather, the revisions and additional information have resulted in the addition of substantial new information compared to what was presented in the Draft EIA. Therefore, CARB has determined that recirculation of the project description and the air quality and GHG evaluations is warranted. This section focuses solely on analyzing the impacts related to air quality and GHG emissions, as presented in the Environmental Checklist in Appendix G to the CEQA Guidelines (Title 14 CCR Section 15000 et seq.). If warranted, these impact discussions are followed by the types of mitigation measures that could be required to reduce significant environmental impacts. All other resource areas are analyzed under the Draft EIA circulated on January 2, 2024.

1. Air Quality

Impact 1-1: Short-Term Construction-Related Impacts on Air Quality

Reasonably foreseeable compliance responses associated with the Proposed Amendments include the following responses, which could result in changes to the existing physical environment: modifications to cultivation volume and transport of feedstock; changes to location and types of feedstock; new or modified processing facilities for feedstock and finished fuel production; increased transportation of finished alternative fuels to blending terminals or retail fuel sites; construction and operation of new facilities to produce renewable diesel, renewable gasoline, AJF, and renewable propane; construction of biomass gasification and pyrolysis systems for hydrogen and renewable natural gas production; construction of new anaerobic facilities to digest manure from dairies, sewage from wastewater treatment plants, and organic waste diverted from landfills; construction of infrastructure to collect biogas and produce methane; construction of stand-alone and bolt-on cellulosic processing units for renewable fuels production; increase in collection of yard waste or removal of forest litter and agricultural residues; construction of electrolysis units and substitution of renewable natural gas for fossil gas in production of hydrogen; construction of solar and wind electricity generation projects; modification to existing or new industrial facilities to capture CO_2 emissions; construction of new infrastructure such as pipelines, wells and other surface facilities; construction and operation of additional refueling hydrogen stations and EV charging stations; modifications to electricity distribution and transmission infrastructure; modifications to existing crude production facilities to accommodate solar and wind electricity, solar heat, and/or solar steam generation; electrification of equipment and installation of renewable electricity and battery storage systems at petroleum refineries and alternative fuel production facilities; expansion of public transit systems; and land use changes and changes to fuel-associated shipment patterns.

Implementation of the Proposed Amendments could include construction of new refueling infrastructure or modifications to existing facilities. Any proposed modifications to facilities resulting from any of the Proposed Amendments would require approvals from the applicable local or state land use authority prior to their implementation. Part of the development review and approval process for projects located in California requires environmental review consistent with California environmental laws (e.g., CEQA) and other applicable local requirements (e.g., local air quality district rules and regulations). The environmental review process would include an assessment of whether implementation of such projects could result in short-term construction-related air quality impacts.

At this time, the specific location, type, and number of construction activities are not known and would be dependent upon a variety of factors that are not within the control or authority of CARB and not within its purview. Thus, CARB has not quantified the potential construction-related emission impacts as these would be too speculative to provide a meaningful evaluation. Nonetheless, the analysis presented herein provides a good-faith disclosure of the general types of construction emission impacts that could occur with implementation of these reasonably foreseeable compliance responses. Further, subsequent environmental review would be conducted at such time that an individual project is proposed, and land use or construction approvals are sought.

Generally, it is expected that during the construction phase for any facilities, criteria air pollutants and toxic air contaminants (TAC) could be generated from a variety of activities and emission sources. These emissions would be temporary and occur intermittently depending on the intensity of construction on a given day. Site grading and excavation activities would generate fugitive particulate matter (PM) dust emissions, which is the primary pollutant of concern during construction. Fugitive PM dust emissions (e.g., respirable particulate matter [PM10] and fine particulate matter [PM2.5]) vary as a function of several parameters, such as soil silt content and moisture, wind speed, acreage of disturbance area, and the intensity of activity performed with construction equipment. Exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips could also contribute to short-term increases in PM emissions, but to a lesser extent. It is probable that transport of light equipment and personnel for construction activities would take place using light-duty trucks, while transport of heavy equipment or bulk materials would be hauled in heavy-duty trucks. Exhaust emissions from construction-related mobile sources also include reactive organic gases and oxides of nitrogen (NOx). These emission types and associated levels fluctuate greatly depending on the type, number, and duration of usage for the varying equipment. CARB implements several regulations with the purpose of reducing NOx and PM, and imposing limits on idling from in-use vehicles and equipment, including the Truck and Bus Regulation, the Regulation for In-Use Off-Road Diesel Fueled Fleets, and the Portable Engine Airborne Toxic Control Measure. Much of the equipment used during the construction phase would be subject to these regulations.

The site preparation phase of construction typically generates the most substantial emission levels because of the on-site equipment and ground-disturbing activities associated with grading, compacting, and excavation. Site preparation equipment and activities typically include backhoes, bulldozers, loaders, and excavation equipment (e.g., graders and scrapers). Although detailed construction information is not available at this time, based on the types of activities that could be conducted, it would be expected that the primary sources of construction-related emissions include soil disturbance and equipment related activities (e.g., use of backhoes, bulldozers, excavators, and other related equipment). Based on typical emission rates and other parameters for above mentioned equipment and activities, construction activities could result in hundreds of pounds of daily NO_X and PM emissions (amount generated from two to four pieces of heavy-duty equipment working eight hours per day), which may exceed general mass emissions limits of a local or regional air quality management district depending on the location of the emissions. Thus, implementation of new, or amended, regulations and/or incentives could generate levels that conflict with applicable air quality plans, exceed or contribute substantially to an existing or projected exceedance of state or national ambient air quality standards, or expose sensitive receptors to substantial pollutant concentrations.

As a result, short-term construction-related air quality impacts associated with the Proposed Amendments would be significant.

Potential air quality impacts could be reduced to a less than significant level by mitigation measures prescribed by local, state, federal, or other land use or permitting agencies (either in the U.S. or abroad) with approval authority over the particular development projects. However, because CARB lacks land use authority, mitigation is not within its purview to reduce significant impacts to less-than-significant levels.

Mitigation Measure 1-1

The Regulatory Setting in Attachment A includes applicable laws and regulations that relate to air quality. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or state land use approval and/or permitting authority. New or modified facilities in California would typically qualify as a “project” under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. The following recognized practices are routinely required to avoid and/or minimize impacts on air quality:

- Proponents of new or modified facilities or infrastructure constructed as a result of reasonably foreseeable compliance responses would coordinate with state or local land use agencies to seek entitlements for development including the completion of all necessary environmental review requirements (e.g., CEQA). The local or state land use agency or governing body must follow all applicable local air district thresholds and environmental regulations as part of approval of a project for development.
- Based on the results of the environmental review, proponents shall implement all feasible mitigation to reduce or substantially lessen the potentially significant air quality impacts of the project.
- Project proponents shall apply for, secure, and comply with all appropriate air quality permits and applicable local air district thresholds for project construction from the local agencies with air quality jurisdiction and from other applicable agencies, if appropriate, prior to construction mobilization.

- Project proponents shall comply with the federal Clean Air Act (CAA) and the California Clean Air Act (e.g., New Source Review and Best Available Control Technology criteria), if applicable.
- Project proponents shall comply with local plans, policies, ordinances, rules, local air district thresholds, and regulations regarding air quality-related emissions and associated exposure (e.g., construction-related fugitive PM dust regulations, indirect source review, and payment into off-site mitigation funds).
- For projects located in PM nonattainment areas, project proponents shall prepare and comply with a dust abatement plan that addresses emissions of fugitive dust during construction and operation of the project.

Because the authority to determine project-level impacts and require project-level mitigation lies with land use and/or permitting agencies for individual projects, and the programmatic level of analysis associated with this Draft EIA does not attempt to address project-specific details of mitigation that is beyond CARB’s authority, there is inherent uncertainty in the degree of mitigation that may ultimately be implemented to reduce significant impacts. Although unlikely after implementation of Mitigation Measure 1-1, it is possible that significant impacts on air quality resources could still occur.

Consequently, while impacts could be reduced to a less-than-significant level by land use and/or permitting agency conditions of approval, this Draft EIA takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that short-term construction-related air quality effects resulting from compliance responses associated with the Proposed Amendments would remain **significant and unavoidable**.

Impact 1-2: Long-Term Operational-Related Impacts on Air Quality

Reasonably foreseeable compliance responses associated with the Proposed Amendments include the following responses, which could result in changes to the existing physical environment: modifications to cultivation volume and transport of feedstock; changes to location and types of feedstock; new or modified processing facilities for feedstock and finished fuel production; increased transportation of finished alternative fuels to blending terminals or retail fuel sites; construction and operation of new facilities to produce renewable diesel, renewable gasoline, AJF, and renewable propane; construction of biomass gasification and pyrolysis systems for hydrogen and renewable natural gas production; construction of new anaerobic facilities to digest manure from dairies, sewage from wastewater treatment plants, and organic waste diverted from landfills; construction of infrastructure to collect biogas and produce methane; operation of biogas to biomethane upgrading equipment; construction of stand-alone and bolt-on cellulosic processing units for renewable fuels production; increase in collection of yard waste or removal of forest litter and agricultural residues; construction of electrolysis units and substitution of renewable natural gas for fossil gas in production of hydrogen; construction of solar and wind electricity generation projects; modification to existing or new industrial facilities to capture CO_2 emissions; construction of new infrastructure such as pipelines, wells and other surface facilities; construction and operation of additional refueling hydrogen stations and EV charging stations; modifications to electricity distribution and transmission infrastructure; modifications to existing crude production facilities to accommodate solar and wind electricity, solar heat, and/or solar steam generation; electrification of equipment and installation of renewable electricity and battery storage systems at petroleum refineries and alternative fuel production facilities; expansion of public transit systems; and land use changes and changes to fuel-associated shipment patterns.

The potential substitution from fossil fuels to low-CI electricity, hydrogen, natural gas, and liquid biofuels associated with the Proposed Amendments may result in reductions in criteria pollutants and air toxics. Life cycle analyses of these alternative fuels (from production through their use as transportation fuel) shows that they have a lower carbon intensity and thus emit fewer GHGs on a lifecycle basis than fossil fuels like gasoline, diesel, and fossil jet fuel. The air quality analysis conducted for the Proposed Amendments shows that deployment of alternative fuels will also reduce criteria pollutants and toxics relative to continued use of fossil fuels like gasoline, diesel and fossil jet fuel.[47,48] The program incentivizes these low and zero-CI fuels through the declining annual CI benchmark while also incentivizing direct emission reductions through facility operational changes and carbon capture and sequestration projects.

Biomass-based diesel use attributed to the LCFS as part of the Proposed Amendments could result in an overall potential decrease in long-term operational NOx and PM emissions relative to use of conventional diesel in all state-designated and federally designated ozone non-attainment areas from 2024 through 2046. There is also a projected increase in both long-term operational NOx and PM2.5 emissions due to biomass and biofuel transportation and distribution as a result of the Proposed Amendments, but these emission increases are much less than the emission benefits provided by the use of biomass-based diesel that would be incentivized by the Proposed Amendments. Additionally, it is expected that the Proposed Amendments could result in an increase in production and/or expansion at California alternative fuel facilities and modification of alternative fuel facilities to accommodate carbon capture and storage projects. Finally, the Proposed Amendments are expected to result in an increase in the use of alternative jet fuel (AJF) at California airports. There are projected reductions in long-term operational criteria pollutant emissions from the use of AJF due to reduced criteria pollutant emissions during taxi, takeoffs, and landings, which may result in decreased detrimental health impacts, especially near airports. Overall, the Proposed Amendments are expected to result in lower total long-term operational NOx and PM2.5 emissions in each year from 2024 through 2046.

Air quality changes from the Proposed Amendments differ geographically based on fuel production and consumption patterns. The Proposed Amendments are expected to reduce criteria pollutants and toxics more significantly in regions with heavy use of motor vehicles and diesel engines, such as big population centers (e.g., South Coast) and areas with heavy truck use (e.g., San Joaquin Valley). Statewide, implementation of the Proposed Amendments could reduce health impacts in all the

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[47] Fossil fuels contain benzene, toluene, ethyl benzene, and xylenes (BTEX compounds), which can be emitted into the air and contaminate soil and water. Gasoline engine exhaust contains benzene, 1,3-butadiene, formaldehyde, and acetaldehyde. Diesel engine exhaust contains diesel particulate matter, which is a toxic air contaminant (TAC). Generally, all exhaust from the combustion of hydrocarbon fuels contains benzene as a product of incomplete combustion.
[48] Criteria pollutants are estimated using a variety of tools including CARB's California Emissions Projection Analysis Model (CEPAM) 2019 Ozone SIP v.1.04, the on-road vehicle emission inventory tool EMFAC2021 v.1.02, CA-GREET 3.0, and CEIDARS 2020 Static.

categories evaluated by CARB for the Health Impact Analysis.[49] These reductions in adverse health cases would be seen across all ages in the State and could particularly benefit children due to reduced cases of asthma onset and symptoms.

Reducing criteria pollutants and toxic emissions from fuel combustion in line with California's air quality goals requires deploying ZEVs and ensuring the availability of fueling infrastructure to support ZEV deployment. CARB staff estimated air quality benefits attributable to the Proposed Amendments. In projecting the emissions benefits of the Proposed Amendments, CARB staff referenced the information contained in Appendix C-1, pages B-1 through B-12, including Tables 47-59 and the accompanying narrative.[50] The emissions analysis includes expected reductions in emissions from upstream oil and gas extraction that would be expected to result from corresponding petroleum fuel demand reductions. These emission reductions also include estimated changes in emissions that occur from changes in renewable fuel use in vehicles, feedstock transport, and changes in renewable fuel production. Additionally, the emissions benefits modeled for the Proposed Amendments were calculated using a baseline that includes technology changes expected from implementation of the on-road light duty (Advanced Clean Cars II) and on-road heavy duty (Advanced Clean Trucks and Advanced Clean Fleets) regulations and is therefore a conservative analysis that does not reflect the benefits of transitioning to ZEV. However, while not quantified, the Proposed Amendments are expected to play a key role in supporting implementation of these vehicle-focused regulations, by reducing the cost of electricity and hydrogen used as vehicle fuels, supporting installation and operation of charging and hydrogen refueling stations, and promoting investment in transportation electrification in disadvantaged, low-income and rural communities. Therefore, the LCFS program remains a key tool in supporting the transition to ZEV technology and the concurrent air quality and GHG benefits.

The Proposed Amendments achieve reductions of PM2.5 and NOx through 2046.[51] These emissions reductions are driven in part by increased use of renewable diesel and alternative jet fuel, which displace fossil diesel and fossil jet fuel. Relative to the air quality calculations underlying the Staff Report, staff has updated the emission factor for NOx and PM benefits from alternative jet fuel. The updated emission factor attributes no NOx benefits to alternative jet fuel, but more PM benefits (changed from 45% to 65% reduction compared to fossil jet fuel).[52] In addition to LCFS support of alternative jet fuel deployment, CARB is also working with local, Federal, and international agencies to pursue criteria and GHG emission reductions from airports and aircraft.[53] As noted earlier,

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[49] California Air Resources Board, *Low Carbon Fuel Standard 2023 Amendments Standardized Regulatory Impact Assessment (SRIA): Chapter 2*. September 8, 2023. *https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf*

[50] Staff identified a small technical error in the energy density of biodiesel and renewable diesel used for the analysis shown in Appendix C-1, and corrected the error for the updated ISOR emissions analysis.

[51] California Air Resources Board, *California's Air Quality Analysis Workbook from 15-Day Package*, July 19, 2024. https://ww2.arb.ca.gov/resources/documents/supplemental-20232024-lcfs-modeling-documentation

[52] Hamilton et al, "Alternative Jet Fuels Emissions: Quantification Methods Creation and Validation Report," Transportation Research Board, Airport Cooperative Research Program, August 2019.

[53] California Air Resources Board, *California's Actions in Reducing Emissions from Airports and Aircraft*, July 19, 2024. https://ww2.arb.ca.gov/sites/default/files/2024-08/California%20Aircraft%20and%20Airports%20Fact%20Sheet%20-%20July%202024_0.pdf

emissions reductions from phasing down oil extraction and refining operations in tandem with petroleum demand reductions are also included in this analysis. In total, the Proposed Amendments achieve reductions of 9,232 tons of PM2.5 and 35,161 tons of NOx in aggregate through 2046.

Table 3: Criteria Pollutant Emissions per Day Compared To Business As Usual Scenario

Year	NOx (tpd)	PM2.5 (tpd)
2024	-1.8	-0.3
2025	-4.8	-0.7
2026	-5.5	-0.9
2027	-5.2	-1.0
2028	-4.8	-1.0
2029	-4.8	-1.0
2030	-5.1	-1.1
2031	-5.0	-1.1
2032	-4.8	-1.1
2033	-4.6	-1.1
2034	-4.4	-1.1
2035	-4.3	-1.1
2036	-4.2	-1.1
2037	-4.0	-1.1
2038	-3.8	-1.1

Year	NOx (tpd)	PM2.5 (tpd)
2039	-3.8	-1.2
2040	-3.8	-1.2
2041	-3.8	-1.2
2042	-3.6	-1.2
2043	-3.6	-1.3
2044	-3.5	-1.3
2045	-3.5	-1.4
2046	-3.5	-1.4
Total	-96.3	-25.3

Table 4: Annual PM2.5 Emissions by Air Basin (tpd)[54,55]

Air Basin	Great Basin Valleys	Lake County	Lake Tahoe	Mojave Desert	Mountain Counties	North Central Coast	North Coast	Northeast Plateau	Sacrame-nto Valley	Salton Sea	San Diego	San Francisco Bay Area	San Joaquin Valley	South Central Coast	South Coast
Year	tons/day	tons/ day	tons/ day	tons/ day	tons/day	tons/day	tons/ day	tons/day	tons/day	tons/day	tons/day	tons/day	tons/day	tons/day	tons/ day
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1
2025	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	-0.1	-0.1	0.0	-0.2
2026	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.1	-0.1	0.0	-0.2
2027	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.3	0.0	-0.2
2028	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.2	0.0	-0.2
2029	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.3	0.0	-0.2
2030	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.3	0.0	-0.2
2031	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2032	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2033	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2034	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2035	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2036	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2037	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2038	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2039	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.4	0.0	-0.2
2040	0.0	0.0	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.4	-0.1	-0.2

54 Numbers rounded to tenth place.
55 California Air Resources Board, *California's Air Quality Analysis Workbook from 15-Day Package*, July 19, 2024. https://ww2.arb.ca.gov/resources/documents/supplemental-20232024-lcfs-modeling-documentation

Air Basin	Great Basin Valleys	Lake County	Lake Tahoe	Mojave Desert	Mountain Counties	North Central Coast	North Coast	Northeast Plateau	Sacrame-nto Valley	Salton Sea	San Diego	San Francisco Bay Area	San Joaquin Valley	South Central Coast	South Coast
2041	0.0	0.0	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.4	-0.1	-0.2
2042	0.0	0.0	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.4	-0.1	-0.2
2043	0.0	0.0	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.4	-0.1	-0.2
2044	0.0	0.0	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.5	-0.1	-0.2
2045	0.0	0.0	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.5	-0.1	-0.2
2046	0.0	0.0	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.5	-0.1	-0.2

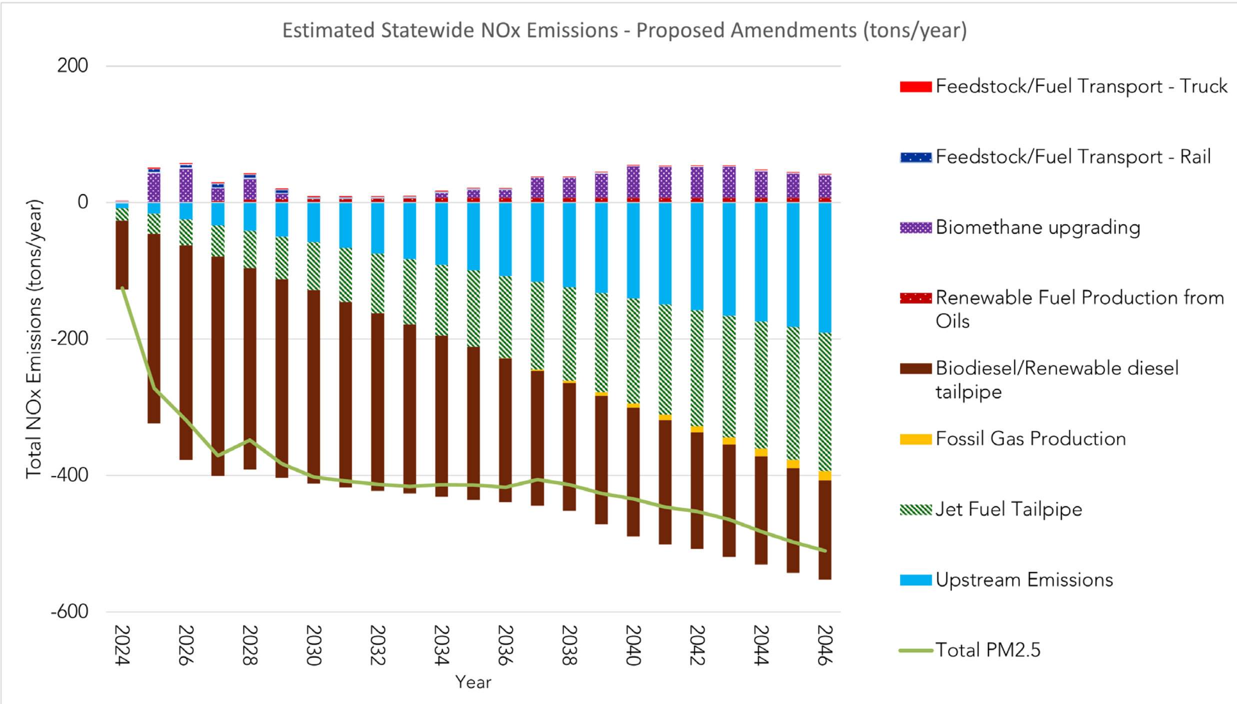
Table 5: Annual NOx Emissions by Air Basin (tpd)[56,57]

Air Basin	Great Basin Valleys	Lake County	Lake Tahoe	Mojave Desert	Mountain Counties	North Central Coast	North Coast	Northeast Plateau	Sacrame-nto Valley	Salton Sea	San Diego	San Francisco Bay Area	San Joaquin Valley	South Central Coast	South Coast
Year	tons/day	tons/ day	tons/ day	tons/day	tons/day	tons/day	tons/ day	tons/day	tons/day	tons/ day	tons/ day	tons/day	tons/day	tons/day	tons/ day
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-0.5	-0.1	-0.5
2025	0.0	0.0	0.0	-0.3	0.0	-0.1	-0.1	-0.1	-0.4	-0.2	-0.3	-0.6	-1.2	-0.2	-1.4
2026	0.0	0.0	0.0	-0.4	0.0	-0.1	-0.1	-0.1	-0.5	-0.2	-0.3	-0.7	-1.3	-0.2	-1.6
2027	0.0	0.0	0.0	-0.4	0.0	-0.1	-0.1	-0.1	-0.4	-0.2	-0.3	-0.6	-1.3	-0.2	-1.5
2028	0.0	0.0	0.0	-0.4	0.0	-0.1	-0.1	-0.1	-0.4	-0.2	-0.3	-0.6	-1.2	-0.2	-1.3
2029	0.0	0.0	0.0	-0.4	0.0	-0.1	-0.1	-0.1	-0.4	-0.2	-0.2	-0.5	-1.3	-0.2	-1.3
2030	0.0	0.0	0.0	-0.5	0.0	-0.1	-0.1	-0.1	-0.4	-0.2	-0.2	-0.5	-1.4	-0.2	-1.3
2031	0.0	0.0	0.0	-0.5	0.0	-0.1	-0.1	-0.1	-0.4	-0.2	-0.2	-0.5	-1.4	-0.2	-1.3
2032	0.0	0.0	0.0	-0.5	0.0	-0.1	-0.1	0.0	-0.4	-0.2	-0.2	-0.5	-1.4	-0.2	-1.2

56 Numbers rounded to tenth place.
57 California Air Resources Board, *California's Air Quality Analysis Workbook from 15-Day Package*, July 19, 2024. https://ww2.arb.ca.gov/resources/documents/supplemental-20232024-lcfs-modeling-documentation

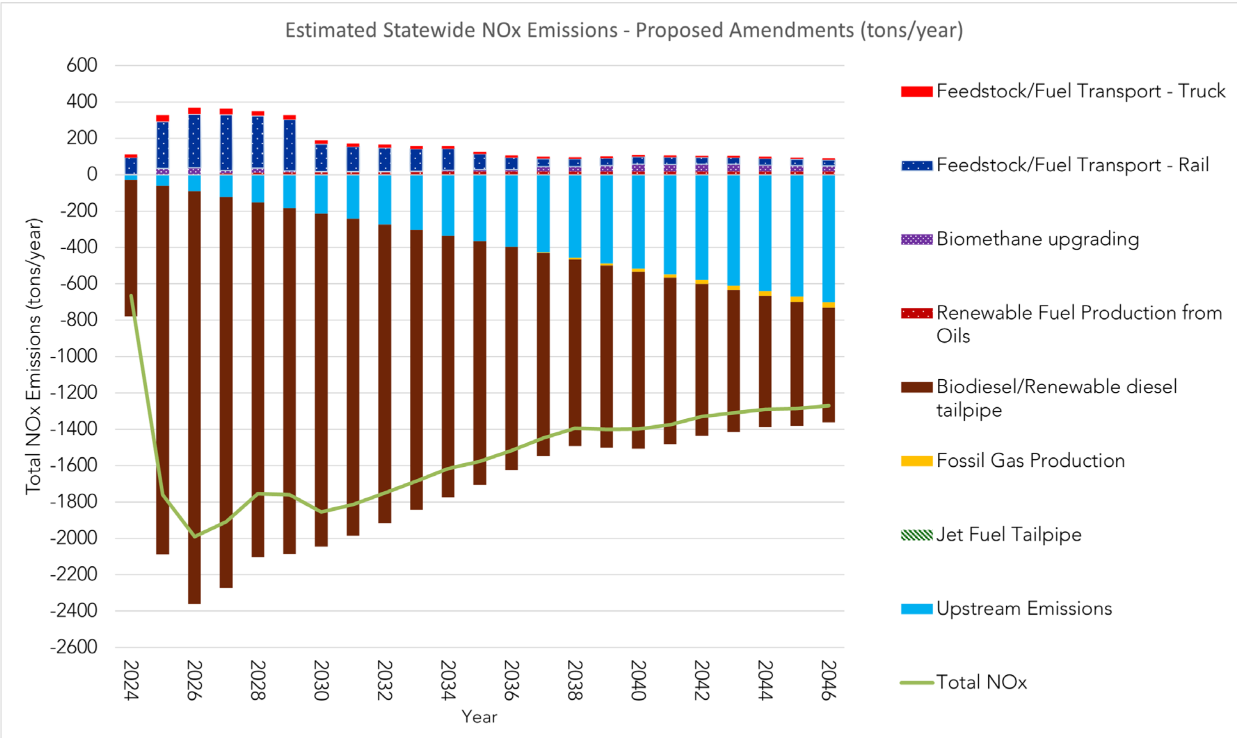
Air Basin	Great Basin Valleys	Lake County	Lake Tahoe	Mojave Desert	Mountain Counties	North Central Coast	North Coast	Northeast Plateau	Sacrame-nto Valley	Salton Sea	San Diego	San Francisco Bay Area	San Joaquin Valley	South Central Coast	South Coast
2033	0.0	0.0	0.0	-0.5	0.0	-0.1	-0.1	0.0	-0.4	-0.2	-0.2	-0.4	-1.4	-0.2	-1.1
2034	0.0	0.0	0.0	-0.5	0.0	-0.1	-0.1	0.0	-0.3	-0.2	-0.2	-0.4	-1.3	-0.2	-1.1
2035	0.0	0.0	0.0	-0.5	0.0	-0.1	-0.1	0.0	-0.3	-0.2	-0.2	-0.4	-1.3	-0.2	-1.0
2036	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.3	-0.2	-0.2	-0.3	-1.3	-0.2	-0.9
2037	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.3	-0.1	-0.1	-0.3	-1.3	-0.2	-0.9
2038	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.3	-0.1	-0.1	-0.3	-1.3	-0.2	-0.8
2039	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.3	-0.1	-0.1	-0.3	-1.3	-0.2	-0.8
2040	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.3	-0.1	-0.1	-0.3	-1.3	-0.2	-0.8
2041	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-1.3	-0.2	-0.7
2042	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-1.3	-0.3	-0.7
2043	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-1.3	-0.3	-0.7
2044	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-1.3	-0.3	-0.6
2045	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-1.4	-0.3	-0.6
2046	0.0	0.0	0.0	-0.5	0.0	-0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-1.4	-0.3	-0.6

Figure 5: Estimated Statewide PM2.5 Emissions Impact of the Proposed Amendments (tons/year)[58]



[58] California Air Resources Board. *"15-day Proposed Air Quality Emissions Calculation"*. August 12, 2024. Excel Spreadsheet. https://ww2.arb.ca.gov/sites/default/files/2024-08/2024%20LCFS_Amendments_Air_Quality_Calculations_15Day%20Proposed_1.xlsx

Figure 6: Estimated Statewide NOx Emissions Impact of the Proposed Amendments (tons/year)[59]



As discussed previously, the Proposed Amendments would result in shifting fuel production activities and the establishment of new fuel production. This production or combustion of individual alternative fuels in specific applications may result in criteria

[59] Ibid.

pollutant and other emissions.[60,61,62] These potential local increases in emissions would be largely dependent on the extent and location of increased biofuel production. See Appendix C-1 of the ISOR for more information on individual fuel production, transport, and use emission factors. While CARB anticipates some potential increases in local emissions associated with increased biofuel production and transport and biomethane production, on an air basin level, CARB does not believe significant localized increases are likely since these increases would likely be equivalent to or less than emission reductions associated with biodiesel, renewable diesel, and alternative jet fuel use. Overall, while CARB anticipates beneficial long-term air quality regional and statewide impacts associated with the Proposed Amendments, an increase in emissions of criteria pollutants associated with feedstock transport to production facilities, production of biofuels, and transport of finished fuels to blending facilities is possible. Any new biofuel production facilities would be required to follow all State and local emission-related requirements and standards to protect public health and the environment. Moreover, on a statewide and regional basis, potential emission increases near production facilities are estimated to be very small relative to total emission reductions from the use of biodiesel and renewable diesel, alternative jet fuel, refinery efficiency projects, and solar steam in those same areas. CARB also expects that implementation of recent vehicles regulations (e.g., Advanced Clean Fleets, Advanced Clean Trucks, and Advanced Clean Cars II) will result in significant localized and statewide emission reductions as combustion emissions decline. However, in response to the LCFS amendments, small emissions increases may occur near feedstock and finished fuel transportation routes and near production facilities. Emissions from these stationary sources would be monitored and controlled by local air districts to minimize the negative impacts from the increased production. Under State Implementation Plans (SIPs), states are required to provide comprehensive plans to attain the NAAQS set by the U.S. EPA. CARB reviews and approves local area districts and other agencies' SIP elements and ensures they achieve the State's criteria pollution targets. Additionally, AB 617 directs CARB to

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[55] For example, in the Environmental Analysis for the 2018 LCFS Rulemaking, CARB staff identified that biodiesel combustion use may contribute to increased NOx emissions relative to conventional diesel in specific vehicle applications. CARB implements the Regulation on Commercialization of Alternative Diesel Fuels (title 13, CCR, §§ 2293 et seq.) to ensure NOx emissions equivalence from biodiesel use. CARB staff used the same conservative approach included in the 2018 rulemaking to estimate NOx biodiesel emissions as part of this rulemaking and have continued to study the potential emissions impacts of biodiesel and other fuels in California and refine approaches to controlling such potential impacts based on available evidence.

[56] California Air Resources Board, *Low Emission Diesel (LED) Study: Biodiesel and Renewable Diesel* Emissions *in Legacy and New Technology Diesel Engines*, November 2021. https://ww2.arb.ca.gov/sites/default/files/2021-12/Low_Emission_Diesel_Study_Final_Report_12-29-21.pdf

[57] Another example is that the upgrading of biogas and use of biomethane may result in emissions, depending on the biogas source, collection process, upgrading process, and end-use. CARB staff estimated criteria pollutant emissions from biogas and biomethane utilization as part of this rulemaking and continues to study the potential emissions impacts of biogas and biomethane and refine approaches to controlling such potential impacts based on available evidence.

cooperate with local air districts to implement criteria pollutant reduction programs in high-exposure communities. AB 617 additionally requires CARB to establish and maintain a database of the best-available retrofit control technology for criteria pollutants. The programs, standards, and plans specified under the SIPs and AB 617 will most likely ensure that any increase in criteria pollutant emissions from increased activity due to the Proposed Amendments will be controlled to minimize the impacts on California residents, especially in areas with poor air quality.

Notwithstanding the efforts of CARB and local air districts discussed above to monitor and reduce criteria pollutant emissions, and despite estimated beneficial long-term operational impacts statewide, localized increases in emissions because of the Proposed Amendments could occur near biofuel production facilities and routes for biofuel feedstock and finished fuel transportation. These potential local increases in emissions would be largely dependent on the extent and location of increased biofuel production. Because the LCFS does not specify the specific sites at which alternative fuels are produced, both the extent of increased biofuel production and the location of potential new biofuel facilities cannot be known at this time and would be too speculative to quantify.

As discussed above, CARB does not believe significant localized increases are likely, and anticipates overall beneficial long-term operational impacts statewide. Nevertheless, in an abundance of caution and for the purposes of complete public disclosure, CARB concludes that long-term local air quality impacts associated with the Proposed Amendments could be potentially significant and unavoidable.

Mitigation Measure 1-2

The Regulatory Setting in Attachment A includes applicable laws and regulations that relate to air quality. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or state land use approval and/or permitting authority. New or modified facilities in California would typically qualify as a “project” under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. The following recognized practices are routinely required to avoid and/or minimize impacts on air quality:

- Proponents of new or modified facilities constructed and operated as a result of reasonably foreseeable compliance responses would coordinate with local or State land use agencies to seek entitlements for development including the completion of all necessary environmental review requirements (e.g., CEQA). The local jurisdiction with land use authority would determine that the environmental review process complied with CEQA and other applicable regulations, prior to project approval.

- Based on the results of the environmental review, proponents would implement all feasible mitigation identified in the environmental document to reduce or substantially lessen the operational-related air quality impacts of the project.
- Project proponents would apply for, secure, and comply with all appropriate air quality permits for project operation from the local agencies with air quality jurisdiction and from other applicable agencies, if appropriate, prior to commencement of project operation.
- Project proponents would comply with the federal Clean Air Act and the California Clean Air Act (e.g., New Source Review and Best Available Control Technology criteria, if applicable).
- Project proponents would comply with local plans, policies, ordinances, rules, and regulations regarding air quality-related emissions and associated exposure (e.g., indirect source review, and payment into offsite mitigation funds).
- For projects located in PM nonattainment areas, prepare and comply with a dust abatement plan that addresses emissions of fugitive dust during operation of the project.

Because the authority to determine project-level impacts and require project-level mitigation lies with land use and/or permitting agencies for individual projects, and the programmatic level of analysis associated with this Draft EIA does not attempt to address project-specific details of mitigation, there is inherent uncertainty in the degree of mitigation that may ultimately be implemented to reduce significant impacts. Although unlikely after implementation of Mitigation Measure 1-2, it is possible that significant impacts on air quality resources could still occur.

Consequently, while CARB does not believe significant localized increases are likely and anticipates overall beneficial long-term operational impacts and if they were to exist impacts should be reduced to a less than significant level by land use and/or permitting agency conditions of approval, this EIA takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that long-term operational-related air quality impacts resulting from the operation of new or modified facilities associated with the Proposed Amendments would remain **significant and unavoidable**.

Impact 1-3: Short-Term Construction-Related and Long-Term Operational Impacts from Odors

Reasonably foreseeable compliance responses associated with the Proposed Amendments include the following responses, which could result in changes to the existing physical environment: modifications to cultivation volume and transport of feedstock; changes to location and types of feedstock; new or modified processing facilities for feedstock and finished fuel production; increased transportation of finished alternative fuels to blending terminals or retail fuel sites; construction and operation of new facilities to produce renewable diesel, renewable gasoline, AJF, and renewable propane; construction of biomass gasification and pyrolysis systems for hydrogen and renewable natural gas production; construction of new anaerobic facilities to digest manure from dairies, sewage from wastewater treatment plants, and organic waste diverted from landfills; construction of infrastructure to collect biogas and produce methane; construction of stand-alone and bolt-on cellulosic processing units for renewable fuels production; increase in collection of yard waste or removal of forest litter and agricultural residues; construction of electrolysis units and substitution of renewable natural gas for fossil gas in production of hydrogen; construction of solar and wind electricity generation projects; modification to existing or new industrial facilities to capture CO_2 emissions; construction of new infrastructure such as pipelines, wells and other surface facilities; construction and operation of additional refueling hydrogen stations and EV charging stations; modifications to electricity distribution and transmission infrastructure; modifications to existing crude production facilities to accommodate solar and wind electricity, solar heat, and/or solar steam generation; electrification of equipment and installation of renewable electricity and battery storage systems at petroleum refineries and alternative fuel production facilities; expansion of public transit systems; and land use changes and changes to fuel-associated shipment patterns.

Although it is reasonably foreseeable that construction activities could occur, there is uncertainty as to the exact location of any new facilities or modification of existing facilities. Typically, such facilities would be located in industrial or rural areas with appropriate zoning to accommodate these specific activities. Short-term construction activities could generate short-term odors associated with operation of diesel equipment; however, such activities would be short-term in nature and would not be expected to adversely affect long-term air quality.

With respect to long-term operational impacts associated with odors, new facilities and equipment constructed as a result of the Proposed Amendments would not add to odors but could help reduce existing odors at the sites. Implementation of the Proposed Amendments would incentivize the collection and use of biomethane gas from dairies, landfills, and wastewater treatment plants. The release of methane gas from these sites is usually accompanied by odorous compounds (e.g., ammonia and hydrogen sulfide). Generally, odor is considered a perceived nuisance and an environmental impact. Factors that would affect odor impacts include the design of collection facilities and exposure duration. Methane gas collection systems at landfills would involve wells for extraction of landfill methane produced from decomposing waste, and wastewater treatment plants would modify existing digesters in enclosed operations. Wastewater treatment plants also typically maintain odor control systems to address fugitive emissions at existing facilities. Manure management at dairies typically involves flushing and/or scraping manure into on-site storage ponds or stockpiles. Manure in these storage ponds and stockpiles naturally undergo decomposition, and as a result, odorous compounds are released into the environment.

However, the implementation of new digester facilities at existing livestock operations would result in the manure being placed into the digester rather than into on-site storage ponds or stockpiles, potentially reducing odors that would otherwise occur without the new digester facilities. This would limit open air degradation (resulting in the breakdown of volatile organic compounds through anaerobic processes that would occur in the closed system) and would result in more control over the exhaust emissions. While digesters constructed for manure would perform anaerobic digestion in a closed system, emissions of odorous compounds could still be released into the environment from the overall site. While digesters typically result in more control over facility odor emissions, fugitive emissions of odorous compounds could be offensive to sensitive receptors, depending on their proximity, the design of anaerobic digesters, and exposure duration. Thus, short-term construction-related odor impacts and long-term operational odor impacts associated with the Proposed Amendments would be **less than significant**.

2. Greenhouse Gas Emissions

Impact 2-1: Short-Term Construction-Related and Long-Term Operational-Related Impacts to Greenhouse Gas Emissions

Reasonably foreseeable compliance responses associated with the Proposed Amendments include the following responses, which could result in changes to the existing physical environment: modifications to cultivation volume and transport of feedstock; changes to location and types of feedstock; new or modified processing facilities for feedstock and finished fuel production; increased transportation of finished alternative fuels to blending terminals or retail fuel sites; construction and operation of new facilities to produce renewable diesel, renewable gasoline, AJF, and renewable propane; construction of biomass gasification and pyrolysis systems for hydrogen and renewable natural gas production; construction of new anaerobic facilities to digest manure from dairies, sewage from wastewater treatment plants, and organic waste diverted from landfills; construction of infrastructure to collect biogas and produce methane; construction of stand-alone and bolt-on cellulosic processing units for renewable fuels production; increase in collection of yard waste or removal of forest litter and agricultural residues; construction of electrolysis units and substitution of renewable natural gas for fossil gas in production of hydrogen; construction of solar and wind electricity generation projects; modification to existing or new industrial facilities to capture CO_2 emissions; construction of new infrastructure such as pipelines, wells and other surface facilities; construction and operation of additional refueling hydrogen stations and EV charging stations; modifications to electricity distribution and transmission infrastructure; modifications to existing crude production facilities to accommodate solar and wind electricity, solar heat, and/or solar steam generation; electrification of equipment and installation of renewable electricity and battery storage systems at petroleum refineries and alternative fuel production facilities; expansion of public transit systems; and land use changes and changes to fuel-associated shipment patterns.

Construction of facilities would require use of vehicles and equipment that would consume fuel and emit GHGs for construction activities, materials transport, and worker commutes. Construction-related GHG emissions would be temporary and last only for the duration of construction. Local agencies, such as air pollution control districts, are generally charged with determining acceptable thresholds of GHG emissions, measured in metric tons of carbon dioxide equivalent ($MTCO_2e$) per year. Quantification of short-term construction-related GHG emissions is generally based on a combination of methods, including the use of exhaust emission rates from emissions models, such as the California Emissions Estimator Model (CalEEMod), OFFROAD 2007, and CARB's California's EMissionsFACtor (EMFAC) models. These models require consideration of assumptions, including construction timelines and energy demands (i.e., fuel and electricity).

Air districts differ in their treatment of construction emissions. For instance, the Sacramento Metropolitan Air Quality Management District recommends that construction emissions be compared to a bright-line threshold of significance of 1,100 $MTCO_2e$ per year.[63] The Placer County Air Pollution Control District recommends that the significance of a project's construction emissions be compared to a 10,000 $MTCO_2e$ per year mass emissions threshold.[64] By contrast, the Bay Area Air Quality Management District (BAAQMD), does not recommend a numerical threshold for assessing the significance of construction-generated GHG emissions.[65] Additionally, other air districts, such as the South Coast Air Quality Management District, recommend amortizing construction emissions over a 30-year period and adding these emissions to total operational emissions.[66] This indicates that there is no consistent threshold uniformly applied across the State; therefore, depending on a project's location, the significance of construction-generated GHGs may be determined significant or less than significant depending on the threshold applied at the project level. Establishing a threshold of significance is also the discretion of a lead agency, which may develop an approach with substantial evidence.

Given that the potential compliance responses that would occur from implementation of the Proposed Amendments would occur statewide, no exact location of these compliance responses can be determined at this time. Also, in consideration of the

[63] Sacramento Metropolitan Air Quality Management District, *Chapter 6, "Greenhouse Gas Emissions*." In CEQA Guide. 2021. *https://www.airquality.org/LandUseTransportation/Documents/Ch6GHG2-26-2021.pdf*

[64] Placer County Air Pollution Control District, *Chapter 2, "Thresholds of Significance*." In 2017 Air Quality Handbook. 2017. *https://www.placerair.org/DocumentCenter/View/2047/Chapter-2-Thresholds-of-Significance-PDF*

[65] Bay Area Air Quality Management District, *Chapter 6, "Project-Level Climate Impacts*." In CEQA Air Quality Guidelines. 2022. *https://www.baaqmd.gov/~/media/files/planning-and-research/ceqa/ceqa-guidelines-2022/ceqa-guidelines-chapter-6-project-climate-impacts_final-pdf.pdf?la=en*

[66] South Coast Air Quality Management District, *Draft Guidance Document – Interim CEQA Greenhouse Gas Significance Threshold*. October 2008. *https://www.aqmd.gov/docs/default-source/ceqa/handbook/greenhouse-gases-(ghg)-ceqa-significance-thresholds/ghgattachmente.pdf*

multiple thresholds that could be applied for project-level analyses, CARB cannot assure the significance of a future project's construction emissions. Moreover, construction GHG emissions can be contextualized in consideration of long-term GHG emissions. For instance, in its 2022 Justification Report for its *2022 Air Quality Guide,* BAAQMD states that "greenhouse gas emissions from construction represent a very small portion of a project's lifetime GHG emissions" and therefore, as stated above, does not recommend a numerical or qualitative threshold for determining the significance of construction-generated GHG emissions.[67] BAAQMD, instead, uses a qualitative approach using project design features that inherently reduce operational GHG emissions, which is sufficient to offset the temporary GHG emissions emitted during a project's construction.

Similarly, as indicated in CARB's GHG analysis of the Proposed Amendments, while some small level of GHG emissions would be emitted from the reasonably foreseeable compliance responses to the Proposed Amendments, these emissions would be substantially less than the emissions benefits of implementation of the Proposed Amendments.[68]

The Proposed Amendments include strengthening the CI reduction benchmarks through 2030 in support of achieving California's 2045 GHG reduction requirement enacted through SB 1279. The required reduction in the CI of the transportation fuel pool is expected to result in annual GHG emissions reductions as shown in Figure 7. The LCFS calculates emission reductions on a full life cycle basis for the fuel production, transport, and use; therefore, GHG emission reductions occur both in California and out-of-state. Staff calculated GHGs associated with each scenario.

Figure 7 summarizes the annual life cycle GHG emissions reductions under the business as usual (BAU) scenario and the proposed amendments scenario. Staff expects the proposed amendments to reduce GHG emissions relative to the BAU by 554 million metric tons in carbon dioxide equivalent ($MMTCO_2e$) from 2024 through 2046.[69] GHG reduction estimates are derived from the California Transportation Supply

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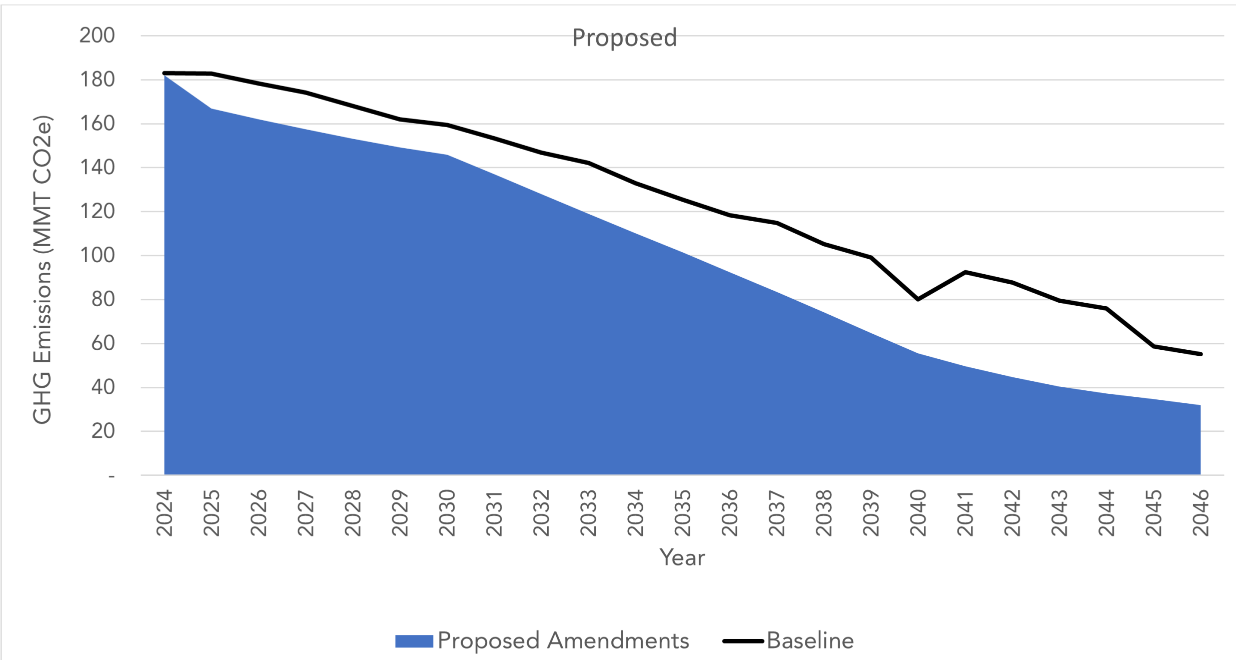
[67] Bay Area Air Quality Management District, Appendix B, *CEQA Thresholds for Evaluating the Significance of Climate Impacts from Land Use Projects and Plans*. California Environmental Quality Act Air Quality Guidelines. April 2022. *https://www.baaqmd.gov/~/media/files/planning-and-research/ceqa/ceqa-guidelines-2022/appendix-b-thresholds-for-evaluating-significance-of-climate-impacts_final-pdf.pdf?la=en*

[68] For supporting data and analysis supporting CARB's calculations of GHG emission reductions, see the Greenhouse Gas Emissions Analysis Workbook for the 15-day Changes. August 12, 2024. https://ww2.arb.ca.gov/sites/default/files/2024-08/15Day%20GHG%20Calculations_posted_0.xlsx.

[69] For supporting data and analysis supporting CARB's calculations of GHG emission reductions, see the Greenhouse Gas Emissions Analysis Workbook for the 15-day Changes (Aug. 12, 2024). https://ww2.arb.ca.gov/sites/default/files/2024-08/15Day%20GHG%20Calculations_posted_0.xlsx.

(CATS)[70] outputs of the fuel quantities and average annual CI associated with each fuel based on the Proposed Amendments, and expected GHG reductions associated with expected reductions in emissions from upstream oil and gas extraction that would be expected to result from corresponding petroleum fuel demand reductions. Staff used the same assumptions and framework for calculating upstream GHG emission reductions used to calculate upstream air quality reductions, but referenced 2019 oil and gas extraction GHG emissions from the Scoping Plan as the baseline value in the calculation.[71]

Figure 7: Annual GHG Emissions of Business as Usual and Proposed Amendments[72]



The comparatively small level of GHG emissions related to construction and operation of facilities associated with the compliance responses, as described above, would be offset by the reductions in GHG emissions from the implementation of the Proposed

[70] For more information and context on the CATS model, please see Attachment C: LCFS Fuels and Credit Market Modeling for the 15-day Changes. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/15day_attc.pdf
[71] See California Air Resources Board, *Appendix C-1: Standardized Regulatory Impact Assessment (SRIA).* September 9, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appc-1.pdf for further information on the upstream oil emission reduction methodology.
[72] California Air Resources Board. *Greenhouse Gas Emissions Analysis Workbook for 15-Day Change*s. August 12, 2024. https://ww2.arb.ca.gov/sites/default/files/2024-08/15Day%20GHG%20Calculations_posted_0.xlsx.

Amendments. As a result, implementation of the proposed strategy would result in a **beneficial** impact on GHG emissions.