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2030 CALIFORNIA RENEWABLE NATURAL GAS OUTLOOK: RESOURCE ASSESSMENT, MARKET OPPORTUNITIES, AND ENVIRONMENTAL PERFORMANCE

Jane O'Malley, Nikita Pavlenko, Yi Hyun Kim

www.theicct.org

communications@theicct.org

twitter @theicct

icct
THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION

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Edited by Amy Smorodin

International Council on Clean Transportation
1500 K Street NW, Suite 650
Washington, DC 20005

communications@theicct.org | www.theicct.org | @TheICCT

EXECUTIVE SUMMARY

The use of renewable natural gas (RNG) in the United States has grown rapidly over the past decade, largely due to federal and state policy incentives that subsidize its use in heating, power, and transportation. Within the transportation sector, fleet operators and jurisdictions have made significant investments in, and purchase commitments for, natural gas-fueled vehicles with the intent of fueling them with RNG. Prominent heavy-duty vehicle manufacturers have also lobbied for allowing natural gas vehicles to count towards the California's ultra-low nitrous oxide (NO_x) requirements. Despite the relatively small size of the natural gas fleet in California, RNG has grown to become one of the largest methods of compliance within California's Low-Carbon Fuel Standard (LCFS).

This paper provides an assessment of RNG's potential as a low-carbon fuel in California in 2030, considering its resource availability, production cost, and climate performance. We estimate the possible production volume of cost-viable RNG, defined as projects that achieve a break-even net present value over a ten-year crediting period. Although our baseline calculations assume an extension of LCFS policy support, we also consider the impact that changes to California methane regulations may have on future levels of RNG-crediting under the LCFS. We find that, relative to other heavy-duty fuel technologies, the use and support of RNG has several drawbacks.

Renewable natural gas can be expensive, and its potential supply is limited. Cost-viable volumes of RNG could displace, at most, 8.9% of heavy-duty fuel demand in California in 2030. Slightly less than half of California's maximum RNG resource potential can be achieved in 2030 with the current set of incentives, as shown in Figure ES1. In-state dairy RNG exhibits the lowest growth potential of all pathways because its production is nearly maximized. For RNG that is injected into the natural gas pipeline network, cost-viable volumes could displace 5.2% of statewide gas demand.

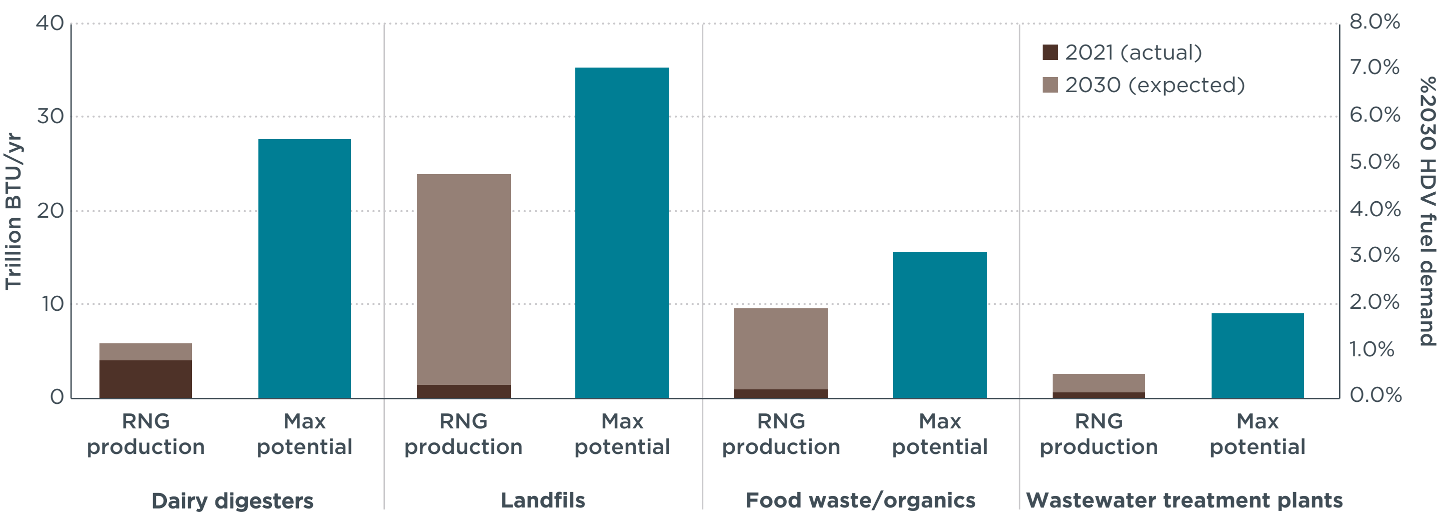

Figure ES1. Renewable natural gas production and maximum potential relative to California heavy-duty vehicle fuel demand

The life-cycle emission reduction benefits of RNG may be overstated due to outdated assumptions. Many RNG pathways certified under the California's LCFS are assigned a low or negative life-cycle emissions value based on the assumption that methane emissions are avoided when biomethane is upgraded to transportation fuel rather than left uncaptured at the source. However, ongoing revisions to California's climate policies, including a 40% reduction target in statewide methane emissions by 2030, may require biomethane producers to reduce these emissions anyway. Taking this into account, we find that dairy RNG would release 30-40 grams of CO_2-equivalent per megajoule, which is around half of the life-cycle GHG emissions of natural gas.

Updating California's carbon accounting would increase the competitiveness of in-state RNG producers. Changing the credit calculations in the LCFS to account for the state's methane reduction policies would reduce the potential of cost-viable RNG produced outside California but would not significantly affect the economics of in-state RNG production. It also would not impact landfill gas projects and small-scale farms that treat waste in pasture or solid storage applications because the current carbon accounting method for these pathways does not assume high methane emissions in the absence of RNG production.

Natural gas vehicles will not deliver significant climate benefits over diesel. We estimate that a natural gas tractor-trailer will generate, at most, approximately 11% lifetime GHG savings relative to a diesel tractor-trailer, even when assuming California achieves its maximum in-state RNG potential, as shown in Figure ES2. The figure displays the lifecycle GHG emissions over the lifetime of a tractor-trailer powered by diesel, compressed natural gas (average California gas mix), and electricity (average California electricity grid mix). We estimate that a battery-electric tractor-trailer generates approximately 57% GHG savings over its lifetime compared to a diesel tractor-trailer, based on the projected change in California's electricity grid intensity over time.

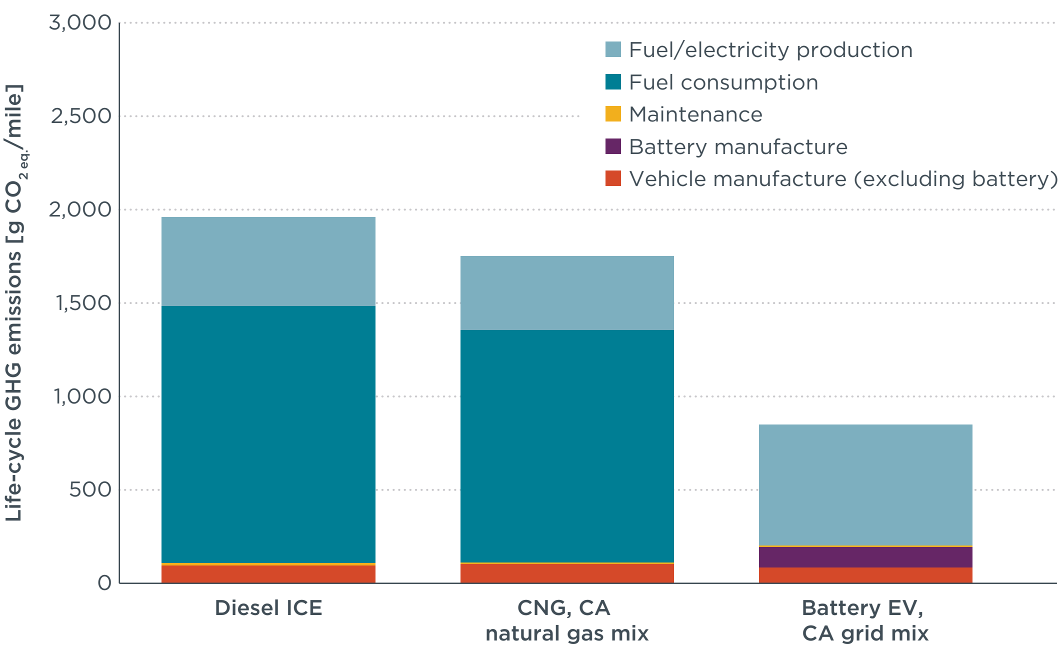

Figure ES2. Comparison of vehicle lifetime emissions for conventional, diesel-fueled truck, a CNG truck fueled by the California gas mix, and a battery electric truck fueled by the California electricity grid mix.

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LIST OF ACRONYMS

AD	Anaerobic digestion
BEV	Battery electric vehicle
CARB	California Air Resources Board
CDFA	California Department of Food and Agriculture
CPUC	California Public Utilities Commission
CI	Carbon intensity
CNG	Compressed natural gas
DGE	Diesel gallon equivalent
GHG	Greenhouse gas
HDV	Heavy-duty vehicle
LFG	Landfill gas
LCA	Life-cycle assessment
LCFS	Low-carbon fuel standard
MCF	Million cubic feet
MMBTU	Million British thermal units
NGV	Natural gas vehicle
NPV	Net present value
RNG	Renewable natural gas
SB	California Senate Bill
SLCP	Short-lived climate pollutant
WWTP	Wastewater treatment plant

INTRODUCTION

The majority of renewable natural gas (RNG) produced in the United States today comes from biogas, which is a mixture of methane, carbon dioxide, and trace compounds such as hydrogen sulfide (U.S. Environmental Protection Agency, 2020). Once impurities are removed, biogas can be used as a fuel source in heat and power applications. The primary sources of RNG in the United States include landfill gas, livestock manure, wastewater sludge, and organic waste such as food waste. Figure 1 displays the current sources of RNG produced in California and the United States overall by share of total production (Argonne National Laboratory, 2022). In California, the majority of RNG produced in-state is generated at dairy manure facilities whereas, across the rest of the United States, more than 70% of RNG is produced at landfills.

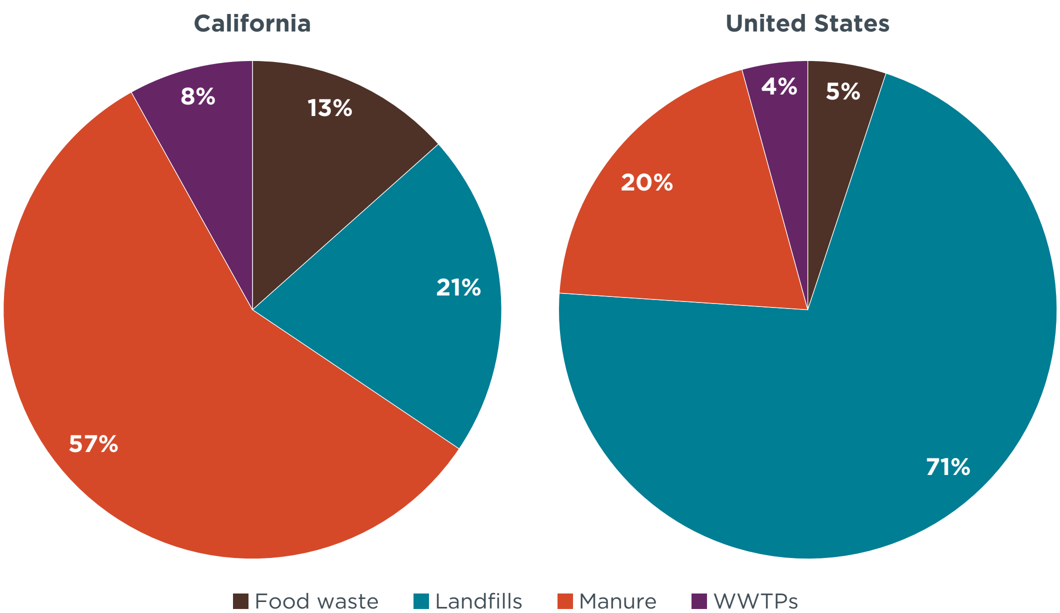

Figure 1. Overview of RNG resources in California and the United States

Biogas and its finished products can be used in various applications both within and outside the fuels sector. Biomethane, produced by removing carbon dioxide from biogas, can be compressed and consumed onsite to fuel trucking fleets or blended as RNG with natural gas in transmission pipelines. Outside the fuels sector, biomethane can be burned to generate electricity that is consumed onsite or sold to the regional power grid. Electricity generation is the most common application for landfill biogas today, accounting for 71% of its final end uses in California (U.S. Environmental Protection Agency, 2016b). Electricity is a lesser-used application for livestock digester projects and accounted for 23% of biogas end uses across the United States in 2021 (U.S. Environmental Protection Agency, n.d.-b). Comparatively, RNG made up 2%–4% of end uses for biogas generated at landfills and 68% of end uses for biogas generated at livestock digesters in California, according to data compiled by the U.S. Environmental Protection Agency (EPA). Biogas that is not used in electricity and transport applications is either flared or used in cogeneration and direct heating applications.

The consumption of biomethane in transport applications has grown substantially over the last ten years, bolstered by strong policies and industry investment. Natural gas vehicles (NGVs) make up a small share of the U.S. medium and heavy-duty vehicle market and account for approximately 0.8% of registered vehicles

(Lowell & Culkin, 2021; U.S. Department of Energy, n.d.). However, interest in NGVs is growing as truck manufacturers look toward alternative technologies to meet tightened greenhouse gas (GHG) and air quality standards. The South Coast Air Quality Management District has invested in over 130 compressed NGVs to replace its outdated diesel fleet and reduce localized air pollution (White et al., 2019). As of 2020, more than half of WM's fleet of 20,000 vehicles have been converted to run on compressed natural gas (CNG) (WM, 2022). Natural gas can also be liquefied to increase its energy density, making it suitable for fueling long-range Class 7 and 8 trucks (Brecher et al., 2015) To date, liquefied natural gas trucks have not been widely deployed due to additional vehicle technology and infrastructure requirements needed to store fuel at cryogenic temperatures.

The significant growth in RNG markets has been met with pushback from some stakeholders. The environmental justice community has raised concerns about the environmental and health impacts of RNG, such as its potential effects on groundwater contamination, air pollution, and factory farm consolidation (Lazenby et al., 2021; Public Justice, 2021). Stakeholders participating in the California Air Resources Board (CARB) Dairy and Livestock Greenhouse Gas Emissions Working Group have argued that managing manure in anaerobic digesters rather than applications typically reserved for small farms, such as pastures or solid storage, could incentivize higher levels of methane production (California Air Resources Board, 2018b). Academics and public interest groups have also raised the possibility of RNG being over-credited with GHG reductions within California's state-level fuels policy, particularly as farms respond to separate climate policies and methane standards (Grubert, 2020).

This study assesses the current role of RNG as a transport fuel in California and provides a 2030 outlook for RNG relative to other vehicle technologies and end uses. We evaluate RNG's resource potential, cost, and climate performance in the context of existing policies and impending regulations that may change our understanding of RNG's lifecycle climate benefits.

FEDERAL AND STATE POLICY INCENTIVES FOR RENEWABLE NATURAL GAS

In the United States, RNG production costs are substantially offset by federal and state policy incentives. California's Low Carbon Fuel Standard (LCFS) program has incentivized growth in RNG projects both inside and outside the state, resulting in an uptick in RNG fuel crediting in recent years (CARB, 2021). The LCFS is designed to reduce the carbon intensity (CI) of California's transportation fuel mix. Under the LCFS, RNG producers can generate credits for fuel with lifecycle emissions lower than the GHG intensity standard, with the exact quantity of credits based on the GHG intensity of the specific RNG pathway. Although RNG must be sold in California to receive LCFS credits, fuel producers can be located anywhere in the country and receive credits via book-and-claim accounting, a chain of custody model that tracks the exchange of environmental attributes without physical traceability (Nielsen, 2021). Producers of RNG are also granted a ten year crediting guarantee, locking in their assessed GHG intensity following certification (California Senate Bill No. 1383, 2016),

The California LCFS currently offers the highest incentives for RNG production of all state-level clean fuel programs. The pathway with the lowest certified CI received up to $16.79 per diesel gallon equivalent (DGE) in LCFS credits in 2021 (California Air Resources Board, 2021), nearly thirty times the wholesale cost of natural gas in the United States that same year (U.S. Energy Informaiton Administration, n.d.) The average 2021 credit value across all certified RNG pathways was considerably lower at $2.70/DGE. Of all feedstock pathways, dairy digesters receive the highest level of policy support. This is because methane is assumed to be vented in the absence of biofuel production. CARB has estimated that LCFS credits provide $865,000 in annual revenue to a typical livestock farm (Lee & Sumner, 2018). On average, an estimated 93% of dairy digester project revenue is attributed to policy incentives while the remainder is attributed to direct fuel sales (Lee & Sumner, 2018).

Regulatory implementation of the state's short-lived climate pollutant (SLCP) reduction strategy via SB 1383 will likely require biogas producers to capture methane at the source or prevent methane-intensive manure management practices altogether (CARB, 2017b). Thus, avoided methane emissions currently credited to RNG producers under the LCFS may soon overstate the fuel's decarbonization potential. SB 1383 requires a 40% reduction in statewide methane emissions from a 2013 baseline by 2030. As of 2019, methane emissions associated with manure management had only been reduced by 1% (CARB, 2021a).

The federal Renewable Fuel Standard (RFS) program includes another credit mechanism that can incentivize RNG production; the RFS obligates U.S. petroleum refiners and importers to purchase a specified quantity of renewable fuel each year to reduce reliance on petroleum transportation fuel. RNG is eligible to generate RFS credits, known as Renewable Identification Numbers (RINs), under the cellulosic biofuel category ("D3"). Credits under category D3 have consistently traded at the highest price of all eligible renewable fuels over time, fluctuating between $0.80 and $5.60 per DGE since 2017 (U.S. Environmental Protection Agency, 2022).

In addition to market-based incentives, various federal grant programs are in place to offset the capital costs of biomethane projects. California also provides grants and loans to fund RNG projects as part of its Climate Investment programs (About California Climate Investments, n.d.). A summary of grant programs and funding streams provided in Table 1.

Table 1. Overview of federal and state digester financing schemes

Program	Description	Funding details
USDA Rural Energy for America Program (REAP)	• Provides loan financing and grant funding to agricultural producers and small rural businesses • Funding for renewable energy systems such as anaerobic digesters and the purchase, installation, and construction of energy efficiency improvements	• Loan guarantees up to 75% of total eligible project costs • Grants up to 25% of total eligible project costs • Combined grant and loan guarantee up to 75% of total eligible project costs • Renewable Energy System Grants: $2,500–$500,000 • Energy Efficiency Grants: $1,500–$250,000
USDA Value-Added Producer Grants (VAPG)	• Helps agricultural producers adopt value-added activities to generate products, expand marketing opportunities, and increase income • Entities that build, manage, and operate anaerobic digesters are eligible for the program	• Total available funding: $19.75 million • Maximum grant amount: $75,000 for planning grants and $250,000 for working capital grants
DOE Clean Cities Coalition	• Promotes environmental security by leveraging local projects to reduce petroleum usage in transportation • Provides funding and technical expertise to at least seven operating RNG projects	• More than $490 million in funding has been awarded to energy efficient and alternative vehicle fuel projects since 1998
CPUC Biomethane Interconnector Monetary Incentive Program	• Encourages development of biomethane projects interconnected to gas pipeline systems • Dairy cluster projects allowed to include gathering line costs as qualifying interconnection expense	• Maximum funding: $3 million per project and up to $5 million for dairy cluster projects • Incentive available until 2026 or until the program has exhausted its $40 million cap
CDFA Dairy Digester Research and Development Program	• Provides financial assistance for dairy digester installations in California • Program part of California Climate Investments	• $80 million in state funding allocated for FY 2021-2023 • $195 million in funding awarded since 2014
CalRecycle Greenhouse Gas Reduction Loan Program	• Provides incentives for supporting new or expanded organics infrastructure (i.e., composting, anaerobic digestion facilities) • Program part of California Climate Investments	• Available funds (FY 2021–2022): $2,500,000

Sources: California Public Utilities Commission (n.d.), California Department of Food and Agriculture (2022), CalRecycle, (n.d.), Rural Business-Cooperative Service and Rural Utilities Service, USDA (2015), SoCalGas (n.d.), U.S. EPA (2021), USDA Rural Development (n.d.-a), USDA Rural Development (n.d.-b), Mintz, (2015)

Relative to other U.S. states, California has high pipeline interconnection costs, in addition to stringent fuel specification and testing requirements (Jaffe et al., 2016). To offset these costs, the California Public Utility Commission (CPUC) Biomethane Interconnector Monetary Incentive Program offers project funding capped at $5 million for dairy clusters and $3 million for all other projects (CARB, 2017b). This has led to the formation of dairy biogas “clusters,” or digester projects that pool together organic waste resources to generate biogas at a central digester (CARB, 2017b). RNG producers may also circumvent California interconnection fees via book-and-claim accounting. In simpler terms, RNG production and consumption are decoupled so that producers injecting fuel into pipelines out-of-state may match these volumes with fuel consumed in-state.

Book-and-claim accounting provides added flexibility for producers but does not guarantee that fuel produced out-of-state is delivered to California customers or consumed in the transportation sector. In contrast, low-carbon electricity producers have more stringent deliverability requirements and must be located within the Western Interconnection system to qualify for electricity and hydrogen LCFS credits (CARB, 2019b). Of the roughly 200 million GGE of RNG credited under the LCFS in 2021, only 31% was produced in California (Argonne National Laboratory, 2022; California Air Resources Board, n.d.). Mazzone et al. (2021) found that the volume of RNG produced out-of-state and credited under the LCFS increased more than 140% between 2010 and 2019.

Figure 2 illustrates the shift in RNG feedstock volumes credited under the LCFS over time in California. Landfill-derived RNG volumes have quickly surpassed consumption of fossil based RNG. Over the last two years, RNG crediting from livestock manure pathways grew more than six-fold. Between 2016 and 2021, RNG volumes credited in California grew nearly five-fold. As of 2021, credited RNG volumes met demand for all fossil natural gas consumed by the California vehicle sector (CARB, 2022).

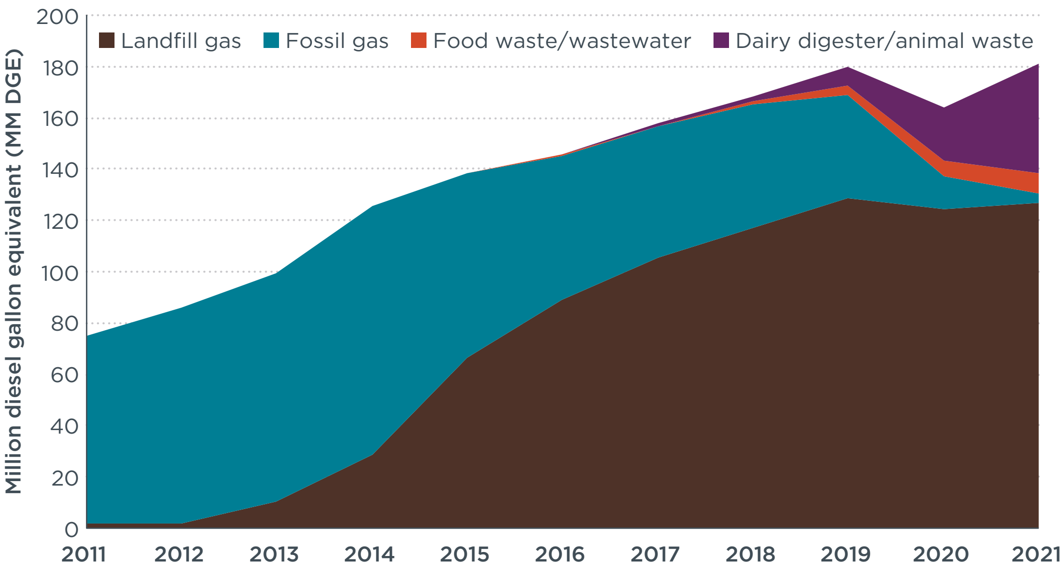

Figure 2. Volumes credited under the LCFS by RNG feedstock pathway.

The availability and climate impacts of RNG will play an important part in determining its future role in decarbonizing the transportation sector. Even though natural gas does not qualify under the state's Advanced Clean Trucks (ACT) rule, which mandates an increasing share of zero-emission truck sales through 2035 (Advanced Clean Trucks Regulation, 2019), it continues to play an outsized role under the LCFS.

METHODOLOGY

The following sections present the methodology used for the three primary parts of this analysis. First, we present the methodology used to assess the RNG supply in California, comparing the current use and maximum theoretical availability of RNG from livestock manure, landfill gas, wastewater sludge, and food waste. Next, we present methods used to evaluate the cost of supplying RNG from these different sources, estimating the cost-viable, in-state production potential in California. Lastly, we present the methodology used to determine the life-cycle climate impacts of different sources of RNG in California and the impact of potential revisions to the estimated GHG intensity of RNG on its policy value and its impact on truck emissions.

RESOURCE ASSESSMENT

Various studies have assessed biomethane resource potential in the United States. A 2013 National Renewable Energy Laboratory analysis of U.S. biogas potential from animal manure, landfill gas, organic waste, and sewage sludge estimated that the United States could produce up to 7.86 million tonnes (Mt) of methane from these resources per year, equivalent to 3.0 billion DGE of vehicle fuel (NREL, 2013). In a subsequent analysis, Saur and Milbrandt (2014) estimated the total biomethane potential in the United States to be roughly 6.1 billion DGE, and its availability to be 2.4 billion DGE. Hamberg et al. (2012) estimated that RNG produced from anaerobic digestion of livestock, sewage sludge, and landfill gas could produce roughly 3.9 billion DGE per year, and that the thermal gasification of biomass feedstocks such as agricultural and forestry wastes could produce an additional 30.4 billion DGE.

Several RNG resource assessments have also been conducted for California. A feasibility study conducted by Jaffe et al. (2016) summed the availability of landfill gas, anaerobically digested dairy manure and food waste, and gasified biomass. At 2015 federal RIN and state LCFS credit prices, the authors estimated that more the 80 billion cubic feet per year (642 million DGE) of RNG could be produced at a competitive cost. In an earlier study, researchers at UC Davis estimated that biomethane resource potential in California was 93 billion cubic feet per year (721 million DGE) (Williams et al., 2015). Unlike Jaffe et al., this study was focused on the power sector and utilized coarser data sources to calculate resource estimates. ICF International conducted a more recent estimate of both maximum and feasible RNG resource potential in the United States in a report prepared for the American Gas Foundation (2019). For the Pacific region, including the states of California, Washington, and Oregon, RNG resource potential ranged between 1,014 and 1,713 million DGE for the same feedstocks included in this analysis. Gladstein and Couch (2020) performed market-based research to project RNG production in California in 2024. The authors only included existing projects or those under development, so it reported a significantly lower resource estimate of 119 million DGE.

We perform our own analysis to estimate the total biomethane potential in California, using many of the underlying resources cited in Jaffe et al. (2016). These estimates assume that all biomethane resources in the state are utilized as RNG at 100% capture efficiency rather than consumed in other end-use applications. Our calculations for each fuel pathway are described in further detail in the subsequent sections.

For each resource pathway, we also collect data on current RNG production from a database compiled by Argonne National Laboratory to compare theoretical potential with current supply (Argonne National Laboratory, 2022). This database includes information on facility name and location, digester capacity, biogas flow rates, and volumetric output. As of 2021, the database identified a total of 230 operational projects in the United States that produce 74 billion cubic feet of RNG per year, equivalent to 574 million DGE. This volume rises to 735 million GGE when including planned projects that are not yet operational. We find that California makes up roughly 7% of current RNG production in the United States, including nearly a quarter of RNG from livestock manure.

Livestock manure

Biomethane derived from livestock manure is produced during the natural decomposition of organic material. Dairy cattle have higher methane generating potential than other livestock types due to their digestive properties and quantity and makeup of feed intake (Mangino et al., n.d.). We focus on biomethane potential solely from dairy cattle manure for this analysis, the only source of manure-derived RNG in California today. California has a small swine industry with limited resource potential relative to other U.S. states and is thus excluded from our analysis. We also exclude poultry farms from our resource assessment due to their use of dry manure management systems and poultry manure's high nitrogen content which inhibits methane production (Einarsson & Persson, 2017; U.S. Environment Protection Agency, 2018).

The quantity of potential RNG generation from dairy manure depends greatly on the herd size and manure management practices at a given farm. Managing manure in an anaerobic environment has the highest methane conversion factor, or rate of methane produced per theoretical methane yield. Manure generated at large farms has historically been processed using anaerobic lagoons, which are large storage systems that break down manure at ambient temperatures (Hamilton, 2017). Anaerobic digesters that regulate flow rates and temperature can also be used and provide water quality and land conservation benefits relative to lagoons (U.S. Environmental Protection Agency, 2018). Manure produced at smaller farms is typically allowed to decompose aerobically and produces less methane than their anaerobic counterparts (Dong et al., 2006).

For this resource assessment, we estimate the quantity of biomethane that could be produced from dairy manure processed in anaerobic digesters in California using methodology adopted from the Intergovernmental Panel on Climate Change's Tier 1 formulas for emissions from livestock and manure management (Dong et al., 2006). We also source state-specific emissions factor data from California Air Resources Board (2014). Methane production at livestock operations is a function of several parameters: the total weight of cows on a farm (TAM), volatile solids excretion rate (VS_L), methane conversion factor (MCF), ambient temperature, and methane generation rate per unit of volatile solids (B_0). Factors for these parameters are adopted from CARB's Compliance Offset Protocol for Livestock Projects document (CARB, 2014). We draw data on the number of dairy cattle heads in the state from the National Agricultural Statistics Service (USDA NASS, 2021). We calculate the maximum methane production of California's dairy farm industry by inputting parameter data into Equation 1.

Equation 1. Calculation of methane production from livestock manure management

$$\textit{Methane production } (m^3) = TAM \times VS_L \times B_0 \times MCF$$

Landfill gas

We source data on landfill gas production rates from EPA's Landfill Methane Outreach Program database (U.S. Environmental Protection Agency, n.d.-c). This database compiles information on landfill gas facilities throughout the United States, including tons of waste in place, landfill gas collection and flaring rates, and corresponding end-uses (e.g., direct heating, gas turbine). We assume that all landfill gas generated in California could be upgraded to RNG and convert data reported in million standard cubic feet per day to million British thermal units (MMBTU) per year of biomethane. A summary of landfill gas (LFG) resources in California by current end use is included in Table 2 below.

Table 2. Summary of landfill gas production and end-uses in California.

Project Type	Annual output (million ft^3/year)	Annual output (trillion BTU/year)	Share of total
Electricity	41,622	24.9	71%
Cogeneration	3,530	2.1	6%
Direct heating	948	0.57	1.6%
RNG	1,267	0.76	2.1%
Flared	11,586	6.93	20%
Total	**58,954**	**35.3**	**100%**

Wastewater

We do not identify any publicly available data on process and flow rate at California's wastewater treatment plants (WWTPs). Jaffe et al. (2016) report that 43% of California's wastewater digesters captured biogas for productive use in 2016 and generated 4 billion cubic feet of biomethane. Using this information, we establish a proportional relationship to estimate maximum biomethane output from wastewater digesters if 100% of biogas was captured and upgraded to RNG to estimate the total theoretical potential. In practice, technical constraints, such as operational downtime and grit accumulation, will limit the amount of biogas captured at WWTPs (Water Environment Federation, 2017). California's WWTPs also vary in size, so a proportional relationship is a crude estimate of total theoretical potential.

Food waste

Like wastewater feedstocks, projections for maximum biomethane production potential from food waste is also more speculative due to uncertainty around future landfilling and waste management practices. Food waste management is also more decentralized than other RNG pathways and can be co-digested with other waste streams such as sewage sludge. To estimate maximum resource potential, we adopt a conversion factor of 2.16 MMBTU of biomethane per wet ton of digested food waste from Jaffe et al. (2016) and a mass estimate of projected tons of food waste generated in 2030 from a report commissioned by the California State Water Resources Control Board (Carollo Engineers, 2019).

COST ASSESSMENT

We assess the maximum biomethane resource potential in relation to cost-competitive volumes in 2030, calculated with and without avoided methane crediting. Volume projections that assume a policy scenario with avoided methane crediting are defined as "pre-regulation," while volume projections that assume a scenario with no avoided methane crediting are defined as “post-regulation.” For dairy digester and landfill gas projects, we perform a discounted cash flow analysis to determine a threshold for RNG projects that result in a breakeven project cost. We also compare the costs and revenue streams associated with pipeline RNG to its alternative uses, including converting biomethane to electricity that is sold to the power grid or claimed as energy for electric vehicle charging.

We define cost-competitive projects as those that achieve a breakeven net present value (NPV) over a 10-year period and 8% annual discount rate. We do not have complete project data for wastewater and food waste pathways, so we rely on estimates from our literature review to estimate cost-competitive volumes of RNG production.

Livestock manure

Breakeven project costs for dairy projects are a function of capital cost, operating costs, and project revenue. In turn, these values are a function of the number of dairy cow heads and manure management type. Capital costs and operations and maintenance costs for dairy manure digesters are calculated using formulas and assumptions published in Appendix F of CARB’s SLCP strategy document (CARB, 2017a). An overview of the input parameters used for our NPV calculations for digester RNG projects is included in Table 3. Capital and operating costs differ slightly between single and centralized digesters, known as cluster projects, that require additional equipment purchases to truck manure and adjusted upgrading costs to account for increased digester capacity. We assume that dairy digesters are located in rural areas that utilize lower-cost, low-pressure distribution pipelines. Rural projects also incur high interconnection fees, including land acquisition, permitting, and equipment upgrading costs (*AB 3187 (Grayson) - As Amended April 11, 2018*, 2018).

Table 3. Dairy biogas to pipeline RNG costs for single and centralized plug-flow digesters

Cost category	Capital expenses	Operation and maintenance expenses	Reference
Above-ground tank digester	(0.64 x 18,431 x [# dairy cattle])$^{-0.275}$ x [# dairy cattle]	6% of capital cost	CARB (2017a)
Pipeline	$200,000/mile	5% of capital cost	California Environmental Associates (2015)
Plant electric utilities		$0.07/kWh	U.S. Energy Information Administration (2022)
Plant diesel utilities		$3.86/gallon	Bourbon (2022)
Single digester			
Biogas upgrading		$8 per MCF biogas	CARB (2017a)
Interconnection fee	$2,000,000	5% of capital cost	California Environmental Associates (2015)
Centralized digester			
Biogas upgrading		$6 per MCF biogas	CARB (2017a)
Interconnection fee	$5,500,000	3.5% of capital cost	California Environmental Associates (2015)
Low-NO_x natural gas truck purchase	$250,000/truck	N/A	California Environmental Associates (2015)
Manure transport cost		$2/mile plus $15/trip	CARB (2017a)

Annual revenue from wholesale gas sales and policy incentives, including LCFS and RFS credits, help offset the capital costs and operations and maintenance costs associated with RNG production. We assume an average LCFS credit price of $100/metric tonne across the lifetime of RNG projects based on median historical credit prices. Renewable fuel credit values awarded under the RFS, referred to as Renewable Identification Numbers (RIN), are $2.65/gallon ethanol equivalent, which is the average D3 RIN price in 2021 (U.S. Environmental Protection Agency, n.d.-a). Wholesale biogas selling prices are drawn from Appendix F of CARB (2017a) and set equal to $3.46 per thousand cubic feet. We also review the breakeven project costs for biomethane utilized to generate electricity, a common application for existing dairy manure digester projects. Capital and operating costs for electricity projects, which are slightly different than for RNG projects, are summarized for both single and centralized digesters in Table 4.

Table 4. Dairy biogas to electricity costs for all plug-flow digesters

Cost category	Capital expenses	Operation and maintenance expenses	Reference
Above-ground tank digester w/ microturbine producing electricity	(18,431 x [# dairy cattle])$^{-0.275}$ x [# dairy cattle]	8.5% of capital cost	CARB (2017a)
Plant electric utilities		$0.07/kWh	U.S. Energy Information Administration (2022)
Plant diesel utilities		$3.86/gallon	Bourbon (2022)
Interconnection fee	$160/kW	5% of capital cost	Neff (2019)
Single digester			
Biogas upgrading		$6 per MCF biogas	CARB (2017a)
Centralized digester			
Biogas upgrading		$2 per MCF biogas	CARB (2017a)
Low-NOx natural gas truck purchase	$250,000/truck	N/A	California Environmental Associates (2015)
Manure transport cost		$2/mile plus $15/trip	CARB (2017a)

Dairy biogas that is later converted to electricity is also eligible for cap-and-trade offset credits and a biomethane feed-in-tariff of $0.1277/kWh for projects up to 5 MW in size (PG&E, n.d.). We assume a constant cap-and-trade credit price of $25 per metric tonne of CO_2e avoided. This value is near both the current trading price and credit floor price in 2030 (California Air Resources Board, 2017).

Once the breakeven project size is calculated for livestock facilities with and without existing digesters, we can determine the number of existing dairy farms in California that could support a cost-viable RNG project in 2030. The breakeven threshold is compared with the number of dairy cattle located at the 80 farms reported to be equipped with an anaerobic digester in California in EPA's AgSTAR database (U.S. Environmental Protection Agency, n.d.). We consider viable projects as those that have greater than the threshold number of cows and are not currently upgrading biomethane to RNG. We filter the AgSTAR database for projects that meet those criteria.

We consider farms that are not yet upgrading biogas to RNG but fall above the threshold to be cost-competitive, while farms that are not yet upgrading biogas to RNG but fall below the threshold to be cost-prohibitive. Dairy farms that are not equipped with an existing digester make up a small share of manure capacity but could, in theory, pool together resources to generate pipeline-injected RNG. All existing dairy manure RNG projects are assumed to continue operating through 2030.

Landfill gas

We apply a similar methodology as described above to calculate cost-viable RNG production from California landfills in 2030. We calculate a 10-year breakeven NPV using cost information provided in EPA's Landfill Energy Project Development Handbook (U.S. Environmental Protection Agency, 2016). Cost formulas and revenue streams for LFG projects are summarized in Table 5. The pipeline interconnection fees used in EPA's LFG cost modeling are much lower than the pipeline interconnection fees reported by CARB for dairy digester projects, but are still in the range of fees reported by project developers (CARB, 2017a; California Environmental Associates, 2015). This cost discrepancy may be explained by the siting of LFG projects; these projects are typically located in populated areas with infrastructure that requires fewer system upgrades. Because capital cost estimates are highly sensitive to this parameter, our analysis may overestimate the NPV of LFG projects.

Table 5. Landfill gas to pipeline RNG cost and revenue assumptions

Cost category	Capital expenses	Operation and maintenance expenses	Reference
Installed cost of gas processing equipment	$6,000,000 x $e^{0.0003*[LFG (ft3/min)]}$	$250 x [LFG (ft^3/min)] + $148,000	U.S. Environmental Protection Agency (2016)
Interconnection fee	$400,000	5% of capital cost	U.S. Environmental Protection Agency (2016)
Installed cost of pipeline to convey gas to project site (>1 mile)	$1,000,000/mile	5% of capital cost	U.S. Environmental Protection Agency (2016)
Plant electric utilities		$0.07/kWh	U.S. Energy Information Administration (2022)
Plant natural gas utilities		$3.16/MCF	U.S. Energy Information Administration (n.d.b)
Revenue category	Value		Reference
Biogas price	$3.46/MCF		CARB (2017a)
RIN credit price	$2.65/gallon ethanol equivalent		U.S. Environmental Protection Agency (n.d.)
LCFS credit price	$100/mt		Neste (2017)

We review project specific information from EPA's Landfill Methane Outreach Program database to determine the quantity of LFG from projects that meet the breakeven flow threshold and are not producing RNG today (U.S. Environmental Protection Agency, n.d.). These projects are either flaring LFG or utilizing it in other end uses, such as electricity generation or as a boiler fuel. We assume that all LFG projects above the breakeven threshold could produce RNG at a cost-viable price in 2030. We adjust final values to account for reduced output from food waste diversion due to SB 1383, which mandates a 75% reduction in organic waste disposal and is expected to reduce the total volume of methane-generating materials that enter landfills in future years.

Like dairy biogas, we also calculate the capital and operating costs for LFG utilized to generate electricity. LFG projects less than 5 MW in size are eligible for PG&E's biomethane feed-in tariff of $0.1277/kWh. Electricity sold to the grid also receives a wholesale price of $0.07/kWh. An overview of parameters and formulas for LFG electricity projects are included in Table 6 below.

Table 6. Landfill gas to electricity cost assumptions

Cost category	Capital expenses	Operation and maintenance expenses	Reference
Installed cost of gas compression/ treatment and turbine	$2,340 x [capacity (kW)]- $0.103 x [capacity]^2	$0.0144 x [output (kWh)]	U.S. Environmental Protection Agency (2016)
Installed cost of electrical interconnection equipment	$250,000	5% of capital cost	U.S. Environmental Protection Agency (2016)
Plant electric utilities		$0.07/kWh	U.S. Energy Information Administration (2022)

Food waste

Carollo Engineers conducted a study that estimated both maximum and recoverable tons of food waste suitable to be diverted from California landfills for co-digestion in 2030 (Carollo Engineers, 2019). Recoverable quantities assume that between 50% and 60% of food waste can be diverted from landfills accounting for technical and economic limitations, and that waste disposal rates decrease per capita in alignment with SB 1383 goals. We adopt the average recovery rate reported in that analysis to project the cost-viable quantity of RNG derived from food waste in 2030.

Wastewater

Like food waste, we do not have project specific information for WWTPs that would allow us to filter project data using a breakeven threshold. Instead, we assume that half of wastewater treatment plants that currently utilize biogas for energy could upgrade this gas to RNG at a competitive price in 2030. We source current biomethane consumption data from Jaffe et al. (2016).

LIFE-CYCLE CLIMATE IMPACTS

CARB's methodology for calculating the life-cycle carbon intensity (CI) of RNG differs by production pathway. Biogas derived from dairy manure and some organic waste pathways is assumed to be vented under business-as-usual conditions that are associated with high GHG emissions (California Air Resources Board, 2018a). When biogas is upgraded to RNG, CARB attributes the final fuel with an avoided emission credit, lowering its lifecycle CI.

CARB uses operational data provided by project applicants and emission factors published in a modified version of the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies model (CA-GREET) to calculate unique CI score for certified RNG pathways. Figure 3 shows the range of CI values for pathways certified under the LCFS by feedstock type in grams of carbon dioxide equivalent per megajoule of fuel (gCO_2e/MJ). The average CI across each production pathway is shown relative to the baseline CI for fossil diesel.[1] The range in certified scores across pathways is shown in the error bars.

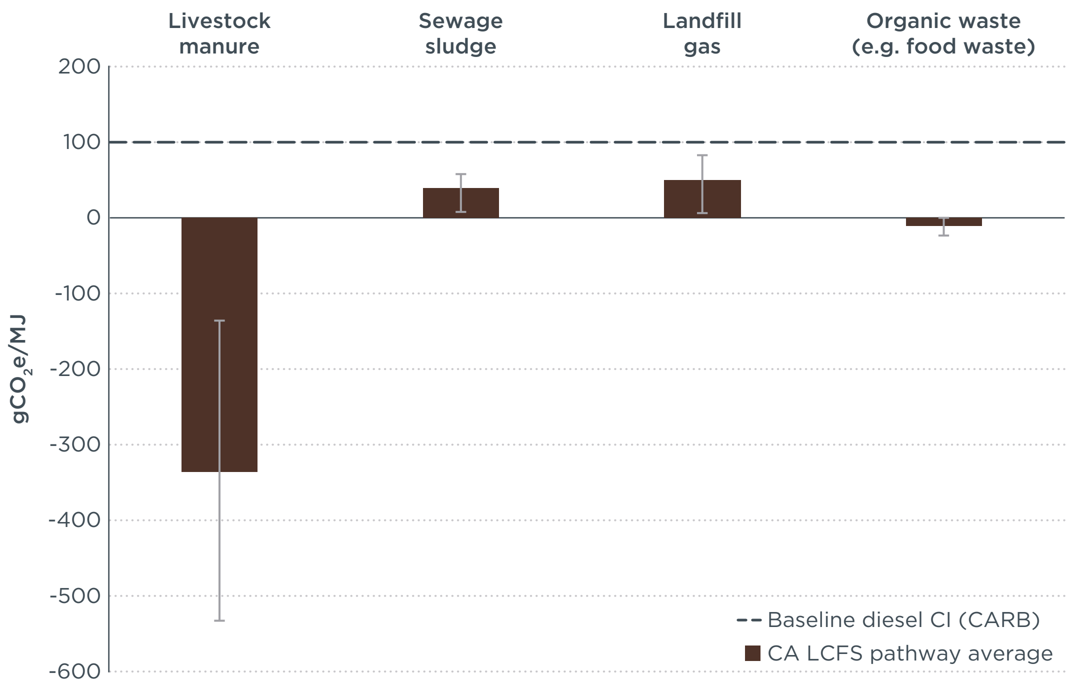

Figure 3. Average certified CI values by feedstock type compared to default scores in GREET

As a broad category, RNG generally qualifies for a low or negative CI score, with RNG derived from livestock manure having the lowest assigned CI, ranging from -533 to -151 gCO_2e/MJ. The average CIs of sewage sludge (40 gCO_2e/MJ) and landfill gas derived RNG (51 gCO_2e/MJ) are significantly higher than manure-derived biogas due to the assumption that methane is flared rather than vented in the baseline scenario. The average CI for digester projects that process organic waste is -11 gCO_2e/MJ.

We examine the effects of altering several input parameters on the final fuel CI, including distance from the upgrading facility to fueling station, makeup of the electricity grid, and frequency of fugitive methane release. The baseline parameters used in the default scenario and associated CI value are included in Table 7.

Table 7. Baseline assumptions for dairy manure RNG sensitivity analysis

Parameter	Assumption
Baseline manure management system	Lagoon venting
Electricity grid mix for biogas upgrading	Defined in CA-GREET
Days of uncontrolled venting at the digester	3 days
Fugitive methane release – biogas upgrading	2%
Baseline CI	-430.34 gCO_2e/MJ

1 Throughout this report, we report average CIs as pathway-specific CI scores averaged across LCFS lookup tables. These values are not energy-weighted, so they may differ with CI values reported by CARB or other sources.

We also compare the climate impact of upgrading biogas to RNG relative to utilizing it as electricity in a "pre" (i.e., current) and "post" (i.e., no avoided methane emissions) regulatory environment for dairy digesters. The average CI for electricity and RNG applications is drawn from CARB's LCFS pathways tables for the pre-regulatory estimates and using the Tier 1 emissions calculators for the post-regulatory estimates. Updates to avoided methane assumptions are not expected to impact the revenue streams for the remaining RNG pathways.

ESTIMATING THE VEHICLE AND FUEL-CYCLE IMPACTS OF RNG-FUELED TRUCKS

To evaluate the impact of RNG on the fuel mix for the heavy-duty vehicle (HDV) sector in California, we draw upon the analysis of O'Connell et al. (2023) and Bieker (2021) to compare the impacts of RNG deployment to other HDV vehicle technologies. This analysis compares the life-cycle GHG impacts of both the vehicle and fuel cycles for RNG-fueled class 8 tractor-trailers to alternative technologies to better understand its relative GHG savings. We compare the full life-cycle emissions for CNG-fueled trucks fueled by the California gas mix and battery electric trucks fueled by the current California electricity grid mix to a conventional, fossil diesel-powered truck.

For the vehicle cycle, we assume that the vehicle lifetime for all power trains is 18 years, based Davis et al. (2021). We include emissions attributed to the manufacturing of a Class 8 tractor-trailer, including raw material extraction and processing, vehicle manufacture and assembly, and end-of-life recycling of recoverable vehicle components, based on analyses by Scana (2021) and Ricardo (2020). For the battery electric truck, we include battery raw material extraction and processing emissions, manufacturing emissions, and one battery replacement over the course of the vehicle lifetime. We also include maintenance emissions, which are estimated on a per-km basis at 4 to 7 gCO_2e/km, equally across the different power trains (Ricardo, 2020). The key vehicle cycle assumptions are summarized in Table 8.

Table 8. Vehicle cycle assumptions for Class 8 tractor-trailer

	Power train	Value (2021)	Source
Efficiency	Diesel ICE	33.05 L/100 km	Basma et al. (2021)
	CNG ICE	28.83 kg/100 km	Mottschall et al. (2020)
	Battery electric	138.06 kWh/100 km	Basma et al. (2023)
Battery weight	Battery-electric	7,500 kg	Basma et al. (2021)
Battery capacity	Battery-electric	753 kWh	Davis et al. (2021)
Vehicle lifetime	All	18 years	Davis et al. (2021)
Lifetime VMT	All	132,681 miles	ROADMAP Model (2022)

Vehicle glider and chassis manufacturing emissions are based on Scana (2021), which estimates approximately 6.6 tonnes CO_2e per tonne for diesel trucks, with separate production emission factors used for the vehicle and battery. Based on the trend identified in Ricardo (2020), vehicle manufacturing emissions are increased by 6% for CNG trucks. Therefore, total production emissions are estimated to be 98 tonnes CO_2e for a diesel truck, and 104 tonnes CO_2e for a CNG truck. A battery electric truck has manufacturing emissions of 88 tonnes for the truck itself; however, battery manufacturing emissions of approximately 60 kgCO2e/kWh add another 54 tonnes

CO_2e to the truck's lifecycle emissions. One battery replacement over the course of the vehicle lifetime increases the total emissions to 107 tonnes CO_2e.

To calculate the well-to-wheel (WtW) lifecycle emissions of RNG for the fuel cycle of the trucks studied, we utilize emissions from RNG, fossil natural gas, grid-average electricity, and fossil diesel fuel. We assume that RNG is one component of the mix of fuel supplied to the CNG trucks (5.2%), based on in-state RNG production relative to the share of natural gas consumption. Emission factors for fossil diesel and natural gas are drawn from default values in CA-GREET 3.0. For electricity in 2021, we use the LCFS-certified value of 81.5 gCO2e/MJ (CARB, 2022). For CNG in 2021, we assume a weighted average mix of in-state CNG sources, as calculated above, with an average CI of -192.2 gCO2e/MJ. We assume that avoided methane emissions for dairy biogas are included until 2024; subsequently, we use the revised CI for dairy biogas of 41.0 gCO_2e/MJ.

We assume a gradual change of the fuel mix across 18 years of vehicle use. We maintain the same carbon intensity for the diesel truck, as it is intended to be a fossil comparator. For electricity, we project a decarbonization of the California electricity mix through 2038 based on the EIA annual energy outlook, declining from 2021 average emissions of 81.5 gCO_2e/MJ to 51.5 gCO_2e/MJ in 2038. For CNG, we assume that its composition within the fuel mix reaches its full theoretical potential of 10.8% of the California natural gas mix by 2030 and increases to 21.8% through 2038. The weighted average contribution of CNG within the gas mix has a CI of 35.3, and is predominantly produced from landfill gas, followed by livestock manure. Table 9 provides an overview of the fuel life-cycle CIs used in this analysis, illustrating the change in emissions from 2021 to 2038.

Table 9. Overview of fuel life-cycle values for 2021 and 2038 used for this analysis

	Well-to-tank emissions	Tank-to-wheel emissions	Well-to-wheel emissions	Well-to-tank emissions	Tank-to-wheel emissions	Well-to-wheel emissions
	2021			2038		
Powertrain	gCO_2e/MJ					
Fossil diesel	26.0	74.9	100.9	26.0	74.9	100.9
Fossil CNG	20.5	60.7	81.3	20.5	60.7	81.3
Biogas CNG (CA mix)	-191.5	0	-191.5	35.3	0	35.3
Electricity (CA grid mix)	81.5	0	81.5	51.5	0	51.5

RESULTS

We calculate the maximum resource potential of RNG in California and an estimate of cost-viable RNG production in 2030 under a pre- and post-regulatory scenario, as defined below. We also review the impact of altering input assumptions on RNG's final CI value, such as the inclusion of avoided methane emissions crediting. Lastly, we compare the lifecycle GHG emissions of diesel-fueled, CNG, and battery electric tractor trailers across an 18-year vehicle lifetime.

MAXIMUM RNG POTENTIAL

We estimate that RNG has a maximum resource potential of 87.4 trillion BTU per year (704 MM DGE) in California. This represents 12% of national resource potential. The majority of the potential is from landfill gas (40%), followed by dairy digesters (32%), food waste (18%), and WWTPs (10%). We find that utilizing all biomethane resources from anaerobic pathways as RNG could displace up to 10.8% of demand for natural gas in California. Within the HDV sector specifically, we estimate that the total RNG resource potential could displace up to 18.7% of demand for fuel including petroleum diesel, renewable diesel, fossil gas, and biogas consumed in transportation.

When comparing the maximum resource potential for RNG in California with its current production, taken from Argonne National Laboratory, (2022), we find that the bulk of RNG potential in-state is either unutilized or used in non-transport applications. Figure 4 compares the current volumes of RNG production in the United States and California with their maximum resource potential in trillion BTU per year. According to our maximum growth estimates, the volume of RNG produced from dairy gas and landfill gas could grow five- to seven-fold, while the volume of RNG produced from WWTPs could grow nearly thirty-fold if methane capture rates achieved 100% efficiency. In absolute terms, landfill gas pathways have the largest potential room for growth in RNG supply, primarily from existing landfill gas-to-electricity generators.

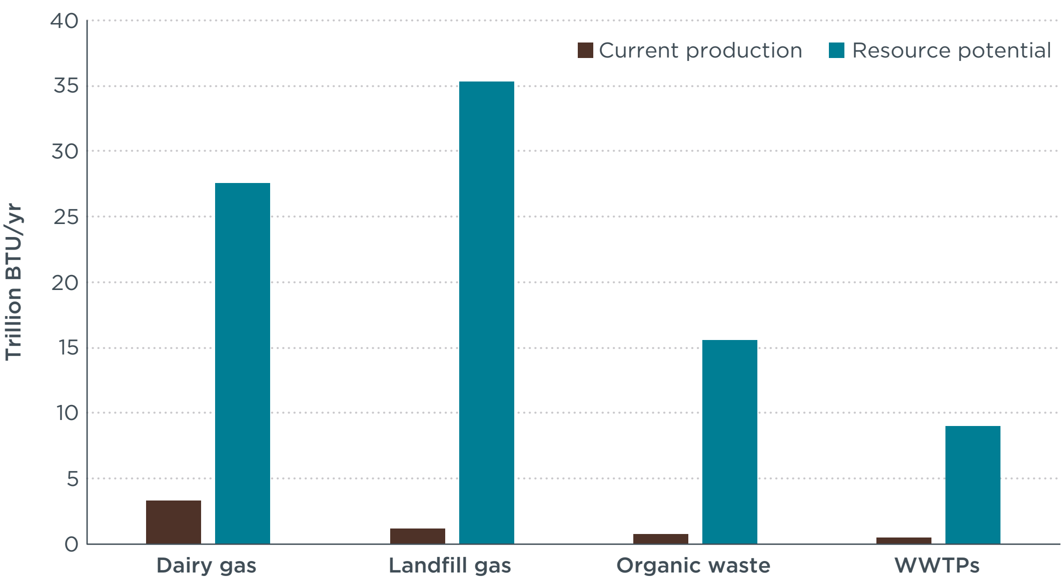

Figure 4. Current production and resource potential of RNG from select fuel pathways in California

COST ASSESSMENT

The estimates of resource potential above do not reflect the feasible and cost-viable volume of RNG that could be injected into the natural gas grid. Below we assess the RNG volumes that are cost-viable over a 10-year project crediting period under pre- and post-regulatory scenarios. We define the pre-regulatory scenario as a continuation of current LCFS crediting methodology. Under a post-regulatory scenario, we assume the level of LCFS revenue that digester facilities receive per energy equivalent unit of fuel produced decreases. This scenario assumes that avoided methane crediting is phased out upon the implementation of SB1383 in 2024.

Pre-regulation

At cost-viable prices, including currently available policy incentives, we estimate that RNG output in California could increase six-fold over the next decade, from 6.9 trillion BTUs in 2021 to 41.8 trillion BTUs (337 MM DGE) in 2030. In total, this contribution of RNG could displace 5.2% of natural gas demand in California or 9% of fuel demand across the heavy-duty sector in 2030. Landfills and food waste co-digestion projects exhibit the greatest room for growth, while dairy digester projects exhibit the lowest rate of new resource potential. Most landfill gas today is captured and flared or utilized as electricity; thus, upgrading these fuel volumes into RNG would result in a diversion of gas from its existing end uses.

Landfill-based RNG projects are highly cost-competitive because most facilities are already equipped with a biogas capture system. Therefore, their capital costs are limited to upgrading, compression, and grid interconnection costs. The breakeven project size for these systems is 0.265 million cubic feet of gas per day, far lower than the average landfill gas project flowrate in California. We find that only 3.8% of landfill gas in California, or 1.3 trillion BTUs per year, fall below the breakeven project threshold.

Support from federal and state programs has facilitated growth in dairy digester projects to date; however, the number of remaining farms suitable for biogas upgrading in California has shrunk. We determine the breakeven farm size for facilities with an existing digester to be approximately 2,300 dairy cattle heads, assuming an extension of current policy support. We find that dairy cattle facilities that already have an anaerobic digester but are not yet upgrading captured biogas could contribute an additional 1.88 trillion BTU (15 million DGE) of RNG to the heavy-duty fuel sector in 2030, a 47% increase from current production levels. For projects that are not already equipped with anaerobic digesters, such as small organic farms and solid storage operations, we find that all are cost-prohibitive in 2030. This is due to the high capital costs of building new digester equipment, additional labor costs associated with trucking manure, and low LCFS credit value for non-AD production pathways.

We do not have project-specific information on existing food waste or WWTP projects, so our cost-competitive resource estimates are adopted from our literature review. We find that RNG production rates could increase by 1.9 and 8.6 trillion BTUs in 2030 from 2021 levels for WWTP and food waste pathways, respectively.

We present the maximum resource potential in trillion BTUs for each feedstock pathway alongside current RNG production in California in Figure 5. The figure also displays our calculations for cost-viable growth of RNG in 2030.

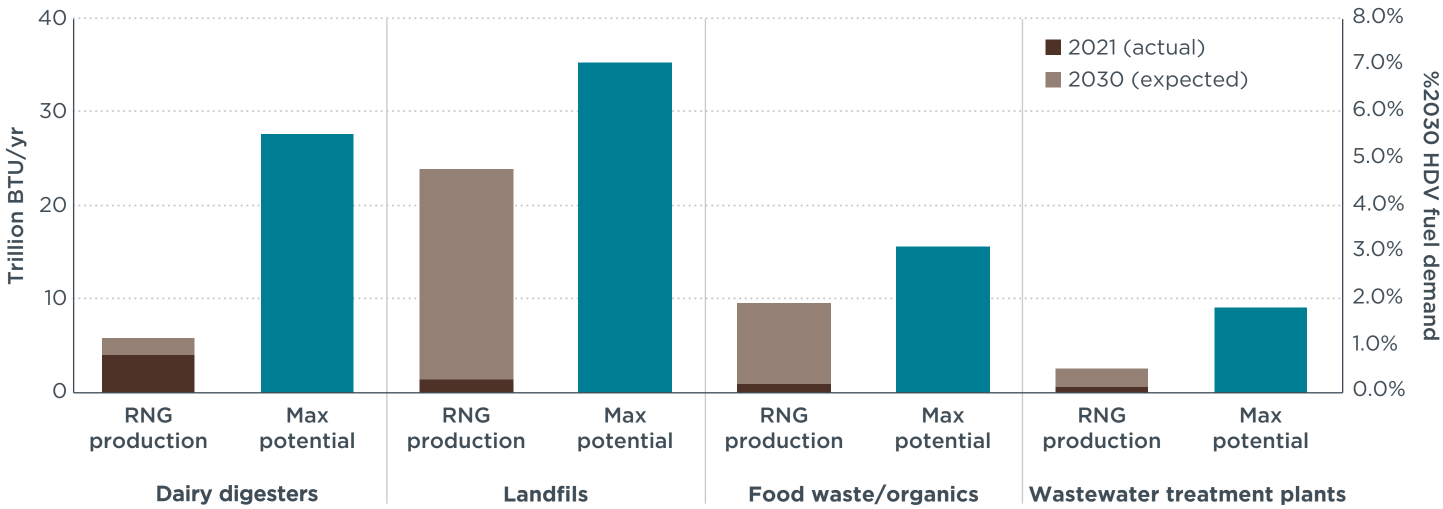

Figure 5. RNG production and maximum potential relative to heavy-duty vehicle fuel demand in California

Post-regulation

We also estimate the break-even costs for dairy digester projects after binding methane regulations go into effect in 2024. It is unclear what the impact this will have on the CI calculation for biogas pathways in the LCFS; however, we assume that an updated baseline sets avoided methane emissions to zero within the LCFS, consistent with an analysis published by Lee and Sumner (2018a). We find that this increases the average CI value for dairy digesters significantly to 36.4 gCO_2e/MJ.

We find that dairy digester projects would require approximately 6,500 dairy cows to achieve breakeven costs in 2030, significantly higher than our pre-regulatory estimate. Under this threshold, we find that existing digesters could generate 1.18 trillion BTU (9.5 MM DGE) of additional RNG potential, a 30% increase from current levels.

We also calculate the breakeven costs for dairy farms that are not yet equipped with an anaerobic digester and would require pooling resources together at a centralized location to achieve economies of scale. These farms make up less than 10% of the dairy cattle population in California (U.S. Environmental Protection Agency, 2018), but have been explored as a method to meet the goals of the SLCP strategy (CARB, 2017b). In addition to the costs outlined above, these projects would incur additional costs from trucking manure to a central location. We estimate a minimum threshold of more than 30,000 dairy cattle head for projects that require the additional capital to build an anaerobic digester. This estimate is larger than the size of the Kern County dairy cluster, the largest dairy digester project operating in California today (Black, 2019). Due to a lack of remaining farm clusters with comparable resource potential, we assume that pooling resources for manure handling is not a feasible strategy for future farms. For farms already equipped with a digester, we find that a reduction in LCFS credit value under a post-regulatory scenario would only reduce in-state cost-competitive RNG production by 1.4%.

With a revised CI in place that removes avoided methane crediting from Tier 1 emissions calculations, we estimate RNG projects could achieve 48% of their maximum resource potential in California at a competitive cost in 2030. We find that if avoided methane emissions are no longer credited under the LCFS, the effect on total in-state, cost-competitive RNG production is minimal. This is because the majority of the largest, most cost-effective farms are already generating RNG under the LCFS, whereas smaller-scale dairy farms would be unaffected by a CI revision. Small farms' use of solid manure management systems and their small capacity make them unlikely candidates for RNG under current policy. In addition, because their baseline conditions already have substantially lower methane emissions than concentrated large dairies with liquid manure treatment, their CI would likely remain similar if LCA methodology was reassessed by CARB. However, the impact of a revised CI would be significant for the larger number of digester projects located outside California. Although these producers are not subject to California's methane regulations, we note that applying a revised CI only to in-state producers could place them at a competitive disadvantage.

There is significant room for growth for landfill gas and organic waste pathways in 2030 that are not impacted by the implementation of SB 1383. Landfill gas has the highest resource potential of all pathways, but most of that potential would come from diverting that gas from existing uses in the power sector. Upgrading landfill gas to RNG is a less efficient use than combusting it for bioelectricity for the transport sector. The energy content of landfill gas can be used more efficiently in BEVs than NGVs and requires fewer processing steps that could result in methane leakage, as described in the following section. Diverting electricity to gaseous applications would be lucrative for producers stacking LCFS and federal RIN credits but would offer no additional benefit toward meeting LCFS CI reduction targets.

Sensitivity of lifecycle GHG emissions to underlying methodology

The GHG impacts of RNG vary by input parameters and, as of 2022, range between -533 gCO_2e/MJ and 90 gCO_2e/MJ across all certified LCFS pathways. We perform a sensitivity analysis to review the effects of altering different input parameters on the estimated CI of the dairy biogas pathway. This includes assumptions of whether methane is vented or captured in the baseline scenario, and whether methane is vented during the processing stage once it enters the digester. Figure 6 compares the effects of altering the baseline manure management assumptions, the makeup of the electricity grid mix, the frequency of venting at the biogas digester, and the rate of methane leakage during RNG upgrading. Values are calculated using CARB's Tier 1 emission calculator for dairy and swine manure (CARB, 2019).

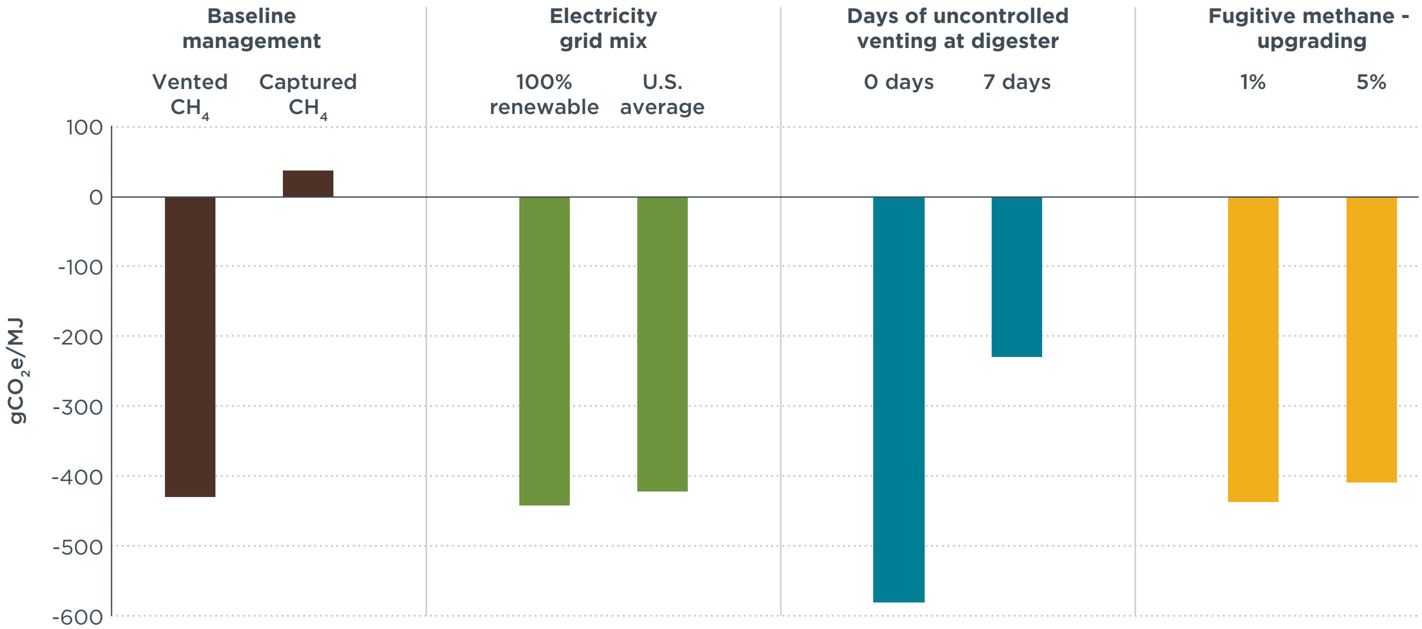

Figure 6. Sensitivity analysis of input parameters for dairy manure derived RNG under the LCFS certification process

Manure management practices have the largest impact on CI estimates, ranging from -430.3 gCO_2e/MJ when methane is assumed to be vented 100% of the time to 36.4 gCO_2e/MJ when methane is assumed to be captured 100% of the time. In both cases, the digester is assumed to operate under three days of uncontrolled venting, consistent with the baseline assumptions listed in Table 7. The frequency of uncontrolled venting also has a large impact on CI estimates, ranging between -580.8 gCO_2e/MJ if no methane is vented to -229.7 gCO_2e/MJ if methane is vented 7 days out of each month, or roughly 25% of the time. The resource makeup of the electricity grid and rate of fugitive methane release during upgrading have a modest effect on the final CI. The distance that biomethane must travel from the feedstock source to the RNG fueling station only has a minor effect on final CI, which we do not display in Figure 6.

The average CI values for electricity and RNG derived from dairy farm digesters in a pre- and post-regulatory scenario are shown in Figure 7. The CI estimates do not change for small dairy farm projects that process manure in solid storage or pasture applications or for landfill gas projects that assume methane capture under business-as-usual conditions (i.e., in the absence of biofuels policy).

For dairy farm digesters projects, electricity applications have a lower CI than pipeline injected gas in both cases. Although electrical energy conversion for biogas generators is only 33% efficient, it has fewer methane losses along the fuel supply chain than pipeline-injected gas. It also requires less recycled RNG or fossil natural gas for biogas upgrading. Lifecycle emissions increase significantly in the post-regulatory scenario when methane is assumed to be captured rather than vented as under business-as-usual conditions.

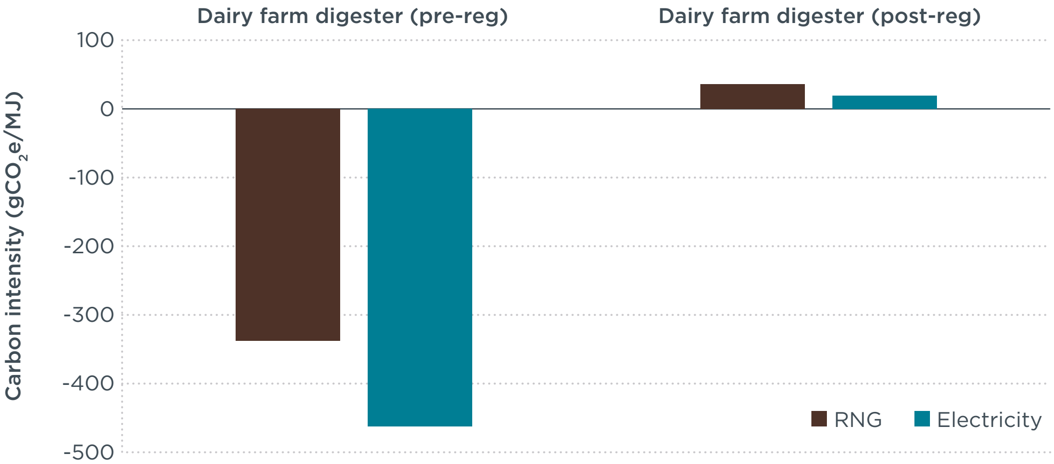

Figure 7. Average CI comparison of electricity versus RNG biomethane applications

LIFE-CYCLE IMPACTS OF RNG TRUCKS

Figure 8 illustrates the differences in life-cycle emissions attributable to three different power trains in class 8 tractor-trailers, across an 18-year lifetime of use. As shown, the emissions are dominated by the use phase for fuel consumption and fuel production. On a life-cycle basis, we find that the California-average CNG mix offers a 11% life-cycle GHG emissions reduction compared to a conventional, fossil-diesel powered truck, largely attributable to the slight decrease in CI of the natural gas mix compared to conventional fossil diesel fuel. This figure reflects the case wherein a CNG truck fuels at a standard fueling station where there is not a dedicated supply of RNG, reflecting the statewide mix of fuels over time. The battery electric truck, also fueling with a state-average mix of electricity sources, generates approximately 57% GHG savings compared to the conventional diesel truck.

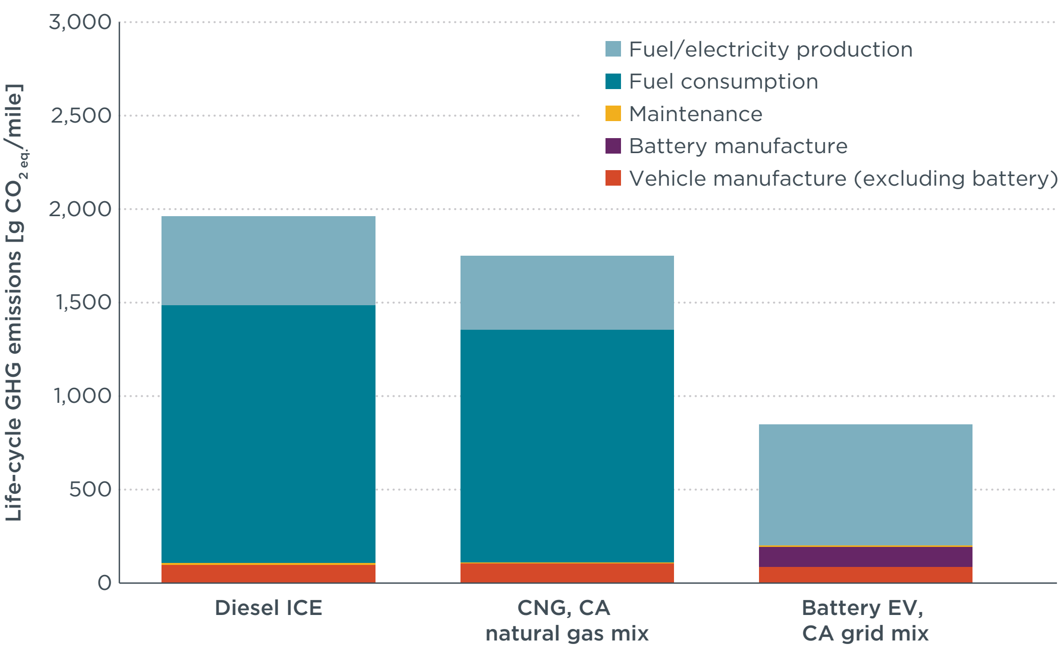

Figure 8. Comparison of vehicle lifetime emissions for a diesel-fueled truck, a CNG truck fueled by the California gas mix, and a battery electric truck fueled by the California electricity grid mix.

Comparing powertrains, we find that upstream vehicle manufacturing emissions are comparable between CNG and diesel trucks but are approximately half that of battery electric trucks once battery manufacturing costs and battery replacement are included. However, the contribution of upstream manufacturing emissions to each vehicle's total emissions is relatively low, as use phase emissions are substantially higher, even for the battery electric case. We find that the impact of biomethane in the CNG truck case is muted because biomethane comprises a very small share of California natural gas, and its contribution does little when averaged in with fossil natural gas. Furthermore, the negative crediting for biomethane in the pre-2024 period has a low impact on the truck's lifetime life-cycle emissions due to the bulk of the vehicle's assumed lifetime extending beyond 2024. We find that the change in crediting after 2024 outweighs the increase in biomethane in the gas grid mix. In contrast to biomethane, the electricity grid emissions decline every year of the analysis and thus results in lower lifetime GHG emissions for the BEV truck.

Applying the methodology of the vehicle cycle LCA to the proposed, post-regulation CI values for biomethane, we find that in dedicated uses, biomethane can generate meaningful GHG reductions compared to conventional fossil fuels. Figure 8 compares the life-cycle impacts of fueling a Class 8 CNG tractor-trailer with dairy manure-derived biomethane, a battery electric truck fueled by dairy manure-derived biogas electricity, and a conventional, diesel-fueled tractor trailer. Even when using the revised CI value, we find that biomethane from dairy manure still generates over 50% GHG savings relative to conventional natural gas, and 55% on a vehicle lifetime basis; therefore, RNG may be useful for dedicated fleets in areas where there is a supply of RNG or injection into the common grid is not possible.

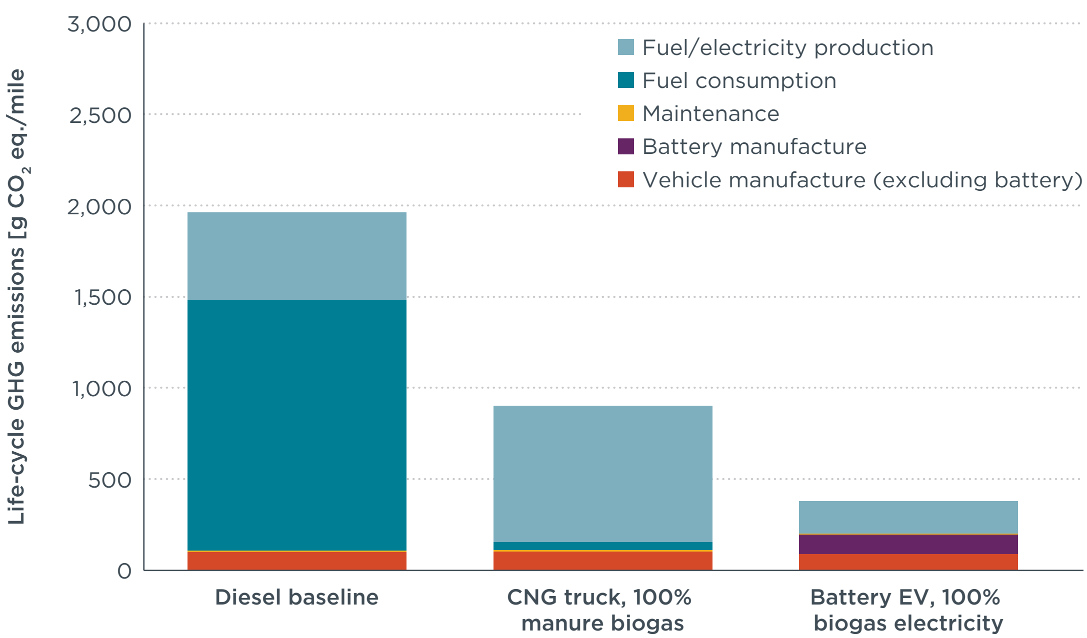

Figure 9. Comparison of vehicle lifetime emissions for a diesel-fueled ICE truck, a CNG truck fueled by 100% dairy manure biomethane, and a battery electric truck fueled by 100% dairy manure biogas-derived electricity.

Combining the LCA analysis of the biomethane supply chain with the vehicle cycle LCA suggests that, although biomethane can offer GHG reductions compared to conventional natural gas on a per unit basis, its overall impact is limited by its small share of the natural gas mix in California. Though LCFS crediting implies that biomethane plays an outsize role in decarbonizing the California transport fuel mix, this belies the relatively small quantities of biomethane produced and consumed in state within the transport sector. The relative impact of biomethane could be increased if the corresponding share of fossil natural gas declines; however, a phaseout of natural gas use will limit investment opportunities to facilitate biomethane injection at new pipeline locations.

In conjunction with the efficiency of battery-electric power trains, we find that using the same biogas to produce electricity for the transport sector could displace more petroleum and reduce emissions further than upgrading it to RNG, generating approximately 81% GHG savings relative to a fossil diesel baseline across the vehicle lifetime, as shown in Figure 8. This suggests that, rather than constructing costly pipeline interconnections, it may be possible to utilize biogas in the transport sector to fuel the emerging battery electric fleet.

POLICY RECOMMENDATIONS

The implementation of SB1383 in 2024 presents California state agencies with the opportunity to align the goals of concurrent statewide climate policies. Stakeholders have identified that current LCFS program design may over credit the production of RNG by rewarding producers for undertaking environmental management practices that were occurring in the absence of biofuel demand. In some cases, inflated LCFS credit values could incentivize the production of additional biomethane via resource consolidation and high methane-generating management practices.

Approximately 70% of RNG credited under the LCFS is produced outside of California without a traceability or deliverability requirement. Thus, the majority of volumes claimed under the program may never be delivered to California customers, clouding the program's real-world climate impact. The growth of in-state RNG production could theoretically scale up to meet 19% of HDV demand in California, although this share is limited in practice due to cost constraints and investment uncertainty. Two major policy changes would help to match the decarbonization potential of RNG projects with the level of financial support it receives from grants and market-based incentive programs.

- **Update the CI value for dairy biogas projects by removing avoided methane emissions crediting.** SB1383 requires a 40% reduction in statewide methane emissions by 2030. Although methods to meet this goal are not prescriptive, capturing methane at facilities with uncapped or vented operations is one of the most cost-effective methods for reducing methane emissions. Rewarding RNG projects with avoided methane credits could misrepresent the lifecycle climate impact of biogas production if those methane emissions are regulated by other policies. We therefore recommend that CARB implement a uniform methane crediting phaseout so that in-state RNG producers do not bear a competitive disadvantage compared to out-of-state projects.
- **Restrict the use of book-and-claim accounting for RNG crediting to in-state projects.** Approximately 70% of RNG credited under the LCFS in 2021 was produced outside of California. This fuel may be delivered to customers located outside California and consumed in non-transport applications. To better align LCFS crediting with a fuel's ability to displace in-state petroleum consumption, we recommend restricting the practice of book-and-claim accounting to within California's boundaries. This practice is consistent with CARB's consideration for a phase-down of avoided methane crediting with a 10-year credit lock-in and guidelines for low-CI electricity accounting under the LCFS program (California Air Resources Board, 2022).

CONCLUSION

The growth of California's RNG market has resulted in a growing share LCFS compliance that is decoupled from its ability to displace in-state petroleum consumption. Due to the use of book-and-claim accounting, there is no guarantee that credited RNG volumes are being consumed in the transport sector or by California customers. Binding methane regulations implemented under SB1383 may update the baseline assumptions for dairy manure management and thus prompt a revision of the CI for dairy biogas to exclude avoided methane emissions. A revised CI for manure-based biofuel pathways that reflects a scenario where methane is captured at the source could better reflect the GHG emissions of RNG and match its contribution toward meeting the goals of the LCFS.

A revised CI would greatly reduce the LCFS credit value for mid-to-large size dairy manure producers, particularly for those farms outside California who have not yet entered the program. For an average dairy digester project credited in California, this would change the LCFS credit value from approximately $5.61/DGE to $0.72/DGE assuming an LCFS credit price of $100/mt. In contrast, existing projects certified under the LCFS will retain their certified credit values for 10 years. Thus, revising the CI would largely limit the growth of biomethane crediting in the LCFS to new and out-of-state producers, while providing a longer off-ramp to existing producers. We find that a revised CI value would have little to no effect on small-scale operations, such as organic farms that treat methane in pasture or solid storage applications.

From a resource perspective, biomethane is in limited supply and can only make a small contribution toward displacing fossil natural gas and heavy-duty vehicle demand in California. Factoring in cost-constraints, we find that in-state supply can displace approximately 8.9% of heavy-duty vehicle fuel demand in 2030. However, RNG can still have a role to play in transport decarbonization via dedicated trucking fleets or electrification. We find that dedicated RNG fleets reduce GHG emissions over the entire vehicle lifecycle by 55% while battery EVs powered by biogas electricity reduce GHG emissions by 81%. Combusting biomethane into electricity, whether to serve the power sector or delivered to BEV customers, is often cheaper to produce than RNG and has additional GHG savings due to fewer treatment steps required and the avoidance of fugitive methane release during biogas upgrading.[2]

2 For more information, see case studies published with this study.

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