CALIFORNIA TRANSPORTION SUPPLY MODEL DOCUMENTATION

Last Modified: August 2023

California Transportation Supply (CATS) Model v0.2 – Technical Documentation for August 2023 Example Scenario

CALIFORNIA
TRANSPORTATION
SUPPLY
MODEL (CATS)

Contents

Introduction

The California Transportation Supply Model (CATS) is an optimization model developed by the California Air Resources Board (CARB) to help estimate fuel supply that may be delivered to California given a set of policy and technology considerations. This document details the model formulation and underlying data assumptions that CARB has used to build an example scenario that can be run in the model.

Modeling Overview

CATS is coded in Python 3.9 and uses the Google linear programming optimization solver (GLOP) from the OR-Tools package to solve the defined optimization problem.[1] To determine fuel mixes likely available for California, CATS seeks to minimize the cost of supplying all defined fuel pools such that fuel demand constraints are met. Feedstock variables are created for all fuel conversion pathways and feedstock pairs for each feedstock price point.

Equation 1 shows the objective function for the model, in which costs for converting Feedstock (FS) for a given feedstock-to-fuel conversion technology (t), at a feedstock price (p) and total conversion cost (C_t) is minimized. Fuel produced from a specific feedstock must not exceed the availability of that feedstock at a given price, as specified in Equation 2. The total amount of fuel produced, at a specified yield (γ_t), through different production pathways must satisfy total demand (D) for a given fuel pool (ρ), as shown in Equation 3. The model also allows an upper limit (L_F) to be placed on fuel production volumes from the set of all fuel production pathways for a specific fuel (F), as shown in Equation 4.

Objective Function:

$$\min TC = \sum_t \sum_p \left(C_{t,p} \times FS_{t,p}\right) \qquad \text{Equation 1}$$

Production and Supply Constraints:

$$\sum_t FS_{t,p} \leq FS_p \qquad \text{Equation 2}$$

$$\sum_{t\in\rho} \sum_p \left(\gamma_t \times FS_{t,p}\right) \geq D_\rho \qquad \text{Equation 3}$$

[1] https://developers.google.com/optimization

$$\sum_{t \in F} \sum_{p} \left(\gamma_t \times FS_{t,p}\right) \leq L_F \qquad \text{Equation 4}$$

In addition to the basic fuel production and supply constraints, a Low Carbon Fuel Standard (LCFS) constraint is imposed. For this constraint, the total number of credits generated each year must be greater than or equal to the total number of deficits generated each year. This constraint is shown in Equation 5, where the total credits generated for each fuel production pathway (Cr_t) is determined using the LCFS credit generation equation defined in regulation[2], and the net number of credits must be positive.

LCFS Constraint:

$$\sum_{t} \left(\sum_{p} FS_{t,p} \times Cr_t\right) \geq 0 \qquad \text{Equation 5}$$

Where:

$$Cr_t = \left(CI_{benchmark,t} - \frac{CI_t}{EER_t}\right) \times \gamma_t \times EER_t \times 1x10^{-6} \qquad \text{Equation 6}$$

$CI_{benchmark}$ is the LCFS benchmark compared against a fuel production pathway, CI_t is the carbon intensity for producing fuel using a given production pathway, and EER_t is the energy efficiency ratio as defined in the LCFS regulation.

Finally, the model has capabilities to impose blending constraints and co-product constraints, in which a constraint is established such that the energy generated for a combined set of source fuel pathways (S) does not exceed an upper bound fraction (δ_u) for energy provided from overall technologies within the total blending pool (B), but also meets a lower bound fraction (δ_l) for energy provided within the total blending pool.

Blending Constraint:

$$\sum_{t \in S} \sum_{p} \left(\gamma_t \times FS_{t,p}\right) \leq \delta_u \sum_{t \in B} \sum_{p} \left(\gamma_t \times FS_{t,p}\right) \qquad \text{Equation 7}$$

$$\sum_{t \in S} \sum_{p} \left(\gamma_t \times FS_{t,p}\right) \geq \delta_l \sum_{t \in B} \sum_{p} \left(\gamma_t \times FS_{t,p}\right) \qquad \text{Equation 8}$$

No other policy types have been endogenized into the optimization model. Other policy effects can be explored with this model by changing fuel production costs over time or by setting specific limits on feedstock or fuel volumes. For instance, the Renewable Fuel Standard can be represented in the model through an exogenous subsidy for specific fuels over time. Other tax credits or disincentives can similarly be estimated and utilized to shift expected fuel production costs.

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[2] https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf

Example Scenario Assumptions

Fuel Pool Demand

CATS is an optimization model that chooses the quantity of fuel that is produced through specific feedstock-technology pathways to satisfy the demand of specified fuel pools at the lowest possible cost. For the example scenario, eight different fuel pools were defined:

1. Gasoline fuel demand
2. Diesel fuel demand
3. Compressed natural gas (CNG) fuel demand
4. Light-Duty vehicle electricity demand
5. Heavy-Duty vehicle electricity demand
6. Light-duty vehicle hydrogen demand
7. Heavy-duty vehicle hydrogen demand
8. Intrastate jet fuel demand

If a scenario is feasible, the model will determine the lowest cost mixture of fuel for each of the eight fuel pools such that the overall model constraints are met. This section documents the assumptions and methods used to define fuel pool demand through 2045.

Gasoline Fuel Pool

Demand for California's gasoline fuel pool has been estimated using the gasoline vehicle stock for light-duty ($S_{LDV,G}$) vehicles and the off-road gasoline fuel demand ($D_{PW,G}$) outputs from the Proposed Scenario in the CARB 2022 Scoping Plan Update.[3] Medium-duty vehicle stock estimates ($S_{MDV,G}$) were derived using EMFAC2021 v1.0.2 total stock numbers with subtractions made to account for vehicle electrification affiliated with Advanced Clean Trucks.

The total gasoline fuel pool demand (D_G) was determined using Equation 9, where VMT_{LDV} is the average annual vehicle miles traveled (VMT) per vehicle in California's fleet as estimated using an October 2018 snapshot of California Department of Motor Vehicles (DMV) data. VMT_{MDV}, $FE_{LDV,}$ and FE_{MDV} are the estimated fleet-average vehicle miles traveled and fuel economies in miles per gallon, respectively, given by the EMFAC2021 v1.0.2 model for gasoline-consuming vehicles.[4,5] The EMFAC 2007 light-duty vehicle categories[6] and EMFAC

[3] https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

[4] https://arb.ca.gov/emfac/emissions-inventory/3f0f3c7489b82ed889c6b740111452af6f718923

[5] VMT_{MDV} vales were altered then scaled relative to EMFAC values to ensure fuel volumes in 2022 were consistent with reported gasoline and diesel fuel volumes in the LRT for 2022

[6] LDA, LDT1, and LDT2

2007 medium-duty vehicle[7] categories were used for classifying vehicle characteristics to calculate these averages.

$$D_G = S_{LDV,G} \times \frac{VMT_{LDV,G}}{FE_{LDV,G}} + S_{MDV,G} \times \frac{VMT_{MDV,G}}{FE_{MDV,G}} + D_{PW,G} \qquad \text{Equation 9}$$

To estimate average annual VMT for light-duty vehicles, the DMV data were processed to select the subset of light-duty vehicles in the state, by Vehicle Identification Number (VIN), that had 2 or more odometer readings at different time periods. The age for each vehicle at the time of the odometer reading was used to aggregate VMT observations, and average annual VMTs were calculated between each odometer reading. Using this approach, California's total LDV fleet was estimated to have an annual average VMT of 12,443 miles per vehicle per year. For the example scenario, which is conservative in relation to strategies to reduce state-wide VMT, the light-duty vehicle VMT is held constant through 2045. Medium-duty vehicle VMT is assumed to follow trends in EMFAC. The LCFS EV VIN Decoder was used to separate Battery Electric Vehicles and non-Battery Electric Vehicles within the DMV database.[8]

Diesel Fuel Pool

Demand for California's diesel fuel pool has been estimated using the diesel vehicle stock for heavy-duty ($S_{HDV,D}$) and medium-duty ($S_{MDV,D}$) vehicles and the off-road diesel fuel demand ($D_{PW,D}$) outputs from EMFAC. Adjustments were made to the released EMFAC2021 v1.0.2 stock values to account for vehicle electrification trends anticipated to occur due to Advanced Clean Fleets (ACF). These changes in diesel stock incorporate the estimated impacts on vehicle stock for the final ACF regulation package submitted to OAL on June 13th, 2023.[9]

The total diesel fuel pool demand (D_D) was determined using Equation 10, where VMT_{HDV}, VMT_{MDV}, FE_{HDV}, and FE_{MDV} are the estimated fleet-average vehicle miles traveled and fuel economies in miles per gallon, respectively, given by the EMFAC2021 v1.0.2 model for diesel-consuming vehicles.[10, 11] The vehicle weight categories for energy aggregation used the EMFAC 2007 heavy-duty vehicle classification (HHDT) and EMFAC 2007 medium-duty vehicle classification.[7]

[7] LHDT1, LHDT2, MHDT, MH, OBUS, SBUS, and UBUS

[8] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/draftmethodology_basecredits_nonmetered.pdf

[9] https://ww2.arb.ca.gov/rulemaking/2022/acf2022

[10] https://arb.ca.gov/emfac/emissions-inventory/3f0f3c7489b82ed889c6b740111452af6f718923

[11] VMT vales were altered then scaled relative to EMFAC values to ensure fuel volumes in 2022 were consistent with reported gasoline and diesel fuel volumes in the LRT for 2022

$$D_D = D_{HDV} \times \frac{VMT_{HDV,D}}{FE_{HDV,D}} + S_{MDV} \times \frac{VMT_{MDV,D}}{FE_{MDV,D}} + D_{PW,D} \qquad \text{Equation 10}$$

Compressed Natural Gas Fuel Pool

Compressed natural gas energy demand is calibrated to 2022 LCFS reported volumes and assumed to follow projections in the Proposed Scenario from the 2022 Scoping Plan Update.

Light-Duty Zero Emission Vehicles

The October 2018 DMV snapshot suggests that the average California battery electric vehicle (BEV) has an average annual VMT of 10,400 miles per year (84 percent ICE vehicle VMT). By 2031, it was assumed that BEVs would no longer have a substantial range or charging-time disadvantage compared to gasoline-powered light-duty vehicles, and would therefore achieve 100 percent of the ICE vehicle VMT. The fuel economy for BEVs was assumed to be 3.3 mi/kWh, which is consistent with the combined city/highway EPA fuel economy estimate for a Tesla Model Y AWD performance vehicle. Annual BEV stocks and plugin-hybrid electric vehicle (PHEV) stocks followed the Proposed Scenario in the 2022 Draft Scoping Plan Update, with updates made to reflect actual EV counts for 2022, which includes estimated fleet changes occurring due to Advanced Clean Cars 2 (ACC2). PHEV all-electric miles and fuel economy each year were assumed to follow EMFAC2021 values. Taken together, this allowed for an estimate of the total energy demand affiliated with light-duty electric vehicles in California each year through 2045.

For fuel demand associated with hydrogen fuel cell (H2) vehicles, the total LDV H2 stock followed the Proposed Scenario of the 2022 Draft Scoping Plan Update. H2 Vehicles were assumed to have the same VMT as the average California vehicle fleet, with an average energy economy ratio of 2.5[2] compared to the ICE vehicle fleet each year.

Heavy-Duty Zero Emission Vehicles

For the heavy-duty vehicle fleet, vehicle stock numbers for total HDVs were estimated by making modifications to EMFAC2021 v.1.0.2 to update hydrogen and battery electric vehicle stock numbers to account for the anticipated impacts of ACF associated with the final regulation package submitted to OAL on June 13th, 2023. To estimate the split between electric and hydrogen vehicles, staff applied adjustment factors from the Initial Statement of Reasons of the ACF Regulation. The adjustments reflect the assumption that 10 percent of day cab tractors will be hydrogen until 2027 and 25 percent afterwards, and that sleeper cabs are split 50:50 between electric and hydrogen vehicles. All other vehicles are assumed to be electric until 2026, then starting in 2027 and beyond, 90 percent electric and 10 percent hydrogen.

The electric vehicle fuel economy from EMFAC2021 for the HDV vehicle fleet as categorized by EMFAC2007 categories (HHDT) was used. The heavy-duty hydrogen vehicle energy economy ratio was assumed to be 1.9, consistent with the LCFS regulation.[2] Average VMT for HDVs as specified in EMFAC2021 was used for both hydrogen and electric vehicles.

Calibration of Gasoline and Diesel Pool Demand with 2022 LCFS Reporting Tool (LRT) Data

The EMFAC VMT values for HDV and MDV fleets in 2022 were adjusted to ensure estimated fuel volumes were consistent with reported volumes. While 2022 VMT values were directly modified, VMT for all other years scaled to ensure that the ratio of VMT in a given year relative to the 2022 VMT value remained consistent with EMFAC2021 v1.0.2. This modification ensured that calculated 2022 gasoline and diesel pool energy values that were predicted using vehicle stock estimates and EMFAC fuel economy parameters would align with the 2022 data reported in the LRT.

This calibration changed the EMFAC HDV VMT value from 44,519 miles per year in 2022 to 38,571 miles per year (13% change) and changed the EMFAC MDV VMT value from 12,078 miles per year in 2022 to 10,026 miles per year (17% change).

Intrastate Jet Fuel

For intrastate jet fuel, demand was taken using jet fuel consumption volumes as found in the Baseline Scenario of the 2022 Scoping Plan.

Feedstock Supply Curves

Fats, Oils, and Greases

Feedstock supply for fats, oils, and greases were estimated using biodiesel price data from Argus and EIA's biodiesel feedstock reports.[12, 13] For analysis, virgin feedstocks consist of soybean oil, corn oil, and canola oil. Waste feedstocks were assumed to consist of tallow and white and yellow grease. A linear regression was used for each feedstock category (i) to estimate how oil supply (S_o) changed as a function of biodiesel cost (C_{BD}). The regression was performed using the natural log of feedstock supply and natural log of biodiesel price such that the estimated regression coefficient (β) would approximate the percent change in supply for feedstocks relative to a percent change in the market price of biodiesel. Coefficient estimates using this methodology are shown in Table 1.

$$\ln(S_{O,i}) = \alpha + \beta \times \ln(C_{BD}) + \epsilon \qquad \text{Equation 11}$$

[12] https://www.eia.gov/biofuels/biodiesel/production/
[13] https://www.eia.gov/biofuels/update/

Table 1. Regression coefficient estimates to estimate FOG supply

Feedstock Type	Coefficient Estimate
Virgin Oil	0.394
Waste Oil	1.104

Using the biomass production costs and conversion efficiency parameters discussed in the *fuel production section* of this document, a price for biodiesel was estimated for various feedstock costs, which were selected based on cost ranges that have been seen over the past several years. These biodiesel prices were then used alongside the regression coefficients estimated in Table 1 above to generate a feedstock supply curve for virgin oil and waste oil used in the CATS model.

Table 2. Estimated feedstock supply curve for waste oil and virgin oil

Feedstock price ($/ton)	600	800	1000	1200	1400	1600	1800	*2000*	*2200*
Incremental Waste Oil (tons)	1688294	345582	345582	345582	345582	345582	345582	345582	
Incremental Virgin Oil (tons)	4431287	331702	331702	331702	331702	331702	331702	331702	inf

Dairy Gas

Estimates for the cost of using dairy gas for energy were derived from Jaffe et al. (2016), which was used for CARB's Dairy Progress Analysis Report.[14] Costs were estimated for both dairy gas that is converted to renewable natural gas suitable for pipeline injection, with curve values being tied to cluster dairy projects, and for dairy gas that is used to produce electricity through a solid-oxide fuel cell (SOFC). Based on the supply curves in the Dairy Progress Analysis Report, only about 6.7 trillion Btu of dairy gas is likely to be economical to inject into pipelines compared to fuel cell use. As such, 6.7 trillion Btu of dairy gas is allocated for availability as an RNG feedstock on the supply curve for this model. At dairy gas costs over ~$50 per MMBtu, SOFC conversion pathways are likely to be a lower-cost opportunity for using dairy gas for energy compared to building out pipelines for injection. 10.2 trillion Btu of dairy gas supply was assumed to be available for SOFC use. Assumptions affiliated with the capital costs for fuel cells are detailed in the section discussing *Renewable Natural Gas-to-Fuel*.

[14] https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf

Table 3. Estimated In-State Dairy Gas Supply Curve

Cost ($/MMBtu)	40	50	75	90	100	125
Incremental Dairy Gas to RNG (MMBtu)	2801212	3892104				
Incremental Dairy Gas to Electricity (MMBtu)	0	7782698	2448129	14306	1039	420

In addition to in-state dairy gas supply, out-of-state RNG supply is also available. Availability estimates were derived from a report commissioned by the American Gas Foundation (AGF).[15] The AGF total RNG estimate derived from manure was 231.2 trillion Btu. Volumes were adjusted to account for the in-state volumes, eligibility requirements, and methane production assumptions. Staff estimates that the total available supply of biomethane affiliated with out-of-state facilities that may be available for use in California is approximately 9.65 trillion Btu.

To determine a percent breakdown between possible electricity generation pathways and RNG pathways, the original AGF methane estimates were used. California's amount of in-state supply was subtracted from the Pacific Region, and all biomethane volumes contained in states within the western grid electricity interconnection (the WECC) were assumed to direct biomethane toward electricity generation. This resulted in an estimate of approximately 15 percent of the adjusted biomethane volumes being available for electricity pathways.

Given that CARB staff is not aware of any research done to date to further understand cost curves associated with bringing manure-derived biomethane supplies to market from regions outside of California, the price points used for the in-state supply curve were used as a proxy for out-of-state costs. Volumes were apportioned to each price bin based on the percent of biomethane that fell into a specific price bin for California's supply as found in Table 3.

Table 4 lists the total estimated supply of out-of-state manure-based biomethane resources that may be available for use in California.

Table 4. Out-of-state Biomethane Supply Curve for Dairy and Swine Manure

Cost ($/MMBtu)	40	50	60	75	80	90	100	125
OOS RNG Dairy (MMBtu)	1594928	5174861	0	1393893	0	8145	592	239
OOS Electricity Dairy (MMBtu)	0	1472429	0	0	0	0	0	0

[15] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf

Electricity

Because the model does not institute time-of-day specificity for optimization, electricity is assumed to be available at an effectively infinite quantity for transportation at a price of $80 per MWh, approximating the social marginal cost for providing electricity in California.[16]

Landfill Gas

The supply curve for landfill gas was taken from Jaffe et al. (2016).[17] Adjusting for inflation to late 2021 values, this supply curve suggests that almost 32 billion cubic feet of supply might be available at costs under $12 per MMBtu.

To account for out of state supply, the Landfill Methane Outreach Program database was utilized.[18] All complete facilities with RNG volumes injected into the pipeline network were considered. This amount totaled 91 trillion Btu of pipeline-grade RNG from facilities nationwide. The Jaffe et al. (2016) supply quantities at each price point were scaled to encapsulate the total national supply.

Other Conventional Resources

For purposes of modeling relevant to California, conventional resource supply was assumed to be at approximately infinite quantity. Prices were approximated using spot market prices for the commodities in 2022. These prices are given in Table 5.

Table 5. Assumed commodity prices for conventional resources

Commodity	Assumed Price
Crude Oil	$90 per barrel
Corn	$7 per bushel
Natural Gas	$6 per MMBtu

Fuel Production Costs, Conversion Efficiency, and Carbon Intensity

Biomass-based Diesel

Conversion costs and yields were estimated using a linear regression to predict renewable diesel and biodiesel market prices in dollars per gallon as a function of feedstock prices. This is shown in Equation 12 below, where α is the intercept, or estimated fixed costs for

[16] https://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf
[17] https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/13-307.pdf
[18] https://www.epa.gov/lmop/landfill-gas-energy-project-data

production in dollars per gallon, β is the estimated conversion efficiency in pound per gallon for a given feedstock, C_{fs} is the price of feedstock, C_{BBD_fs} is the price of fuel derived from that feedstock, and $\in$ is the regression error term. Price data for commodities came from Argus who has been monitoring biomass-based diesel feedstock prices since August of 2020 and renewable diesel fuel costs since November 2021. Prices affiliated with used cooking oil were used to be representative of waste oil production pathways, while prices affiliated with soybean oil were used to be representative of virgin oil.

$$C_{BBD\_fs} = \alpha + \beta \times C_{fs} + \in \qquad \text{Equation 12}$$

The resulting fixed costs and yield estimates are shown in Table 6. The fixed cost term encompasses production costs as well as various subsidies that are not priced independently on the market that producers have been able to capture over the timeframe of the Argus data.

Table 6: Regression results for estimating fixed costs and yields for biomass-based diesel as feedstock prices vary over time.

Technology	Estimated Fixed Costs ($/ton)	Estimated Yield (MJ/ton)
BD Virgin Oil	$53	31520
BD Waste Oil	$330	34064
RD Virgin Oil	$872	38878
RD Waste Oil	$1,069	37655

Note: In addition to the estimated fixed costs, it is assumed that distribution costs are equivalent to about 20 cents per gallon, or an additional $53 per ton of feedstock should be added (MacKinnon et al., 2020).[1]

The carbon intensities for biomass-based diesel pathways were estimated by averaging together the carbon intensity scores for all LCFS-certified pathways[19] relevant to the biomass-based diesel production process.

Table 7. Carbon Intensity Estimates for Bio-/Renewable Diesel

Technology	Carbon Intensity Estimate (gCO_2e/MJ)
BD Virgin Oil	55
BD Waste Oil	25
RD Virgin Oil	56
RD Waste Oil	31

[19] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx

Renewable Gasoline and Alternative Jet Fuel

Conversion costs and yields were estimated for renewable gasoline using coefficient estimates (fixed costs and conversion efficiency) for the renewable diesel linear regression as presented in Equation 12. Renewable gasoline is assumed to cost more to produce than renewable diesel due to the increased need for additional hydrocracking to yield a lighter fuel compared to diesel. This could potentially add as much as 10 cents per gallon[20], which translates to an additional $33 per ton of feedstock for renewable gasoline compared to renewable diesel.

Argus captures pricing data on the US West Coast for alternative jet fuel (AJF). This price is assumed to be associated with AJF produced from virgin oils. Because AJF is typically a co-product associated with the production of renewable diesel, regression analysis was used to estimate how the price of AJF changes with respect to the price of renewable diesel.

$$C_{AJF} = \alpha + \beta \times C_{RD} + \epsilon \qquad \text{Equation 13}$$

Where C_{AJF} is the cost of AJF on the wholesale market, α is a fixed effect, and β is the coefficient estimating how the AJF prices change with respect to the cost of renewable diesel in California. Equation 13 was used to predict an entire set of costs over time for AJF affiliated with UCO-produced renewable diesel and soybean-oil-produced renewable diesel. Regression was then performed on these predicted costs relative to UCO and soybean-oil prices to estimate a fixed cost and yield for producing AJF to be used in the model.

Table 8 shows the estimated fixed costs and estimated yield for renewable gasoline (RG) and AJF. Carbon intensities are assumed to be identical to the CI values for renewable diesel.

Table 8. Estimating fixed costs and yields for renewable gasoline and alternative jet fuel

Technology	Estimated Fixed Costs ($/ton)	Estimated Yield (MJ/ton)
RG Virgin Oil	$905	38878
RG Waste Oil	$1,102	37655
AJF Virgin Oil	$961	37437
AJF Waste Oil	$1,155	36259

Note: In addition to the estimated fixed costs, it is assumed that distribution costs are equivalent to about 20 cents per gallon, or an additional $53 per ton of feedstock should be added (MacKinnon et al., 2020).[21]

[20] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-18284rev1.pdf

[21] https://ww2.arb.ca.gov/sites/default/files/2020-12/16RD011.pdf

Gasoline and Diesel

Gasoline and diesel carbon intensity values were taken directly from the Lookup Table values in the LCFS regulation. Production costs and yields were estimated using regression analysis on spot market prices.[22] Ultra-low sulfur diesel and Los Angeles RBOB (C_{conv}) were compared to West Texas Intermediate crude oil prices (C_{oil}).

$$C_{conv} = \alpha + \beta \times C_{oil} + \epsilon \qquad \text{Equation 14}$$

Table 9. Estimated fixed costs and yields for CARBOB and ULSD

Technology	Estimated Fixed Costs ($/barrel)	Estimated Yield (MJ/barrel)
CARBOB	$15	4687
ULSD	$3	4528

Note: An additional $7 per barrel should be added to account for the 20 cent per gallon distribution costs needed to bring conventional fuels to the California market (MacKinnon et al. 2020).

Ethanol

Like biomass-based diesel, yields and fixed costs were estimated for ethanol using a regression similar to Equation 12. Corn costs in dollars per bushel and ethanol costs in dollars per gallon were obtained from USDA weekly reports from July 2018 through May 2022.[23] This resulted in fixed cost estimates of $0.30 per bushel of corn.

The average carbon intensity for corn ethanol pathways registered under the LCFS is 66 gCO_2e/MJ. In addition, it is possible to use carbon capture and sequestration (CCS) technology on ethanol plants to capture the mostly-pure CO_2 stream generated during fermentation. It is assumed that CCS can be added to ethanol plants resulting in capture costs of $50 per metric ton of CO_2e captured. From a design-based pathway submitted to CARB, it is estimated that CCS-ethanol facilities may prevent the release of 36 gCO_2e/MJ of ethanol[24], translating to an additional cost of $0.42 per bushel of corn. It is assumed that an additional 5 gCO_2e/MJ ethanol emissions may result from the CCS process, giving a total carbon intensity for the process of 35 gCO_2e/MJ.

[22] https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm

[23] https://mymarketnews.ams.usda.gov/filerepo/reports?field_slug_id_value=&name=NW_GR212&field_slug_title_value=&field_published_date_value=&field_report_date_end_value=&field_api_market_types_target_id=All&page=0

[24] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/d0005_report.pdf

Table 10. Estimated costs and yields for ethanol production technology

Technology	Estimated Fixed Costs ($/bu)	Estimated Yield (MJ/bu)
Ethanol	$0.30	235
Ethanol with CCS	$0.72	235

Note: Accounting for distribution costs of 20 cent per gallon of conventional fuel adds another $0.58 per bushel of corn to the total cost to provide transportation fuel.

CNG and Renewable Natural Gas-to-Fuel

Compressed natural gas (CNG) fuel costs from the Alternative Fuel Data Center[25] (AFDC) in conjunction with natural gas prices were used to estimate the conversion and distribution costs for converting natural gas and renewable natural gas to CNG for use in vehicles. AFDC surveyed various stations to provide an average price of $2.88 per GGE of CNG ($26.23 per MMBtu) for January of 2022, a time when natural gas costs for industrial users in California were $14.28 per MMBtu.[26] Taken together, this suggests that conversion costs and margins may be approximately $11.40 per MMBtu. This value was assumed to be the conversion and distribution cost for converting from any renewable or conventional natural gas sources to provide CNG for use in vehicles.

Carbon intensity (CI) estimates for CNG for fossil natural gas and landfill gas came from the LCFS lookup table.

The CI for CNG derived from dairy biogas is estimated to be an average of -293 gCO2e/MJ, based on evaluation of 8 certified LCFS dairy biogas to CNG pathways. Due to the wide range of CI scores associated dairy biogas pathways, the standard deviation for this CI is ±127 gCO2e/MJ, therefore CI results may vary widely between individual pathways. Data from these pathways is also used to compute carbon intensities for alternate finished fuels (electricity from dairy biogas, hydrogen from book-and-claim of pipeline-injected dairy biomethane).

Electricity Pathways

For grid-electricity, the carbon intensity is assumed to decline at the general emissions rate decline seen in Proposed Scenario of the 2022 Draft Scoping Plan Update. Table 11 below shows how this translates into an assumed grid-average carbon intensity for modeling.

[25] https://afdc.energy.gov/files/u/publication/alternative_fuel_price_report_january_2022.pdf
[26] https://www.eia.gov/dnav/ng/hist/n3035ca3m.htm

Table 11. Estimated Grid Average Electricity CI through 2045

Year	Scoping Plan Scenario CI Relative to 2023	Estimated Grid-Avg CI
2023	100%	81
2024	105%	84.7
2025	109%	88.4
2026	107%	86.9
2027	105%	85.4
2028	103%	83.8
2029	98%	79.1
2030	92%	74.4
2031	88%	71.3
2032	84%	68.3
2033	80%	65.2
2034	77%	62.1
2035	73%	59.1
2036	71%	57.8
2037	70%	56.6
2038	68%	55.4
2039	67%	54.2
2040	65%	53.0
2041	64%	51.8
2042	63%	50.6
2043	61%	49.5
2044	60%	48.3
2045	20%	16.5

For electricity provided using zero-carbon resources, it is assumed that there will be a "green" premium equivalent to the cost of Portfolio Content Category 1 (PCC1) RECs, which yields a zero-CI pathway. The City of Burbank instituted a green tariff program in 2020 which is covered using only PCC1 RECs.[27] Their current green tariff additive rate is $0.018 per kWh, or $18/MWh, which is assumed to be the cost of PCC1 RECs for modeling the zero-CI pathway. This value is assumed to be constant through the entire modeling horizon.

Grid electricity that is used to charge vehicles is assumed to follow the social marginal cost as discussed in the *feedstock supply curve section*.

Consistent with the 2022 Scoping Plan Update, dairy gas that is used to generate electricity for use as a transportation fuel is expected to use non-combustion technologies, such as solid-oxide fuel cells (SOFC). SOFCs were assumed to be 57 percent efficient, and to cost

[27] https://burbank.granicus.com/MetaViewer.php?view_id=2&clip_id=8917&meta_id=363607

$5,500 per kW-output, with 10 percent operation and maintenance costs annually over a 15-year financial lifetime with a 12-percent discount rate. This created a capital cost estimate of $17 per MMBtu of renewable natural gas used in the fuel cell. This value was incorporated into the supply curves generated for the Dairy Progress Analysis and is reflected in feedstock supply curve for dairy gas to electricity in the model.

The CI for electricity produced from dairy biogas in a SOFC is estimated to be –440 gCO2e/MJ, prior to energy efficiency ratio adjustments. This CI was generated using the aforementioned analysis of dairy biogas pathways, assuming a 57% conversion efficiency of dairy biogas to electricity via fuel cell.

Hydrogen

There are numerous pathways for producing hydrogen. For modeling, the following pathways were considered, with cost and carbon intensity calculation information detailed below.

Table 12. References for hydrogen production process assumptions

Pathway	Cost Assumptions	Carbon Intensity Assumptions
H_2 from fossil NG	NREL Hydrogen Analysis Production Model [28]	LCFS lookup table
H_2 from fossil NG + CCS	NREL Hydrogen Analysis Production Model	Discussion below
H_2 from dairy gas	NREL Hydrogen Analysis Production Model	Discussion below
H_2 from landfill gas	NREL Hydrogen Analysis Production Model	LCFS lookup table
H_2 from electrolysis	Costs from CARB contract 16RD011 (MacKinnon et al., 2020)	LCFS lookup table

Hydrogen Distribution

Aside from a 17-mile pipeline in Torrance and Wilmington, no major hydrogen pipeline network exists in California. Hydrogen is shipped by tube trailer from the point of production to hydrogen fueling station. MacKinnon et al. (2020) used the DOE's H2A Delivery Analysis

[28] NREL 2018. "H2A: Hydrogen Analysis Production Models." *https://www.nrel.gov/hydrogen/h2a-production-models.html*.

[29] https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf

model to estimate a representative distribution and dispensing combined cost of $4.50/kg. This amount is added to the feedstock and cost of conversion for any hydrogen pathway.

Steam Methane Reforming with and without CCS

Conversion costs for SMR, without and with carbon capture and sequestration, are calculated using the NREL's Hydrogen Analysis Production Models. NREL's "future models" were used to predict 2022 prices, with all other inputs set to the NREL default. The model evaluates a 341 MT/day hydrogen plant. The overall costs for these modeled scenarios align with Friedmann et al. (2019) [29], but also break out the cost components (Table 13) so that the cost of conversion, without feedstock costs, can be estimated. NREL cost estimates are in 2016 dollars, which staff converted to 2021 year dollars using the Consumer Price Index. The carbon intensity for hydrogen produced from fossil natural gas is equivalent to the LCFS Lookup Table value found in the regulation.

Table 13. NREL Hydrogen Analysis Production Model, 344 MT/d Hydrogen SMR Plant with no CCS

Cost Component	Cost Contribution ($/kg – 2016 dollars)	% of H_2 Cost
Capital Costs	*$0.1226*	*10.2%*
Decommissioning Costs	*$0.0006*	*0.0%*
Fixed O&M	*$0.0606*	*5.0%*
Feedstock Costs	*$0.9271*	*76.8%*
Other Raw Materials	*$0.0000*	*0.0%*
Byproduct Credits	*$0.0000*	*0.0%*
Other Variable Costs (i.e., utilities)	*$0.0963*	*8.0%*
Total	**$1.2072**	

The SMR cost of conversion can be applied to any feedstock that has been cleaned to pipeline grade methane, including from dairies and landfills.

The carbon intensity for hydrogen produced from North American landfill gas is estimated at being 99 gCO_2e/MJ, consistent with the LCFS Lookup Table value.

The carbon intensity for hydrogen produced from book and claim of dairy biomethane (as a feedstock, not a process fuel) is modeled to be –353 gCO2e/MJ. This carbon intensity was developed from the Lookup Table value [30] of 117.67 g CO_2e/MJ (HYF pathway), with fossil natural gas feedstock replaced with dairy biomethane.

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[29] https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf

[30] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut-doc.pdf?_ga=2.167828897.1073658880.1652887780-237633646.1594072165

The carbon intensity for fossil natural gas hydrogen with carbon capture technology at the point of production was estimated to be about 60 gCO_2e/MJ. This carbon intensity was developed from the Lookup Table value of 117.67 g CO_2e/MJ (HYF pathway) less a conservative 60 gCO_2e/MJ due to the estimated reduction potential from using CCS.

The potential for CCS emissions reductions was determined based on stoichiometry of steam methane reforming (SMR) with the water-gas shift reaction:

$$CH_4 + 2H_2O \rightleftharpoons CO_2 + 4H_2$$

1.371 MJ of natural gas is required to produce 1 MJ of hydrogen via steam methane reforming (SMR). [31] If all CO_2 is captured (both feedstock and process natural gas), then for every mole of methane input into the process, there will be 3.67 moles (44/12) of CO_2 output that is potentially capturable per the following conversion factors:

Conversion Factor	Units
1.37	MJ CH_4/MJ H_2
27.42	g CH_4/MJ H_2
75.40	g CO_2 emissions potentially capturable/MJ H_2

Staff assumes that 80 percent to 90 percent capture efficiency is a reasonable estimate for the technology. [32]

Older SMR processes typically use an amine separation, which is selective for CO_2, resulting in a very high capture efficiency (90 percent or higher). Many modern hydrogen production facilities are likely to use membrane separation to create a higher purity hydrogen stream. If these facilities are also using CCS, they will add amine separation as an additional step to purify the CO_2. This two-step process will lower the CO_2 capture efficiency. Staff assumes process efficiency may drop to about 85 percent to 90 percent.

An 80 percent to 90 percent capture efficiency would contribute reductions of between 60 to 70 gCO_2e/MJ to the pathway. Therefore, a total pathway carbon intensity of 117 gCO_2e/MJ

[31] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-05.pdf[32] https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf[33] https://greet.es.anl.gov/greet_aviation

[32] https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf[33] https://greet.es.anl.gov/greet_aviation

less the 60 to 70 gCO_2e/MJ for CCS indicates that a modeled value of 60 gCO_2e/MJ may be appropriate for these pathways.

Electrolytic Hydrogen

For hydrogen production using electrolytic processes, the LCFS Lookup Table pathways were used for carbon intensity values for grid-average electricity and for zero-carbon electricity. Electrolyzer costs were approximated to follow the costs for alkaline electrolytic cells (AEC) from MacKinnon et al., 2020. For grid-average electricity, the capacity factor was assumed to be 70 percent, while for zero-carbon electricity the capacity factor was assumed to be 34 percent due to the intermittent nature of renewable electricity. Additionally, the aggregate dispensing/distribution cost of $4.50 per kg H_2, or $40 per MMBtu was added to account for costs needed to convert from commodity hydrogen to transportation fuel. The costs shown in Table 14 do not include the cost of the electricity. Conversion efficiency for the AEC process is assumed to be 70 percent, and hydrogen distribution losses are estimated at being 18 percent (MacKinnon et al. 2020). Taken together, this provides an overall conversion yield of 2066 MJ of hydrogen delivered per MWh of electricity used to produce hydrogen.

Table 14. Conversion costs for electrolytic hydrogen using alkaline electrolytic cells

Electricity Source	Conversion Cost ($/MWh)
Grid-average Electricity (70% capacity factor)	$86
Zero-carbon electricity (34% capacity factor)	$137

The CI values for electrolytic hydrogen production were assumed to align with the Lookup Table values found in the LCFS regulation.

Direct Air Capture

Direct air capture technology is integrated into the model following the cost assumptions in the 2022 Draft Scoping Plan Update. Costs through 2030 are assumed to be $1000 per metric ton, declining to $236 per metric ton by 2045.

Exogenous Subsidies and Additional Costs

In addition to costs considered above, there are numerous federal subsidies that fuel producers might realize which includes the Federal Renewable Fuel Standard (RFS) and provisions from the recently passed Inflation Reduction Act (IRA).

Biomass-based Diesel

Biomass-based diesel can generate D4 Renewable Identification Numbers (RIN) under the Renewable Fuel Standard. For modeling purposes, D4 RINs were assumed to be valued at $1.45. Biodiesel has an ethanol equivalence value of 1.4 under the RFS, while renewable diesel has an ethanol equivalence value of 1.7, although renewable diesel can receive less than this. Based on public comments received, an equivalence value of 1.6 for renewable diesel, and 1.5 for renewable gasoline has been selected (which is eligible for D5 RINs, with an estimated valued of $1.49 per RIN). This translates into an exogenous subsidy of $0.017 per MJ of biodiesel and $0.018 per MJ of renewable diesel, and $0.019 per MJ of renewable gasoline used in California.

Direct Air Capture

Direct Air Capture is eligible for tax credits provided under section 45(Q) of the IRS tax code. This provides an incentive of $180 per metric ton of CO_2 captured using direct air capture if injected into a geologic reservoir, and $130 per metric ton of CO_2 captured if used or injected into an oil and gas field. For modeling purposes, an exogenous subsidy of $130 per metric ton of CO_2 captured using direct air capture was assumed.

Ethanol and Ethanol with CCS

Corn-based ethanol is eligible to generate D6 RINs under the RFS. To model the exogenous subsidy from the RFS, D6 RINs were assumed to be valued at $1.13, translating into a subsidy for ethanol production of $0.014 per MJ of ethanol produced. For ethanol with CCS, provisions under 45(Q) of the Internal Revenue Service's tax code also apply, which provides between $60 and $85 per metric ton of CO_2 captured. CO_2 that is captured and used or captured and stored in oil and gas fields is eligible for $60 per metric ton. For modeling purposes, it was assumed that the majority of CO_2 captured from ethanol would either be used or stored in oil and gas fields. This translates to a subsidy value of approximately $0.002 per MJ of ethanol produced with CCS. In addition to the RIN value, this provides a total subsidy of approximately $0.02 per MJ for ethanol.

E85

The cost of producing ethanol to use as E85 is the same as producing ethanol that is blended into gasoline to create E10. However, because the demand for E85 is limited due to vehicle technology, and providing E85 to customers requires tailored infrastructure and blender pumps, there is additional cost associated with bringing E85 to market relative to E10. This cost is believed to be reflected by D6 RIN prices ($1.13 per gallon). For modeling purposes, all costs for E85 are assumed to be identical to ethanol, but no exogenous subsidy from the RFS is included, as that reflects the additional cost necessary to bring E85 to market.

Electricity

Under existing LCFS provisions, low-CI electricity may be matched with electric vehicles and hydrogen pathways to further lower the carbon intensity of these transport fuel pathways. Because California's grid is not presently operating at zero-CI, the cost of procuring zero-CI electricity for customers is at a premium compared to using grid electricity. California's Renewable Portfolio Standard establishes a set of tradable credits that utilities utilize to account for renewable energy resources and compliance with the standard. Discussion with stakeholders has indicated that marginal renewable electricity supplies can be obtained at costs between $12 and $18 per MWh. As such, zero-carbon electricity generated from wind and solar resources is assumed to cost $18 per MWh more than grid electricity. This is consistent with the City of Burbank's green tariff program.[27]

Multiple off-road categories that were explicitly modeled in the 2022 Scoping Plan Update are rapidly electrifying and are able to generate credits under the LCFS. Staff utilized various methods to estimate and project credits from these sources into the future. Regression analysis of the form found in Equation 15 was used to estimate Fixed guideway credits and eTRU credits.

$$Credits_Q = \alpha + \beta_1 \times Q + \beta_2 \times CI_{20xx} + \beta_3 \times CI_{20xx} \times Q + \epsilon \qquad \text{Equation 15}$$

Where Q is the quarter that credits were generated starting in Q1 of 2011, and β coefficients are estimated parameters, The CI_{20xx} is the carbon intensity standard in a given year, and ϵ is the error term associated with the regression.

A summary of the off-road credit generating sources staff modeled, and methods applied to estimate credits that may be generated by these sources is provided below:

1. Fixed Guideway, where future credit quantities were estimated using the above regression analysis to predict credit quantities for each quarter
2. Forklift – Credit quantities are based on historical reported data through 2022. The growth of forklift electricity are then adjusted after the implantation which includes an initial decrease due to the introduction of the metering requirement and a reduction of the EER to 1.9 for forklifts <12,000 lbs as well as the growth of forklifts >12,000 lbs.
3. Ocean Going Vessels (shorepower) – growth factor identified for container/reefer ships in OGV Regulation applied to 2022 credit totals. Credit values are frozen in 2032 when 100 percent of OGV are expected to use shorepower or other capture methods.
4. eCargo Handling Equipment – staff froze credit values at 2022 quantities.
5. eTransport Refrigeration Units – modeled credit quantities using a regression analysis of change in credit levels 2017-2022 until 2030 as indicated above, then frozen at 2030 quantities

Hydrogen

Low-carbon hydrogen production is likely to gain access to 45(V) tax credits under the Inflation Reduction Act. This likely includes $3 per kg for electrolytic hydrogen produced using zero-carbon electricity resources. For hydrogen produced using biomethane, Argonne GREET.NET pathways for animal manure and for landfill gas were used to estimate the 45(V) incentive value. Table 15 shows the incentive values that are assumed to be representative of 45(V) eligibility determinations.

Table 15. Estimated tax incentive from the IRA for low-carbon hydrogen production

Pathway	Hydrogen Tranche (kg CO_2e/kg-H_2)	Estimated IRA Incentive ($/kg)	Exogenous Subsidy used ($/MJ)
Animal Manure	< 0.45	$3	$0.025
Landfills	0.45 to 1.5	$1	$0.0083
0-CI Electrolytic Hydrogen	< 0.45	$3	$0.025
NG SMR w. CCS	2.5 to 4.5	$0.6	$0.005

Renewable Natural Gas

Renewable natural gas that is used to fuel natural gas vehicles is eligible for generating D3, cellulosic RINs. It was assumed that D3 RINs were valued at $3 per RIN, translating to an exogenous subsidy of $0.037 per MJ of RNG used in the CNG fuel pool.

Alternative Jet Fuel

There is limited commodity market data for alternative jet fuel, so the renewable diesel process economic values were taken as a proxy for production (alternative jet fuel is a co-product of renewable diesel production). Renewable diesel and biodiesel process costs were calibrated with market price data (discussed above). Market data used to derive production costs is believed to capture existing tax incentives tied to the tax code. Incentives due to the federal RFS are independently captured by RIN prices in the RIN market. Recently adopted provisions from the Inflation Reduction Act creates an additional blending incentive for alternative jet fuels in IRS tax code section 45(Z) that goes beyond the incentives to use and blend biomass-based diesel fuel. This incentive starts at $1.25 per gallon and provides an additional 1-cent incentive for every percentage point of carbon intensity reduction beyond a 50-percent reduction from conventional aviation fuel. Carbon intensities for the purpose of the 45(Z) tax credit were determined using Argonne's GREET aviation model.[33] The estimated incentive per gallon of alternative jet fuel is shown below.

[33] https://greet.es.anl.gov/greet_aviation

Table 16. Estimated tax incentive from the IRA for alternative jet fuel

Fuel	GREET Aviation CI	% Diff	Estimated IRA Subsidy ($/gallon)
Conventional	84.53	0%	NA
Soybean Oil	42.13	-50%	$1.25
UCO	11.4	-87%	$1.61

Note: the CI values shown in this table are not necessarily consistent with the CI values CARB may calculate for fuel under the Low Carbon Fuel Standard and are solely used for estimating federal incentives.

Because the existing blender's tax credit of $1 per gallon of renewable diesel was already captured by the estimated process economics for renewable diesel, only the additional subsidy beyond what renewable diesel would receive is incorporated into the model ($0.25 per gallon and $0.61 per gallon for virgin oil and waste oil respectively).

Summary of Example Scenario Changes

This section highlights the major changes that were made to the example scenario relative to the scenario that was posted to the CARB website in March, 2023.[34]

1. Energy demand from HDV and MDV stocks was adjusted to reflect vehicle electrification trends anticipated to occur due to Advanced Clean Fleets.

2. Out-of-state biomethane supply has been added for landfill gas and dairy gas.

3. LCFS annual benchmark schedules were updated to reflect discussions around a step-down.

4. Alternative jet fuel cost estimates have been updated.

    Because AJF is often a co-product of RD production, regression analysis was updated to predict AJF prices relative to the price of RD.

5. Estimation of credit generation for various off-road electrification pathways were added and updated:
    - Fixed Guideways
    - Forklift credit quantities
    - Ocean Going Vessels
    - eCargo Handling Equipment

[34] https://ww2.arb.ca.gov/sites/default/files/2023-03/scenario_inputs_30x30_90x45.xlsx

- eTransport Refrigeration Units

6. HDV and MDV VMT were adjusted to calibrate 2022 fuel supply estimates with 2022 LRT data.

7. Credit Bank Draw Down has been endogenized into the model by allowing for credits to be added for compliance purposes at credit prices equal to the credit price ceiling ($221.67, the 2021 calculated maximum credit price).

8. Pathway Carbon Intensities were updated to allow CCS for ethanol blended to make E85.

9. Carbon Intensity values for ULSD and Gasoline have been updated to reflect changes in benchmark CI.