California Transportation Supply (CATS) Model – Technical Documentation

CALIFORNIA
TRANSPORTATION
SUPPLY
MODEL (CATS)

Contents

Introduction

The California Transportation Supply (CATS) Model 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 a reference 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). 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:

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

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

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

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

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.

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

Preliminary Model 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 reference scenario, 8 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 pool

If a scenario is feasible, the model will determine the lowest cost mixture of fuel for each of the 8 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 ($S_{LDV,G}$) and medium-duty ($S_{MDV,G}$) vehicles and the off-road gasoline fuel demand ($D_{PW,G}$) outputs from the Proposed Scenario in the CARB 2022 Draft Scoping Plan Update.[3]

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] The EMFAC 2007 light-duty vehicle categories[5] and EMFAC 2007 medium-duty vehicle[6] categories were used for classifying vehicle characteristics to calculate these averages.

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[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] LDA, LDT1, and LDT2

[6] LHDT1, LHDT2, MDT, MH, OBUS, SBUS, and UBUS

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

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 reference 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.[7]

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 non-transportation diesel fuel demand ($D_{PW,D}$) outputs from the Proposed Scenario in the CARB 2022 Draft Scoping Plan Update. The total diesel fuel pool demand (D_D) was determined using Equation 10, where VMT_{HDV}, 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 diesel-consuming vehicles.[8] The vehicle weight categories for energy aggregation used the EMFAC 2007 heavy-duty vehicle classification (HHDT) and EMFAC 2007 medium-duty vehicle classification.[6]

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

Compressed Natural Gas Fuel Pool

Compressed natural gas energy demand is assumed to follow projections in the Proposed Scenario of the 2022 Draft 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

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

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

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. 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 electric vehicles were taken from the Proposed Scenario of the 2022 Draft Scoping Plan Update. 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.

Intrastate Jet Fuel

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

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.[9,10] For analysis, virgin feedstocks consist of soybean oil, corn oil, canola oil, and white grease. Waste feedstocks were assumed to consist of tallow 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

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[9] https://www.eia.gov/biofuels/biodiesel/production/
[10] https://www.eia.gov/biofuels/update/

percent change in supply for feedstocks relative to a percent change in the market price of biodiesel. Coefficient estimates using this methodology are shown below.

$$\ln (S_{0,i}) = \alpha + \beta \times \ln (C_{BD}) + \in \qquad \text{Equation 11}$$

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)	1408058	361325	361325	361325	361325	361325	361325	361325	
Incremental Virgin Oil (tons)	4524952	309035	309035	309035	309035	309035	309035	309035	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.[11] Costs were estimated for both dairy gas that is converted to renewable natural gas suitable for pipeline injection 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 dairy gas supply that can be injected into pipelines at below $40 per MMBtu is assumed to be more economical to use than a fuel cell, and is therefore allocated to the RNG feedstock supply curve for this model. At costs above $40 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.

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

Assumptions affiliated with the capital costs for fuel cells are detailed in the section discussing *Renewable Natural Gas-to-Fuel*.

Table 3. Estimated Dairy Gas Supply Curve

Cost ($/MMBTU)	30	40	50	75	90	100	125
Incremental Dairy Gas to RNG (MMBtu)	2801212	3892104					
Incremental Dairy Gas to Electricity (MMBtu)	0	0	7782698	2448129	14306	1039	420

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.[12]

Landfill Gas

The supply curve for landfill gas was taken from Jaffe et al. (2016). This supply curve suggests that almost 32 billion cubic feet of supply might be available at costs under $10 per MMBtu.

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 4 below.

[12] https://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf

Table 4. 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 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 5 below. 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 5: 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[13] relevant to the biomass-based diesel production process.

Table 6. 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

Renewable Gasoline and Sustainable Aviation 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[14], 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 sustainable aviation fuel (SAF). This price is assumed to be associated with SAF produced from virgin oils. Regression was used

[13] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx
[14] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-18284rev1.pdf

to estimate the yields and fixed costs for producing SAF using virgin oils. Because there were no data available to estimate the cost of producing SAF using waste oils, the waste oil production pathway was estimated using RD production cost information. The fixed cost and yield estimates for SAF using virgin oils were compared to renewable diesel, and this ratio was used to scale costs and yield estimates for SAF production from waste oil. For this assumption to hold, process factors would have to scale linearly for fractionating between SAF and RD when using waste oil compared to virgin oils.

Table 7 shows the estimated fixed costs and estimated yield for renewable gasoline and sustainable aviation fuel. Carbon intensities are assumed to be identical to the CI values for renewable diesel.

Table 7. Estimating fixed costs and yields for renewable gasoline and sustainable aviation fuel.

Technology	Estimated Fixed Costs ($/ton)	Estimated Yield (MJ/ton)
RG Virgin Oil	$905	38878
RG Waste Oil	$1,102	37655
SAF Virgin Oil	$633	32552
SAF Waste Oil	$776	31528

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).[15]

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 for conventional fuels, ultra-low sulfur diesel and CARBOB prices (C_{conv}) relative to West Texas Intermediate crude oil prices (C_{oil}).

$$C_{conv} = \alpha + \beta \times C_{oil} + \epsilon \qquad \text{Equation 13}$$

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

Table 8. 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 11. 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.[16] This resulted in fixed cost estimates of $0.17 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[17], 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

Table 9. Estimated costs and yields for ethanol production technology

Technology	Estimated Fixed Costs ($/bu)	Estimated Yield (MJ/bu)
Ethanol	$0.17	235
Ethanol with CCS	$0.59	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.

[16] 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

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

CNG and Renewable Natural Gas-to-Fuel

Compressed natural gas (CNG) fuel costs from the Alternative Fuel Data Center[18] (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.[19] 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 10 below shows how this translates into an assumed grid-average carbon intensity for modeling.

Table 10. Estimated Grid Average Electricity CI through 2045

Year	Alt 3 Scoping Plan CI Relative to 2021	Estimated Grid-Avg CI
2022	100%	76.73
2023	91%	69.50
2024	90%	69.18
2025	90%	68.75

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

Year	Alt 3 Scoping Plan CI Relative to 2021	Estimated Grid-Avg CI
2026	84%	64.21
2027	78%	59.55
2028	72%	55.60
2029	67%	51.50
2030	62%	47.78
2031	61%	47.03
2032	60%	45.97
2033	58%	44.83
2034	57%	43.52
2035	55%	42.18
2036	52%	40.23
2037	50%	38.51
2038	48%	36.80
2039	46%	35.38
2040	44%	33.88
2041	42%	32.49
2042	41%	31.26
2043	39%	30.02
2044	37%	28.76
2045	36%	27.65

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.[20] 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 Draft 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 $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 11. References for hydrogen production process assumptions

Pathway	Cost Assumptions	Carbon Intensity Assumptions
H_2 from fossil NG	NREL Hydrogen Analysis Production Model [21]	LCFS lookup table
H_2 from fossil NG + CCS	NREL Hydrogen Analysis Production Model	Discussion below

[20] https://burbank.granicus.com/MetaViewer.php?view_id=2&clip_id=8917&meta_id=363607
[21] NREL 2018. "H2A: Hydrogen Analysis Production Models." https://www.nrel.gov/hydrogen/h2a-production-models.html.

Pathway	Cost Assumptions	Carbon Intensity Assumptions
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 (Mac Kinnon 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 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) [22], but also break out the cost components (Table 12) so that the cost of conversion, without feedstock costs, can be estimated. NREL cost estimates are in 2016 dollars, which can be converted to the present year 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.

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

Table 12. 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[23] of 117.67 g CO_2e/MJ (HYF pathway), with fossil natural gas feedstock replaced with dairy biomethane.

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.

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

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). [24] 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.[25]

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 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.

[24] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-05.pdf
[25] https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf

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 Mc Kinnon 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 13 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 (Mac Kinnon 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 13. 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 RINs 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. This translates into an exogenous subsidy of $0.017 per MJ of biodiesel and $0.019 per MJ of renewable diesel used in California.

Ethanol and Ethanol with CCS

Corn-based ethanol is eligible to generate D6 Renewable Identification Numbers (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 costs 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.

Sustainable Aviation Fuel

There is limited commodity market data for sustainable aviation fuel, so the renewable diesel process economic values were taken as a proxy for production (sustainable aviation 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 sustainable aviation fuels in IRS tax code section 45(B) 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 were determined using Argonne's GREET aviation model[26]. The estimated incentive per gallon of sustainable aviation fuel is shown below.

Table 14. Estimated tax incentive from the IRA for sustainable aviation 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).

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.

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