ALJ/KJB/sgu 6/3/2021

FILED
06/03/21
03:45 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions.	Rulemaking 13-02-008

ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING PARTIES TO FILE COMMENTS ON PHASE 4A STAFF PROPOSAL AND RELATED QUESTIONS

To help implement SB 1440 (Hueso, 2018), Energy Division staff has prepared a Staff Proposal as part of Phase 4 of this proceeding, a copy of which is attached to this ruling. The Staff Proposal provides background information, addresses challenges, and makes specific recommendations relating to the establishment of a biomethane procurement program for California gas investor-owned utilities.

In this ruling, I am directing parties to file comments on the Staff Proposal, specifically including responses to the four following questions:

1. Do you agree with Energy Division's proposed method of determining cost-effectiveness? Why or why not? What, if anything, would you change?
2. Do you agree with Energy Division's proposed procurement targets? Why or why not? What, if anything, would you change?
3. Energy Division proposes 10 recommendations in addition to their proposed cost-effectiveness approach and procurement targets. Please address each of the 10 additional recommendations individually, stating

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whether you agree with them or not and specifying what, if anything, you would change.

4. Is there anything else that was not addressed in the Staff Proposal that you think should be considered as part of a biomethane procurement program? Please explain.

IT IS RULED THAT

1. Parties shall file comments on the Staff Proposal attached to this ruling.
2. Comments shall specifically address Questions 1 through 4, above.
3. Comments shall be filed no later than June 30, 2021.

Dated June 3, 2021, at San Francisco, California.

/s/ KARL J. BEMESDERFER

Karl J. Bemesderfer
Administrative Law Judge

Attachment 1

California Public Utilities Commission

R.13-02-008 Phase 4A Staff Proposal (DRAFT)

CPUC ENERGY DIVISION STAFF

June 1, 2021

Table of Contents

Acronymns & Abbreviations

AB	Assembly Bill
AL	Advice Letter
BAC	Bioenergy Association of California
Bcf	Billion Cubic Feet
Biogas	As defined in Health and Safety Code Section 25421.
Biomass	Non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms, including: products, by-products, residues and waste from agriculture, forestry, and related industries; the non-fossilized and biodegradable organic fractions of industrial and municipal wastes; and gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.
Biomethane	As defined in Public Utilities Code Section 650. Upgraded biogas or upgraded Bio-SNG that meets pipeline quality standards
Bio-CNG	Compressed natural gas that is produced from biomethane rather than fossil natural gas. Bio-CNG has equivalent performance characteristics when compared to fossil CNG.
Bio-SNG	Bio-synthetic natural gas. A mixture composed primarily of methane, carbon dioxide, and water produced by chemical conversion (catalytic methanation) of purified and conditioned renewable syngas. Also contains low concentrations of carbon monoxide, hydrogen, and other minor constituents
BPP	Biomethane Procurement Plan
CalEPA	California Environmental Protection Agency
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCS	Carbon Capture and Storage
CCST	California Council on Science and Technology
CDFA	California Department of Food and Agriculture
CEC	California Energy Commission
CH_4	Methane

CHBC	California Hydrogen Business Council
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPUC	California Public Utilities Commission
CRNG	Coalition for Renewable Natural Gas
CTA	Core Transport Agent
DDRDP	Dairy Digester Research and Development Program
DER	Distributed Energy Resource
ED	Energy Division
EER	Energy Economy Ratio
EPA	United States Environmental Protection Agency
GHG	Greenhouse Gas
GRC	General Rate Case
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
IPCC	International Panel on Climate Change
IWG	Federal Interagency Working Group
LCFS	Low Carbon Fuel Standard
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units.
MMcf	Million Cubic Feet
$MMTCO_2e$	Metric Tons of Carbon Dioxide Equivalent
MSCF	Thousand standard cubic feet
OEHHA	Office of Environmental Health Hazard Assessment
PFAS	Per- and Polyfluoroalkyl Substances
PG&E	Pacific Gas & Electric Company
PU	Public Utilities
RFS	Renewable Fuel Standard

RG	Renewable Gas
RIN	Renewable identification number
RNG	Renewable Natural Gas
SB	Senate Bill
SBPM	Standard Biomethane Procurement Methodology
SDG&E	San Diego Gas and Electric Company
SLCP	Short-Lived Climate Pollutant
SNG	Synthetic Natural Gas
SoCalGas	Southern California Gas Company
SRGI	Standard Renewable Gas Interconnection
SWG	Southwest Gas Corporation
SWRCB	State Water Resources Control Board
Syngas	Synthesis gas. A mixture primarily of carbon monoxide and hydrogen that can be produced from either renewable or non-renewable source materials by non-combustion thermal conversion
VRNGT	Voluntary Renewable Natural Gas Tariff

Tables & Figures

1 Executive Summary

On November 21, 2019, the California Public Utilities Commission (CPUC) initiated Phase 4 of Rulemaking (R.) 13-02-008 to implement Senate Bill (SB) 1440 (Hueso, 2018),[1] which requires the CPUC to consider adopting biomethane procurement targets or goals for each investor-owned utility (IOU) providing gas service in California. The Phase 4 scoping memo[2] outlined three specific action items necessary to implement SB 1440: (1) consultation with the California Air Resources Board (CARB) resulting in a staff report, (2) a determination as to whether biomethane procurement targets or goals can be adopted in a cost-effective manner while complying with all applicable state and federal laws, and (3) consideration of seven specific issues necessary to ensure compliance with California Public Utilities (PU) Code Section 651(b).[3] A subsequent amendment to the Phase 4 scoping memo made on June 5, 2020[4] added seven additional issues for consideration, bringing the revised total to 14.

Phase 4 record development began in late 2019 and continued into 2020. On December 6, 2019, the CPUC's Energy Division (ED) hosted a workshop on SB 1440 implementation that featured presentations from the Bioenergy Association of California (BAC), Coalition for Renewable Natural Gas (CRNG), California Hydrogen Business Council (CHBC), Pacific Gas & Electric Company (PG&E), Southern California Gas Company (SoCalGas), and Southwest Gas Corporation (SWG).[5] On January 10, 2020, 20 separate comments were filed by parties representing gas corporations, biomethane producers, union workers, consumers, environmentalists, environmental justice advocates, and others.[6] Reply comments were filed on January 27, 2020 by CHBC and CRNG. Subsequent developments in R.13-02-008 focused primarily

[1] *See*: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB1440.
[2] *See*: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K307/320307147.PDF.
[3] The third action item is contingent on a finding that biomethane procurement targets or goals can be adopted in a cost-effective manner while complying with all applicable state and federal laws.
[4] *See*: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M339/K310/339310939.PDF.
[5] Workshop details can be found at https://www.cpuc.ca.gov/Renewable_natural_gas/.
[6] Parties include: (1) Agricultural Energy Consumers Association (AECA), (2) BAC, (3) California Biomass Energy Alliance (CBEA), (4) California Municipal Utilities Association (CMUA), (5) Central California Asthma Collaborative and Leadership Counsel for Justice and Accountability (EJ Advocates), (6) CHBC, (7) Coalition of California Utility Employees (CCUE), (8) CRNG, (9) Dairy Cares, (10) Environmental Defense Fund (EDF), (11) First Solar, Inc., (12) Gas Technology Institute (GTI), (13) Midwest Renewable Energy Tracking System (MRETS), (14) PG&E, (15) San Diego Gas & Electric Company (SDG&E) and SoCalGas (Sempra), (16) San Joaquin Renewables LLC (SJR), (17) SeaHold LLC, (18) Sierra Club, (19) SWG, and (20) The Utility Reform Network (TURN).

on Phase 3 of the proceeding, which concluded on December 17, 2020 with the adoption of Decision (D.) 20-12-031.[7]

This Staff Proposal was developed by ED staff (Staff) in consultation with several other state agencies[8] and is intended to satisfy the first of the three action items relating to SB 1440 implementation outlined in the Phase 4 scoping memo. First, Staff provide background information regarding what biomethane is, the regulatory context in which gas service is provided, how biomethane policy has developed in California in recent years, what biomethane incentives currently exist, and how CARB's Cap-and-Trade program is relevant to biomethane procurement considerations. Second, Staff address various challenges associated with complying with the requirements of SB 1440, including how to center environmental justice in the procurement discussion, how to determine cost-effectiveness, how the high price of biomethane could impact procurement decisions, and how to prioritize across multiple sources of biomethane. Finally, Staff offer specific recommendations relating to cost-effectiveness, goals, targets, and other considerations.

Staff recommend approval of a mandatory biomethane procurement program for California's four large gas IOUs to procure on behalf of their core customers. Those gas IOUs would be required to procure biomethane derived from organic waste at levels sufficient to meet California's statutory obligation to divert 75 percent of organic waste away from California landfills by the end of 2025. By 2030, the gas IOUs would be required to procure biomethane at levels necessary to satisfy CARB's landfill methane reduction levels outlined in their 2017 Scoping Plan. All biomethane procurement must be cost-effective according to a methodology to be developed jointly by the gas IOUs and approved by the CPUC, and all contracts submitted subsequently will be approved by advice letter at tiers determined by the cost of each contract. Each gas IOU would also be required to submit a plan for CPUC approval outlining their procurement strategy through 2030 and anticipated bill and rate impacts associated with that procurement. Numerous conditions would be placed on biomethane producers in order to be eligible for procurement of their gas by

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[7] *See*: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M356/K244/356244030.PDF.

[8] While CARB is the only state agency that the CPUC is statutorily obligated to consult with per PU Code Section 651(a), it is one of many state agencies consulted in the development of this Staff Proposal. Consultation does not imply endorsement. This Staff Proposal is ultimately reflective solely of the perspective of the CPUC staff that composed it.

an IOU, and procurement targets would be revisited in 2025. An overview of Staff's recommendations is provided below.[9]

1.1 Cost-effectiveness

Staff recommend adopting a cost-effectiveness framework modelled on a recently approved biomethane procurement program for Oregon's gas utility, NW Natural. California's four large gas IOUs should be required to jointly file and receive approval of a standardized procurement methodology that will determine cost-effectiveness and guide procurement decisions by taking into consideration the perspectives of the gas IOUs, biomethane producers, and society at large. Every biomethane procurement contract deemed cost-effective under the approved methodology should be subject to one of three different tiers[10] of CPUC approval based on procurement price. A biomethane contract for up to $17.70 per million British thermal units (MMBtu)—a value derived from a study conducted by California's State Water Resources Control Board (SWRCB)—should require Tier 1 Advice Letter (AL) approval. A biomethane contract priced between $17.70/MMBtu and $26/MMBtu—a value reflecting the social cost of methane—should require Tier 2 AL approval. A biomethane contract priced above $26/MMBtu should require Tier 3 AL approval.

1.2 Targets

Staff recommend adopting short- and medium-term biomethane procurement targets for the gas IOUs to meet by 2025 and 2030, respectively.[11] Short-term targets should be aligned with California's landfill diversion goals and medium-term targets should be aligned with California's short-lived climate pollutant (SLCP) reduction goals, both of which were established by SB 1383 (Lara, 2016). The short-term 2025 target should require the gas IOUs to prioritize biomethane procurement from standalone anaerobic digesters and wastewater treatment facilities that co-digest wastewater and diverted organic waste at levels

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[9] While hydrogen-related considerations were an additional focus of the Phase 4 scoping memo, this Staff Proposal solely addresses SB 1440 implementation. Hydrogen-related considerations will be a focus of R.13-02-008 after SB 1440 implementation is complete.

[10] A Tier 1 or Tier 2 AL is subject to disposition under General Rule 7.6.1; a Tier 3 AL is subject to disposition under General Rule 7.6.2. *See* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M023/K381/23381302.PDF.

[11] Each IOU has a gas procurement department that purchases gas for core customers. Under the Federal Energy Regulatory Commission (FERC)'s Standards of Conduct rules, there is a firewall between the gas procurement department and the IOU's System Operator. The gas procurement divisions are treated like non-utility customers and only have access to public information about the IOU's gas system.

sufficient to divert eight million tons of organic waste.[12] This volume reflects the California Department of Resources Recycling and Recovery's (CalRecycle's) estimated additional capacity needs for 2025.[13] In 2025, the CPUC should revisit the targets and adjust according to feedstock availability, natural gas demand, and optimal use for biomethane. The preliminary medium-term 2030 target for the gas IOUs should support CARB's 4 million metric tons of carbon dioxide (CO_2) equivalent ($MMTCO_2e$) landfill emission reduction goal, which translates to total annual procurement of at least 75.5 million MMBtu (72.8 Bcf) of biomethane by 2030. This procurement amount is equivalent to approximately 12.3 percent of total annual statewide gas IOU core customer consumption in 2020.[14] The medium-term target excludes dairy biomethane, except for the portion procured for Low Carbon Fuel Standard (LCFS) core procurement.

1.3 Other Considerations

Staff recommend adopting five pairs of additional biomethane procurement program requirements focused on: (1) ensuring safety, (2) minimizing costs to ratepayers, (3) preventing increases in localized particulate emissions, (4) maximizing GHG emissions reductions, and (5) facilitating the use of pyrolysis in biomethane production operations. Recommended safety requirements include adopting an interim permissible level of carbon monoxide (CO) in biomethane until the Office of Environmental Health Hazard Assessment (OEHHA) and CARB have had an opportunity to assess the constituents of concern in gas derived from the non-combustion thermal conversion of organic materials (*e.g.*, pyrolysis),[15] as well a prohibition on biomethane procurement from facilities that do not reduce hydrogen sulfide (H_2S) in biogas to safe levels before that biogas enters a gathering line. Recommended ratepayer protection requirements

[12] New technologies can reduce cost, increase ease of pre-processing waste, and increase biomethane production. California Energy Commission's (CEC) 2020 study reviews various technologies and processes for optimal biomethane generation. CEC "Lowering Costs of Food Waste Codigestion for Renewable Biogas Production" https://ww2.energy.ca.gov/2020publications/CEC-500-2020-069/CEC-500-2020-069.pdf.

[13] In order to meet the eight-million-ton organic waste diversion target, gas IOUs shall report diverted organic waste to track success metrics, which they can obtain from wastewater treatment plants charging tipping fees per ton of diverted organic waste. Biomethane production from organic waste can vary greatly depending on infrastructure and technology. For example, the Victor Valley wastewater treatment plant tripled renewable natural gas production after it was retrofitted with Anaergia's Omnivore technology that converts black bin waste to slurry for high solids anaerobic digestion. This retrofit can triple capacity and increase redundancy of the existing digester infrastructure. *See* Section 3.4.

[14] The 12.3 percent estimate is based on core customer 2020 demand, published in the 2020 California Gas Report located in two locations: https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf and https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr20.pdf.

[15] OEHHA and CARB submitted a joint report to the CPUC in 2013 on the constituents of concern in gas produced from the anaerobic digestion of organic materials. That study did not examine the constituents of concern in gas produced from the non-combustion thermal conversion of organic materials.

include a mandate that the gas IOUs each submit a procurement plan for the CPUC to approve that estimates how much biomethane each gas IOU will procure, how much their customers' bills are anticipated to increase as a result of that procurement, and any incremental capital infrastructure and/or operations and maintenance costs associated with those procurement levels between now and 2030, as well as a requirement for inclusion of a contingency clause in biomethane procurement contracts allowing prices to be renegotiated if a production facility's tipping fees[16] are increased. Recommended particulate emissions-related requirements include a requirement to prioritize biomethane procurement from facilities that use trucks that run on cleaner alternatives to diesel, as well as a requirement to prioritize procurement from biomethane producers that agree to cap on-site electric generation from combustion technologies. Recommended GHG emissions reduction maximization requirements include a prioritization of biomethane procurement from facilities that commit to carbon capture and storage (CCS), as well as changes to rules governing Core Transport Agents (CTAs)[17] so that those entities must meet or exceed the biomethane procurement levels of the gas IOUs that they are competing with. Recommended pyrolysis-related provisions include prioritizing procurement from facilities that turn their waste byproduct into soil amendment,[18] as well as the development of pyrolysis pilot projects in PG&E and SoCalGas service territories that can complement California's forest management efforts.

[16] A "tipping fee" is a fee paid by anyone who disposes of materials at a waste processing facility. *See* Section 3.4 and 4.3.
[17] CTAs are non-utility gas suppliers who purchase gas on behalf of residential and small commercial end-use customers. *See*: https://www.cpuc.ca.gov/general.aspx?id=4812.
[18] CDFA's Dairy Digester Research and Development Program projects utilize the digestate as fertilizer to the dairy crops.

2 Background

Biomethane—also called renewable natural gas (RNG)—is combustible gas produced from the anaerobic decomposition of organic materials (*i.e.,* biogas)[19] that is captured and then purified[20] to a quality[21] suitable for injection into an IOU-operated gas pipeline.[22] Major sources of biomethane include non-hazardous landfills, wastewater treatment facilities, organic waste, and animal manure. Assembly Bill (AB) 3163 (Salas, 2020)[23] specifies that, for the purpose of SB 1440 implementation, biomethane sources also include biogas derived from multiple types of organic materials processed at the same facility (*i.e.,* co-digestion) and bio-synthetic natural gas (Bio-SNG)[24] produced from the non-combustion thermal conversion of organic materials.

Biomethane can decrease methane emissions from the waste sector and be used as a direct replacement for fossil natural gas to help California reduce its GHG emissions.[25] Like pipeline quality fossil natural gas, which is extracted from beneath the earth's surface, biomethane is a mix of numerous different compounds, consisting primarily of methane (CH_4), which is combusted to operate common building appliances, power industrial operations, generate electricity, and fuel certain vehicles. Unlike fossil natural gas, however, biomethane can be produced sustainably and consistently after investing in the infrastructure necessary to capture and purify it, as it is derived from sources that are constantly being replenished as a result of regular human and animal activity. Furthermore, while fossil natural gas use results in net increased GHG emissions due to the introduction of CO_2 into the atmosphere that would have otherwise remained sequestered underground, CO_2 emissions from certain biomethane sources/production methods can be considered either carbon neutral or carbon negative after combustion. Along with CO_2 emissions from the

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[19] "Biogas" is defined by California Health and Safety Code Section 25420(a). *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=25420.&lawCode=HSC.
[20] Biogas purification is more commonly referred to as either "upgrading" or "conditioning" in industry parlance.
[21] Biomethane quality standards are determined collaboratively by a multitude of California state agencies through a process directed in California Health and Safety Code Section 25421. *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=25421.&lawCode=HSC.
[22] IOU-operated gas pipelines are formally referred to as "common carrier" pipelines.
[23] *See*: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201920200AB3163.
[24] Bio-SNG is sometimes referred to as "renewable synthetic natural gas" and is a kind of synthesis gas (Syngas). "Syngas" is a broad term that encompasses multiple different gases produced from multiple different sources–renewable or otherwise–that rely on either steam reforming or gasification for production.
[25] CEC 2017 Integrated Energy Policy Report (IEPR), The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute Low-Carbon Natural Gas for Transportation: Well-to-Wheels Emissions and Potential Market Assessment in California. *See*: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policy-report.

combustion of certain other biofuels, CO_2 emissions from biomethane combustion are tracked separately from fossil fuel combustion emissions.[26]

Capturing biomethane at its source prevents methane emissions from escaping into the atmosphere. Methane released into the atmosphere acts as a potent SLCP[27] with a global warming potential (GWP)[28] 25 times greater than CO_2 over a 100-year period[29] and 84 times greater than CO_2 over a 20-year period.[30] When captured and not released, the emission may be avoided. If that methane is instead combusted, it will result in CO_2 emissions, rather than methane emissions, and therefore have a greatly reduced GWP.[31] Producing biomethane for pipeline injection is one way to capture methane that otherwise might be vented or flared[32] so that it can instead be used as an alternative to fossil natural gas. According to a 2021 UN study, "[r]educing human-caused methane emissions is one of the most cost-effective strategies to rapidly reduce the rate of warming and contribute significantly to global efforts to limit temperature rise to 1.5°C" and "[t]he growing human-caused emissions come from… fossil fuels, agriculture and waste."[33] Additionally, the

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[26] "California's annual statewide greenhouse gas (GHG) emission inventory is an important tool for establishing historical emission trends and tracking California's progress in reducing GHGs. In concert with data collected through various California Global Warming Solutions Act (AB 32) programs, the GHG inventory is a critical piece in demonstrating the state's progress in achieving the statewide GHG target. The inventory provides estimates of anthropogenic GHG emissions within California, as well as emissions associated with imported electricity; natural sources are not included in the inventory. CARB is responsible for maintaining and updating California's GHG Inventory per H&SC section 39607.4." *See*: https://ww2.arb.ca.gov/ghg-inventory-data.

[27] According to CARB, "Short-lived climate pollutants (SLCP) are powerful climate forcers that have relatively short atmospheric lifetimes. These pollutants include the greenhouse gases methane and hydrofluorocarbons, and anthropogenic black carbon. Because SLCP impacts are especially strong over the short term, acting now to reduce their emissions can have an immediate beneficial impact on climate change and public health." *See*: https://ww2.arb.ca.gov/our-work/programs/slcp.

[28] According to the United States Environmental Protection Agency, "The Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO_2). The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that time period. The time period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases." *See*: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.

[29] CARB SLCP Reduction Strategy at 42 (2017) https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf. *See* also International Panel on Climate Change (IPCC) Fourth Assessment Report https://www.ipcc.ch/report/ar4/syr/.

[30] *See* International Panel on Climate Change's Fifth Assessment Report https://www.ipcc.ch/report/ar5/syr/ and the Environmental Protection Agency https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.

[31] Incomplete combustion, however, creates other SLCPs such as Black Carbon. The types of facilities that produce short-lived climate pollutants, especially methane, are described in CARB's 2017 SLCP Reduction Strategy: wastewater treatment facilities, landfills, agricultural waste sites, and dairies. *Supra* at 29.

[32] According to the United States Environmental Protection Agency, combustion efficiency for methane flares is approximately 98 percent. Thus, methane flares release approximately two percent of methane under optimal conditions. The efficiency rate can decrease based on changing conditions such as wind speed and methane flow rate. *See*: https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf.

[33] United Nations Environment Programme and Climate and Clean Air Coalition (2021). Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions. Nairobi: United Nations Environment Programme at 8 and 11. *See*: https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions.

waste byproduct of biomethane production can often be turned into biosolids,[34] biochar, or digestate, some of which can then be used as a soil amendment that sequesters carbon in the ground and reduces reliance on chemical fertilizers that are produced using fossil fuels.[35]

This "Background" section of the Staff Proposal provides detailed information that is needed to determine whether the CPUC should adopt a biomethane procurement program. First, Staff address how gas service is regulated and the role of regulation in procurement decisions. Second, Staff address how the CPUC and other state agencies have implemented policies in recent years to facilitate pipeline injection of biomethane. Third, Staff address existing incentives at the state and federal levels for use of biomethane as transportation fuel. Finally, Staff address the role that CARB's Cap-and-Trade program plays in determining appropriate biomethane procurement prices.

2.1 Understanding Gas Service Regulation

The CPUC regulates California gas IOUs pursuant to Article XII of the California Constitution. Section 3 of Article XII establishes what constitutes a CPUC-regulated public utility and PU Code Section 216(a)(1) explicitly affirms CPUC jurisdiction over gas corporations. PU Code Section 222 defines gas corporations as "every corporation or person owning, controlling, operating, or managing any gas plant for compensation," and PU Code Section 221 clarifies that gas plants include "all real estate, fixtures, and personal property, owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas, natural or manufactured." "Gas corporation" and "gas IOU" are synonymous terms.

IOU-operated pipelines provide gas service to the vast majority of California customers. In 2021, California's gas IOUs are forecasted to deliver approximately 80 percent of all gas consumed in California while the remaining 20 percent will never enter an IOU-operated gas pipeline and will instead flow directly to large volume "bypass" customers.[36] California's two primary gas IOUs are PG&E and SoCalGas, representing Northern California and Southern California, respectively. Other large gas IOUs (SDG&E and

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34 *See*: https://www.epa.gov/biosolids/basic-information-about-biosolids/.

35 B.P. Singh, A.L. Cowie, R.J. Smernik. Biochar Carbon Stability in a Clayey Soil As a Function of Feedstock and Pyrolysis Temperature. Environ. Sci. Technol. 2012, 46, 21, 11770–11778.

36 2020 California Gas Report located in two locations: https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf and https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr20.pdf at 32.

SWG) and small gas IOUs (Alpine Natural Gas and West Coast Gas) are wholesale customers of the two primary gas IOUs.[37] An additional five publicly owned municipal utilities that the CPUC does not regulate are also wholesale customers of the two primary gas IOUs, the largest being Long Beach Gas & Oil.[38]

There are two different types of IOU gas customers. Residential and small commercial customers are called "core" customers and large commercial, industrial, cogeneration, and utility electric generation customers are called "noncore" customers. While noncore customers represent only a small fraction of all IOU gas service customers (core and noncore combined), they consume approximately 60 percent of all gas delivered via IOU-operated pipelines.[39] Unlike core customers, noncore customers typically use independent or in-house marketers to procure gas on their behalf and schedule the delivery of that gas with an IOU.[40] Another distinguishing factor between core and noncore customers is that noncore service has a lower reliability standard and is more likely to be curtailed (*i.e.,* the provision of gas is not guaranteed and may stop with short or no notice).[41] When the gas system is constrained because of weather events, high demand, or system outages, noncore customers are the first gas purchasers to have their gas service curtailed. This is important in order to maintain gas reliability for core customers. The gas IOUs try to avoid ever curtailing residential core customers because a qualified gas professional must re-light every curtailed household's pilot light, a costly and complicated process.

Gas is a deregulated commodity, but the transportation of gas is regulated at the federal and state levels. The CPUC does not determine what price the gas IOUs or CTAs pay to procure the gas used to serve core customers. Noncore customers arrange for their own gas procurement. A gas IOU's Core Procurement Group[42] purchases gas supplies for core customers and arranges bundled transportation and storage of that gas at prevailing market rates through long-term contracts for firm transportation and supplies. Spot market purchases and unbundled transportation and storage are made as needed and those

[37] *Id.* at 31.
[38] The other four are City of Coalinga, City of Palo Alto, City of Vernon, and Island Energy, which serves customers on Mare Island in the City of Vallejo.
[39] 2020 California Gas Report located in two locations: https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf and https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr20.pdf.
[40] Natural gas marketers buy and sell natural gas when the commodity is not sold in a long-term contract. *See*: http://naturalgas.org/naturalgas/marketing/.
[41] Core service is "firm" (*i.e.,* it is reliable even in times of system stress and will always be available except in rare instances of unforeseeable circumstances).
[42] Different gas IOUs use different names for the group that serves this function. For example, SoCalGas calls it the "Gas Acquisition Department" and PG&E calls it "Core Gas Supply."

costs are passed onto noncore customers.[43] However, while the CPUC does not usually direct gas procurement decisions, it still decides whether the gas IOUs have taken reasonable steps to minimize the cost of gas procured on behalf of their core customers. The CPUC established an incentive mechanism[44] that helps ensure that the IOUs procure gas at prices that are close to or lower than average market prices. An IOU's failure to procure reasonably priced gas for its core customers results in shareholders bearing a percentage of the excess costs.

The CPUC's regulatory jurisdiction effectively begins at the point of pipeline injection. While the CPUC does not regulate the production of gas, it does regulate minimum safety standards for the gas that can be injected into an IOU-operated gas pipeline, as well as the cost of transporting that gas from the point of injection to end-user delivery through its transmission and distribution systems. The cost of safe and reliable transportation of gas to core customers is higher than the cost of the gas commodity itself. The CPUC scrutinizes any costs associated with the operation and maintenance of gas IOU pipelines and, if deemed reasonable, approves those costs in a General Rate Case (GRC). The authorized revenue requirement is allocated to the gas IOUs' various customer classes and gas "transportation rates" are fashioned to enable recovery of those allocated amounts.[45] Until recently, considerations regarding gas quality related solely to the fossil natural gas that currently makes up all but a negligible amount of the gas provided to non-transportation core customers. Recent legislation, however, opened the door to gas IOUs procuring biomethane instead of fossil natural gas as part of a strategy to reduce GHG emissions.

2.2 Biomethane Policy Development in California

The enactment of AB 1900 (Gatto, 2012) launched a collaborative effort across multiple state agencies that resulted in the CPUC adopting standards for safe pipeline injection of biomethane. AB 1900 required OEHHA and CARB, in collaboration with other departments within the California Environmental Protection Agency (CalEPA), to compile a list of constituents of concern found in biogas and determine health protective levels for those constituents of concern under realistic exposure scenarios. Those findings

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[43] Core customers also have the option to receive gas procured by a CTA instead of by their IOU. Customers opting to receive gas from a CTA are still usually billed by an IOU and pay an IOU for non-procurement costs. *See* https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPDNaturalGasMarketEconomicRegulation.pdf at 8.

[44] PG&E uses the term Core Procurement Incentive Mechanism (CPIM) and SoCalGas uses the term Gas Cost Incentive Mechanism (GCIM). *See*: https://www.publicadvocates.cpuc.ca.gov/general.aspx?id=736.

[45] Core customer classes might be, for example: residential, small commercial, and natural gas vehicle customers. Noncore customer classes might be, for example: industrial, electric generation, etc. *See* https://www.cpuc.ca.gov/general.aspx?id=4802.

were used to determine appropriate concentrations of constituents of concern, as well as reasonable and prudent monitoring, testing, reporting, and recordkeeping requirements for each source of biogas, and was then reported to the CPUC as a compendium of recommendations.[46]

The CPUC launched Phase 1 of R.13-02-008 to consider the recommendations provided in the OEHHA/CARB report. On January 16, 2014, the CPUC adopted D.14-01-034,[47] approving the recommendations of OEHHA and CARB concerning 12 constituents of concern.[48] Standards for an additional five constituents of concern[49] were added at the request of the gas IOUs to help protect the integrity of the gas pipeline system. D.14-01-034 also established a new mechanism by which to update biomethane injection standards, which AB 1900 requires every five years after December 31, 2013.

The CPUC has concluded two subsequent phases of R.13-02-008 since D.14-01-034 was issued and adopted numerous follow-on decisions. In Phase 2 of R.13-02-008, the CPUC adopted D.15-06-029,[50] resolving various cost considerations associated with complying with biomethane injection standards and creating a $40 million monetary incentive program for both individual biomethane projects and dairy cluster biomethane projects that successfully interconnect with an IOU-operated gas pipeline.[51] The monetary incentive program was created to help lower pipeline interconnection costs, which are expensive and pose a barrier to market entry for new biomethane projects. AB 2313 (Williams, 2016) subsequently required the CPUC to increase the program's monetary incentive from $1 million to $3 million for individual biomethane projects and from $3 million to $5 million for dairy cluster biomethane projects.[52]

Phase 3 of R.13-02-008 saw the CPUC adopt four additional decisions. D.19-05-018 required that the gas IOUs submit a standard biomethane interconnection tariff and adopted recommendations made by the California Council on Science and Technology (CCST) regarding reducing the heating value standard for

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[46] "Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biogas into the Common Carrier Pipeline" (2013) https://oehha.ca.gov/media/final_ab_1900_staff_report_appendices_051513.pdf.
[47] *See*: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K466/86466318.PDF.
[48] OEHHA and CARB's final constituents of concern list comprises of 12 constituents of concern. They are: arsenic, p-Dicholorobenzene, Ethylbenzene, n-Nitroso-din-propylamine, vinyl chloride, antimony, copper, H_2S, lead, methacrolein, alkyl thiols (mercaptans), and toluene. An additional five constituents of concern discussed in D.14-01-034 are: ammonia, biologicals, hydrogen, mercury, and siloxanes. *See* D.14-01-034 at 86. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K466/86466318.PDF.
[49] These include ammonia, biologicals, hydrogen, mercury, and siloxanes.
[50] *See*: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K572/152572023.PDF.
[51] A dairy cluster project refers to a number of dairies pooling their manure resources and piping it to a central upgrading and pipeline injection facility.
[52] The CPUC adopted this new legislation in D.16-12-043 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K303/171303439.PDF.

pipeline gas.[53] D.19-12-009 established a reservation system for the biomethane monetary incentive program. D.20-08-035 adopted a Standard Renewable Gas[54] Interconnection (SRGI) Tariff to harmonize pipeline injection regulation across California's four large gas IOUs, reduce risk and uncertainty for producers, and ultimately lower overall costs. Finally, D.20-12-031 adopted an SRGI Agreement as a companion to the SRGI Tariff, doubled the monetary incentive program from $40 million to $80 million, and clarified various ambiguities from prior decisions.

Additional biomethane-related considerations were taken up outside of R.13-02-008. SB 1383 directed the CPUC to develop recommendations to increase the production and use of in-state biomethane, consider adopting additional incentives, and develop at least five dairy biomethane pilot projects. The dairy biomethane pilot project development process began with the launch of R.17-06-015. In collaboration with CARB and the California Department of Food and Agriculture (CDFA), the CPUC published a pilot project solicitation, received project applications, and selected six projects to develop. These projects are currently in the development and construction process and are all expected to come online in either 2021 or 2022.[55]

On February 28, 2019, SDG&E and SoCalGas jointly filed Application (A.) 19-02-015 requesting authorization to offer a Voluntary Renewable Natural Gas Tariff (VRNGT) program that would allow eligible residential and non-residential customers to replace all or some of their fossil natural gas consumption with biomethane instead. On December 17, 2020, the CPUC voted to adopt a modified VRNGT program that incorporates biomethane procurement targets that are in line with the requirements of SB 1440.[56] The goal of the adopted VRNGT program is to accelerate the use of biomethane, develop biomethane supplies, and reduce SLCPs and other GHG emissions in California. Having a pilot program in advance of the implementation of SB 1440 may help the gas IOUs and their customers gain experience in using biomethane as part of gas service, expand upon the existing biomethane market in California, and provide the CPUC with valuable information to inform future statewide biomethane procurement policies.

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53 CCST "Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications" https://ccst.us/wp-content/uploads/2018biomethane.pdf.
54 As long as a gas meets pipeline quality standards, the CPUC must permit the gas produced to interconnect with the pipeline system. For this reason, the CPUC uses the broad term "renewable gas" to encompass all types of non-fossil gas products produced from various types of renewable resources and technologies, rather than just biomethane.
55 *See*: https://www.cpuc.ca.gov/general.aspx?id=6442455827#dairy_biomethane_pilot_projects.
56 D.20-12-022 Adopting Voluntary Pilot Renewable Natural Gas Tariff Program, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M356/K268/356268059.PDF at 17.

The biomethane policy development that has occurred thus far has resulted in a steady uptick of California biomethane producers successfully injecting into IOU-operated gas pipelines. Those injections, however, have focused overwhelmingly on providing biomethane as a transportation fuel rather than for the benefit of gas IOU core customers. The federal and state programs to encourage biomethane production and use have created a profitable, albeit volatile, market that has encouraged innovation and construction in a bourgeoning renewable fuels industry.

2.3 Biomethane Incentives for Transportation Fuel

To increase the production and use of renewable fuels in the transportation sector, both the United States Environmental Protection Agency (EPA) and CARB established incentive programs. EPA created the Renewable Fuels Standard (RFS), and CARB created the LCFS. Both programs provide monetary compensation for fuels that reduce GHG emissions. These programs have proven to be highly effective and work in parallel at encouraging greater use of renewable fuels.

EPA developed the RFS program under the Energy Policy Act of 2005. The RFS program requires oil and gas refiners and exporters to secure specific volumes of renewable fuel. There are different volume mandates each year, and the program creates specific volume requirements for advanced biofuels and cellulosic biofuels. The RFS uses a "well-to-wheel"[57] analysis to analyze the overall lifecycle GHG impacts of a fuel. EPA divides the various renewable fuels produced into buckets. Each bucket is assigned a renewable identification number (RIN) credit for value, which operates as a "currency" in the program. Under the RFS, biomethane counts toward the cellulosic biofuel volume obligations (D3 RINs). Refiners are required to obtain a specific number of RINs to demonstrate compliance with the standard and these credits are traded on the market, with the credit price set by the marginal cost of compliance (*i.e.,* the cost of producing and obtaining an additional volume of renewable fuel). For cellulosic biofuels, the cost of injecting biomethane into the pipeline, as well as the credit price cap, set the prevailing market price.[58]

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[57] Well-to-wheel analysis accounts for energy emissions from the well pump to the vehicle technology (e.g., tail pipe emissions and energy efficiency of the vehicle. *See*: https://www.epa.gov/renewable-fuel-standard-program/lifecycle-analysis-greenhouse-gas-emissions-under-renewable-fuel.

[58] RINs categorize fuel types according to feedstock source and GHG reduction requirement. For example, D3 fuels are: Cellulosic ethanol, cellulosic naphtha, cellulosic diesel, Bio-CNG, etc. D5 fuels are: Sugarcane ethanol, renewable heating oil, biogas, etc. US Department of Energy "An Introduction to the Renewable Fuel Standard & the RIN Credit Program" https://cleancities.energy.gov/files/u/news_events/document/document_url/84/2_-Session_0_-_RIN_101_-_FINAL.pdf.

The RFS program rules are intended to replace or reduce the use of petroleum-based transportation fuel, heating oil, or jet fuel using renewable alternatives. The program expanded in 2007[59] to include explicit definitions of renewable biomass fuels, increase long-term goals to 36 billion gallons of renewable fuel per year, extend yearly minimum volume requirements out to 2022, authorize the EPA administrator to establish minimum volumes requirements after 2022, and more. On a monthly basis, biomethane producers submit to EPA their renewable fuel production numbers to generate associated RINs in the EPA system.

California's own transportation fuel policy, the LCFS, is one of nine discrete early action measures CARB put into place to reduce GHG emissions pursuant to the AB 32 Scoping Plan.[60] The LCFS targets GHG emissions that can be reduced through the procurement and use of low carbon fuel substitutes in the transportation sector. The LCFS is a market-based credit generating program that was adopted in 2009. It commenced operation in 2011 and has undergone periodic updates to improve carbon intensity values and better facilitate deployment of alternative fuel technologies, including vehicle electrification.[61] The LCFS applies to a variety of transportation fuels, including electricity, gasoline, diesel, and other alternatives such as biomethane and hydrogen. Biomethane production facilities can opt-in to the program to generate LCFS credits by registering a transportation fuel pathway with CARB. Production volume affiliated with this pathway will generate credits relative to the fuel carbon intensity of the pathway, and the carbon intensity standard imposed by the program in a given year. Once LCFS credits are generated, those credits can be sold in the market. Demand for LCFS credits is driven by the deficit-holding entities, which have an obligation to eliminate their deficits to comply with the program. Fuels sold into California with carbon intensities greater than the annual carbon intensity standard will generate deficits.

LCFS credit and deficit generation is related to the carbon intensity of each fuel. Carbon intensity is determined by assessing the GHG emissions produced throughout the lifecycle of the fuel (*i.e.,* emissions from fuel collection, processing, production, and use). LCFS uses the CA-GREET model to assess relevant lifecycle global warming emissions, such as carbon dioxide and methane. The CARB lifecycle assessment includes the direct emissions from producing and using the fuel and the indirect GHG emissions from producing the fuel, as well as emissions from indirect land-use change associated with market-mediated land-use effects from using biofuels. Many factors impact the carbon intensity value, including the source of

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[59] Energy Independence and Security Act of 2007.
[60] CARB LCFS Program website: https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about.
[61] *Id.*

the fuel, the type of feedstock, collection and processing practices, production method, location of production, distance to end-use, and how the fuel is transported and distributed.[62]

Each fuel's carbon intensity is compared against a benchmark carbon intensity number that becomes more stringent every year. Fuels that score below the benchmark number generate credits and fuels that score above the annual benchmark create deficits. The carbon intensity value of the fuel used alongside a vehicle's drivetrain efficiency—the Energy Economy Ratio (EER)[63]—determines the volume of conventional fuel (gasoline, diesel, or alternative jet fuel) that is expected to be displaced by use of the alternative fuel.

CARB's Current Fuel Pathways spreadsheet shows each renewable fuel accepted into the LCFS program and its corresponding carbon intensity score.[64] The carbon intensity of gasoline, for example, is 100.82 grams of CO_2e per MJ. Diesel, at 100.45 grams of CO_2e per MJ, has a slightly lower score. Currently, fossil natural gas used as transportation fuel, once EER-adjusted, scores 81.01 grams of CO_2e per MJ of diesel displaced.[65] Electricity used as transportation fuel, once EER-adjusted, if generated from the California electricity grid, has a carbon intensity of 24.39 grams CO_2e per MJ of gasoline displaced for light-duty vehicle applications and 16.58 grams CO_2e per MJ of diesel displaced for heavy-duty vehicle applications according to the 2020 LCFS Fuel Pathways data.[66] Electricity generated from zero-carbon renewable sources and used as transportation fuel has a carbon intensity of zero, while negative-carbon electricity sources can generate negative carbon intensity scores.[67]

Negative carbon intensity values are possible when production and use of a fuel ends up displacing emissions that might otherwise be emitted under a counterfactual scenario. For instance, if methane would be produced and vented due to waste disposal, redirecting that waste toward the fuel market would avoid fugitive methane emissions. Since many biomethane production pathways can result in avoided methane

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[62] ICF, for the American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," (December 2019) https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf at 70-71.

[63] Distance an alternative-fueled vehicle travels divided by the distance an internal combustion engine vehicle travels using the same amount of energy.

[64] https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.

[65] *See* ARB Table 7-1 Lookup Table for Gasoline and Diesel and Fuels that Substitute: https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/ca-greet/lut.pdf?_ga=2.26292541.1633678091.1602375692-1855556341.1587406624.

[66] *See*: https:/ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/elec_update.pdf.

[67] *See* ARB Table 7-1 Lookup Table for Gasoline and Diesel and Fuels that Substitute: https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/ca-greet/lut.pdf?_ga=2.26292541.1633678091.1602375692-1855556341.1587406624.

emissions, there are numerous pathways where negative scores occur. A range of biomethane carbon intensity scores from pathways currently approved in the program are listed in Table 1. The carbon intensity score varies according to a fuel's EER and lifecycle analysis. Thus, the EER-adjusted carbon intensity value can vary. For instance, biomethane can be used in a fuel cell to generate electricity to power an electric vehicle – this would have a very different EER compared to injecting the biomethane into a pipeline and then withdrawing that biomethane for use in a natural gas vehicle.

Table 1: Carbon Intensities by Feedstock Type (EER-adjusted)[68]

Feedstock Type	Carbon Intensity (gCO_2e/MJ)
Landfill Biogas	-31 to 93
Wastewater Treatment Facility Biogas	8 to 64
Diverted Food/Green Waste Biogas	-20 to 0
Dairy Biogas	-479 to -68

All eligible fuels must be used in the transportation sector in California to generate an LCFS credit. For biomethane, producers can inject their product into an IOU-operated gas pipeline, or generate electricity through a grid-tied system. CARB's "Book and Claim" system under the LCFS program permits a biomethane and electricity quantities to be matched to fuel-use quantities within a three-quarter period from when the biomethane is "booked" to when it is "claimed" to ensure that dispersed physical gas or electric vehicle charging data matches the biomethane volumes injected or converted to electricity. LCFS credits are generated on a quarterly basis and are based on dispensed volumes of fuel. A biomethane producer is permitted to apply for and receive credits in both the federal RFS program and CARB's LCFS program, and operating under the rules of both programs does not constitute double counting.

California's largest gas IOUs currently participate in the LCFS market. In 2018, PG&E,[69] SDG&E, and SoCalGas[70] asked for and received permission to run a three-year pilot project to procure biomethane at volumes equivalent to fossil natural gas dispersals at their compressed natural gas (CNG) pumping stations.

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[68] CARB LCFS Current Fuel Pathways spreadsheet. See: https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.
[69] AL 3961-G https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_3961-G.pdf.
[70] *See*: https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/5295.pdf.

Contracts signed to date currently cover all gas dispersed at the three IOUs' respective CNG gas pumps (30 PG&E pumps, six SDG&E pumps, and 31 SoCalGas pumps). The credit sharing agreement allows vehicles filling up at PG&E pumps to receive renewable CNG (Bio-CNG) at cost parity with fossil CNG and vehicles filling up at SDG&E and SoCalGas pumps to receive Bio-CNG and pay less for a tank of fuel than they would for fossil CNG. This Bio-CNG is considered core procurement, but these pilots do not have an impact on the rates of gas IOUs' core customers because the programs' purchase and sale of biomethane into the transportation sector (and credit sharing with producers) covers all costs. Preliminary contracting experiences have helped the gas IOUs identify biomethane producers, contract with them to meet their biomethane needs, and manage credit sharing in the RFS and LCFS markets. Current LCFS and RIN credit price incentives can amount from $30 to over $130 per MMBtu of biomethane when used as a transportation fuel.[71]

2.4 The Role of Cap-and-Trade

California's Cap-and-Trade Program was introduced pursuant to AB 32 (Núñez, 2006), which authorized CARB to develop a market-based mechanism to reduce GHG emissions from certain polluting entities. CARB is required to inventory the total GHG emissions from major GHG sources. The Cap-and-Trade Regulation establishes a declining limit on major sources of GHG emissions throughout California. The Program applies to emissions that cover approximately 80 percent of the state's GHG emissions. CARB creates allowances equal to the total amount of permissible emissions (*i.e.*, the "cap"). One allowance equals one metric ton of carbon dioxide equivalent emissions (using the 100-year global warming potential). Each year, fewer allowances are created and the annual cap declines.[72] This mechanism provides participants in the system with a financial incentive for conservation and investment in higher efficiency technologies as the program advances.

In 2015, at the start of the Cap-and-Trade Program's second compliance period, California's gas IOUs began to incur compliance obligations to CARB for emissions associated with the combustion of fossil natural gas delivered to residential customers and other small-scale users, and all other entities not directly covered by the Cap-and-Trade Program.[73] At the same time, outside of this compliance obligation,

[71] Assuming biomethane with a carbon intensity of 93 gCO_2e/MJ or -479 gCO_2e/MJ, D3 RIN prices of $2.45, and LCFS credit prices of $195.
[72] https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/about
[73] Large-scale users have a direct obligation to CARB.

the four large gas IOUs that are subject to the Cap-and-Trade Program regulation (*i.e.,* PG&E, SDG&E, SoCalGas, and SWG) each began to be annually allocated an amount of no-cost allowances equal to their respective compliance obligation in 2011 multiplied by a "cap adjustment factor" (0.817 in 2021). The cap adjustment factor declines each year in proportion to the overall annual emission caps.[74] These allowances are provided to these gas IOUs for ratepayer protection. The Cap-and-Trade Regulation also places requirements on how the allocated allowance value may be used. Gas IOUs are required to consign a minimum percentage of their allocated allowances to quarterly Cap-and-Trade Program auctions each year. This minimum percentage increases by five percent each year and will reach 100 percent in 2030. The CPUC directed gas IOUs to return proceeds from the sale of allocated allowances to residential ratepayers as the annual California Climate Credit. After consigning the minimum percentage to auction, gas IOUs may use the remaining allocated allowances for Cap-and-Trade Program compliance, thus reducing compliance costs.

Each gas IOU must acquire and surrender a compliance instrument (*i.e.,* an allowance or an offset credit) to satisfy any remaining compliance obligation, and in D.14-12-040,[75] CPUC directed gas IOUs to pass on these Cap-and-Trade Program compliance costs to customers. Gas IOUs may not use offset credits to satisfy more than four percent of their compliance obligations resulting from emissions from January 1, 2021 to December 31, 2025. Allowances that may be purchased at CARB's quarterly auctions that happen each year in February, May, August, and November or acquired through secondary markets and other avenues allowed by the Cap-and-Trade Regulation. While CARB's auctions include a price floor price that increases each year by five percent plus the rate of inflation, secondary markets do not have a minimum price.

Gas IOU compliance with the Cap-and-Trade Program has a direct impact on customer rates. D.14-12-040[76] directs the amount that the gas IOUs ultimately pay to meet their compliance obligations to pass directly to their customers (including industrial, small business, and residential customers) as part of the transportation component of their bills. The California Climate Credit is provided annually in April to gas IOUs' residential customers to offset increased compliance costs on their bills. California Climate Credits are funded by proceeds come from the sale of allowances allocated to gas IOUs consigned to Cap-an-Trade

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[74] Baseline emissions for 2011 for the large natural gas IOUs were (in metric tons of CO_2e): 20,020,720 for PG&E, 3,203,170 for SDG&E, 23,292,911 for SoCalGas, and 771,823 for SWG.
[75] *See* D.14-12-040 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K633/143633560.PDF.
[76] *See* D.14-12-040 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K633/143633560.PDF.

Program auctions each year.[77] Initially, 100 percent of allowance proceeds were returned to residential customers, but subsequent legislation and CPUC decisions have resulted in a portion of allowance proceeds being allocated for programmatic purposes. Residential customers receive the vast majority of all auction proceeds from the sale of allowances allocated to gas IOUs through the California Climate Credit. Non-residential customers who do not have a direct Cap-and-Trade Program compliance obligation do not receive any climate credits, but they do pay for the Cap-and-Trade Program compliance costs in rates.[78]

Biomethane procurement reduces a gas IOU's Cap-and-Trade Program compliance obligations. Because CO_2 emissions from specific biomass-derived fuels are exempt from a compliance obligation under Cap-and-Trade, California's gas IOUs do not have to surrender allowances or offset credits for the emissions associated with biomethane procured in a manner that meets Cap-and-Trade Program requirements[79] and is supplied to their core customers. As such, if the gas IOUs were theoretically able to use 100 percent biomethane to serve their core customers, they would have very low compliance obligations under the Cap-and-Trade Program.[80] Fewer compliance obligations translate to less cost that is passed on to core customers. Accordingly, any consideration of biomethane procurement levels must take into account not only the increased cost associated with procuring biomethane compared to fossil natural gas, but also the potential decrease in Cap-and-Trade Program compliance costs borne by ratepayers, even if the potential decrease in cost is small relative to the commodity cost of biomethane.

[77] The percentage of allowances consigned to auction was 25 percent in 2015 and increases five percent each year until 2030.
[78] Large facilities that emit more than 25,000 metric tons of CO_{2e} per year have a direct compliance obligation to CARB. For these deliveries, natural gas IOUs do no purchase compliance instruments on behalf of the end-user. As a result, Cap-and-Trade compliance costs passed onto these customers are significantly lower and only cover emissions associated with lost gas and company facilities such as pipeline compressor stations.
[79] Biomethane is only exempt from a compliance obligation if it meets requirements listed in section 95852.1.1 of the Cap-and-Trade Regulation. Biomethane from in-state production or from new or expanded out-of-state sources may meet those requirements.
[80] Only CO_2 emissions from biomethane that is procured in a manner that meets CARB requirements is exempt from a compliance obligation. Combustion CH_4 and N_2O emissions do incur a compliance obligation under the Cap-and-Trade Program. However, these emissions represent approximately 0.1 percent of total CO_2e.

3 Challenges

SB 1440 requires the CPUC to ensure that any biomethane procurement program it adopts is consistent with SB 1383's methane reduction goals. PU Code Section 651(a)(1) specifies that any biomethane procurement program must be a cost-effective means by which to reduce statewide methane emissions by 40 percent below 2013 levels by 2030. PU Code Section 651(b)(1) further requires the CPUC to consider the CEC's recommendations developed pursuant to California Health and Safety Code Section 39730.8.[81] The CEC's 16 recommendations, which are included in its 2017 Integrated Energy Policy Report (IEPR), target multiple state agencies and focus on goals such as maximizing GHG emissions reductions, avoiding harm to disadvantaged communities, developing commercial markets for biomethane, providing market certainty for biomethane producers, promoting biomethane production over venting or flaring, and diverting organic waste from landfills for the purpose of biomethane production.[82]

Landfill diversion is an explicit focus of SB 1440. PU Code Section 651(b)(2) requires the CPUC to ensure that any biomethane procurement program it adopts complements the organic waste disposal reduction targets specified in California Health and Safety Code Section 39730.6[83] and the regulations adopted pursuant to California Public Resources Code Section 42652.5[84] to achieve those targets. Those regulations require a 50 percent reduction in the level of statewide disposal of organic waste from the 2014 level by 2020 and a 75 percent reduction in the level of statewide disposal of organic waste from the 2014 level by 2025. On August 18, 2020, CalRecycle reported that California would not meet its landfill diversion goals for 2020 and will have less than 56 percent of the capacity needed to meet its goals for 2025.[85]

An important final requirement of SB 1440 is for the CPUC to ensure that any biomethane adopted in a procurement program and delivered through an IOU-operated gas pipeline provides one or more environmental benefits to California. According to PU Code Section 651(b)(3)(B)(ii),[86] environmental benefits include: (1) the reduction or avoidance of the emission of any criteria air pollutant, toxic air contaminant, or GHG in California; (2) the reduction or avoidance of pollutants that could have an adverse

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[81] *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=39730.8.&lawCode=HSC.
[82] *See*: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policy-report at 284.
[83] *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=39730.6.&lawCode=HSC.
[84] *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=42652.5.&lawCode=PRC.
[85] *See*: https://www2.calrecycle.ca.gov/Publications/Download/1589. Table 1 at 7.
[86] *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=651.&lawCode=PUC.

impact on California waters; and (3) the alleviation of a local nuisance within California that is associated with the emission of odors. As such, any CPUC-adopted biomethane procurement program must focus on California-based sources of biomethane unless the source directly results in at least one of the forementioned environmental benefits to California. By including environmental benefits beyond just GHG emissions reductions, SB 1440 encourages consideration of ways in which biomethane production can improve the health, safety, and comfort of communities from which biomethane is sourced.

This "Challenges" section of the Staff Proposal focuses on various challenges associated with procuring biomethane in a way that meets the requirements of SB 1440. First, Staff address how biomethane procurement could be a tool for helping California supporting environmental justice goals. Second, Staff address how to determine cost-effectiveness in the context of biomethane procurement. Third, Staff address the current prices and availability of biomethane. Finally, Staff address the potential of various different sources of biomethane to meet California's climate goals.

3.1 Emphasizing Environmental Justice

Many of the facilities that could potentially supply California with biomethane also raise concerns about environmental justice. Environmental justice is defined as "the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation and enforcement of environmental laws, regulations, and policies."[87] Biogas sources such as wastewater treatment facilities, dairies, and landfills are often located in disadvantaged communities. These facilities either emit fugitive waste methane gas directly into the atmosphere, burn it for electricity generation, flare it, produce renewable natural gas vehicle fuel, or inject biomethane into the natural gas pipeline system. A CEC study found that "biogas and biomethane combustion exhaust is similar to natural gas combustion exhaust."[88] Emitting, burning, and flaring methane all negatively impact local air quality, resulting in negative health impacts such as increased mortality and morbidity, adverse effects on reproductive health, and birth defects.[89,90] Many

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87 California Government Code Section 65040.12(e).

88 Kleeman, Michael J., Thomas M. Young, Peter G. Green, Stefan Wuertz, Ruihong Zhang, Bryan Jenkins, Norman Y. Kado, and Christopher F.A. Vogel. 2020. Air Quality Implications of Using Biogas to Replace Natural Gas in California. California Energy Commission. Publication Number: CEC-500-2020-034 at 128 https://ww2.energy.ca.gov/2020publications/CEC-500-2020-034/CEC-500-2020-034.pdf.

89 CalEPA and OEHHA CalEnviroScreen 3.0 (2017) at 104. https://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf.

90 CARB regulates landfill methane emissions. *See*: https://ww2.arb.ca.gov/sites/default/files/2020-06/landfillfinalfro.pdf.

facilities also produce non-gaseous effluent waste that can contaminate local water sources.[91] The CPUC tries to mitigate some of this harm through its Environmental and Social Justice Action Plan.[92]

Using biogas for biomethane production reduces methane emissions, creates waste byproduct to reuse or sell that can help recover costs, and creates local jobs. Injecting biomethane into IOU-operated gas pipelines not only displaces fossil natural gas use, but it can also decrease localized criteria air pollutants by reducing methane flares and on-site combustion for electricity generation.[93] Use of biomethane to replace fossil natural gas can have environmental benefits because fossil natural gas produces the same combustion products without any of the SLCP or carbon emissions reductions available through biomethane production pathways. In a broader sense, GHG emissions reductions on a large statewide level will contribute to incremental global GHG reductions that are needed to help mitigate natural disasters associated with climate change such as flooding, coastal erosion, hurricanes, wildfires, heat waves, water insecurity, and food insecurity.[94] Disadvantaged communities face more exposure to climate-related damage and have more difficulty in rebuilding after disasters ravage a region.[95]

Some of the environmental harm caused by dairy operations can be partly mitigated through biomethane production. Environmental justice advocates in California generally oppose dairy biomethane production because "communities in the vicinity of dairies are already disproportionately burdened by environmental pollution, and community members feel strongly that developing RNG at dairies will perpetuate their adverse environmental impacts on the local community, may allow dairies to continue causing pollution (other than GHG emissions) and may facilitate expansion of dairies, even increasing the local environmental burdens."[96] Methane emitted through enteric fermentation cannot be captured as readily as methane emitted from manure. Manure methane emissions represent 26 percent of the California's total methane emissions and enteric fermentation emission represent 28 percent. Total livestock methane

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[91] Patterson, Doug. "The Central Valley Water Board." Presentation at the July 29, 2020, IEPR workshop on Near-Zero Emission Vehicles and Low-Carbon Fuels. https://efiling.energy.ca.gov/GetDocument.aspx?tn=234043&DocumentContentId=66871.
[92] *See*: https://www.cpuc.ca.gov/esjactionplan/.
[93] Marc Carreras-Sospedra, Robert Williams & Donald Dabdub (2016) Assessment of the emissions and air quality impacts of biomass and biogas use in California, Journal of the Air & Waste Management Association, 66:2, 134-150 at 136, https://www.tandfonline.com/doi/full/10.1080/10962247.2015.1087892.
[94] UN Department of Economic & Social Affairs Working Paper No. 152, "Climate Change and Social Inequality" (2017) https://www.un.org/esa/desa/papers/2017/wp152_2017.pdf.
[95] Disadvantaged vulnerable community (DVC) is defined as "[t]he communities most vulnerable to climate change." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K285/346285534.PDF.
[96] D.20-12-022 at 37, referencing D.17-12-004 (dairy pilot program) and D.15-06-029; D.16-12-043; and D.19-12-009 (biomethane interconnection incentive program). CPUC concluded in program marketing materials that it would not portray biomethane as a solution to local environmental impacts of dairies or other biomethane sources and that it would disclose that capturing biogas "does not mitigate all water, air, and odor pollution from dairies that impacts local communities."

emissions are approximately 54 percent of all methane emissions in California.[97] Thus dairy biomethane can, at best, capture approximately half of the emissions from dairies. Even though biomethane is not a comprehensive solution to dairies' local environmental impacts, a 2005 study of San Joaquin Valley dairy biomethane concludes that as "large dairies become more common, the pollution potential of these operations, if not properly managed, also increases. The potential for the leaching of nitrates into groundwater, the potential release of nitrates and pathogens into surface waters, and the emission of odors from storage lagoons is significantly reduced with the use of anaerobic digestion. There may also be a reduction in the level of volatile organic compound (VOC) emissions."[98] According to a meta-analysis of 30 dairy farm anaerobic digester studies, anaerobic digestion (AD) "has a triple benefit of: (i) converting high global warming CH_4 to CO_2; (ii) generating energy that substitutes fossil fuels; and (iii) producing digestate that replaces mineral fertilizers. Consequently, implementing AD [for biomethane production] offers farmers a management system for their excess nutrients (i.e., nitrogen and carbon species) and can create profitable products." This study concluded that with outliers removed, anaerobic digestion reduces methane emissions by 90.6 percent (median) with respect to untreated manure.[99] The meta-analysis further showed a 43.2 percent median emissions reduction due to anaerobic digestion slurry storage.

Biomethane production can also play a role in reducing the environmental harm associated with landfills. Most California landfills are required to capture fugitive methane emissions. Captured methane is generally burned (either flared or combusted for electricity generation), which emits criteria air pollutants.[100] Landfill odors and leachate (*i.e.,* liquid that exists as part of waste in a landfill) are also problematic, representing both a nuisance and a public health hazard.[101] In a 2004 study "Waiting to Inhale,"[102] 2000

[97] CARB 2017 methane inventory. *See*: https://ww3.arb.ca.gov/cc/inventory/background/ch4.htm.
[98] K. Kirch, et al. "Biomethane from Dairy Waste: A Sourcebook for the Production and Use of Renewable Natural Gas in California" (2005) https://www.academia.edu/download/53763503/Biomethane_from_Dairy_Waste.pdf.
[99] Miranda, Nicole D., Hanna L. Tuomisto, and Malcolm D. McCulloch. "Meta-analysis of greenhouse gas emissions from anaerobic digestion processes in dairy farms." Environmental science & technology 49.8 (2015): 5211-5219. https://pubs.acs.org/doi/abs/10.1021/acs.est.5b00018. .
[100] Kleeman, Michael J., Thomas M. Young, Peter G. Green, Stefan Wuertz, Ruihong Zhang, Bryan Jenkins, Norman Y. Kado, and Christopher F.A. Vogel. 2020. Air Quality Implications of Using Biogas to Replace Natural Gas in California. California Energy Commission. Publication Number: CEC-500-2020-034 at 128 https://ww2.energy.ca.gov/2020publications/CEC-500-2020-034/CEC-500-2020-034.pdf.
[101] Lee, G. F., & Jones-Lee, A. Impact of municipal and industrial non-hazardous waste landfills in public health and the Environment: An overview. Prepared for California EPA Comparative Risk Project. Sacramento, CA: G. Fred Lee & Associates (1994) http://www.gfredlee.com/cal_risk.htm.
[102] Pastor, M., Sadd, J., & Morello-Frosch, R. (2004). Waiting to inhale: The demographics of toxic air release facilities in 21st-century California. Social Science Quarterly, 85(2), 420–440. https://doi.org/10.1111/j.0038-4941.2004.08502010.x.

Census and EPA Toxic Release Inventory (TRI) data,[103] were used to show "California racial disparities in proximity to the TRI facilities [including landfills] exist and are persistent even in a multivariate context, even when we control for degree of hazard, and even when we control for potential spatial dependence."[104] In a nationwide study on landfills, "Examining Rural Environmental Injustice," author Clare Cannon found evidence that people of color, particularly African Americans, are disproportionately affected by environmental hazards from landfills.[105] Procuring biomethane from landfills reduces methane flaring and can reduce associated on-site combustion-based nitrogen oxides (NO_x), sulphur oxides (SO_x), ozone (O3), and particulate matter. This reduction in air pollutants near landfills may improve local air quality, decrease local environmental hazards, and may help achieve environmental and social justice goals consistent with state policy, however the captured biomethane will be transported and combusted elsewhere, so the overall impact is unclear.

Communities surrounding wastewater treatment facilities can also benefit from biomethane production in a manner similar to landfills. Wastewater treatment facilities are generally in highly populated areas, with the largest facilities found around the Los Angeles metropolitan area, San Diego, Sacramento, and the Bay Area.[106] A San Francisco Public Utilities Commission (SFPUC) study analyzed the demographics of communities near two wastewater treatment plants in San Francisco. The wastewater treatment plant that processes 80 percent of the city's sewage is in the Bayview-Hunters Point neighborhood. The residents living in the vicinity of that plant "are 48% African American, 28% Asian, 17% Hispanic and 10% White. Nearly a quarter have incomes below the national poverty line, and 16% are unemployed."[107] If there is an incentive for wastewater plants to monetize biogas and sell it as biomethane, or provide a path for biomethane-based (rather than biogas-based) electric generation, emissions reductions

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103 "TRI tracks the management of certain toxic chemicals that may pose a threat to human health and the environment." TRI facilities include disposal: in landfills and surface impoundments that are not regulated under RCRA Subtitle C; to soil (land treatment/application farming); and any other land disposal https://www.epa.gov/trinationalanalysis/land-disposal.

104 Social Science Quarterly Volume 85, Number 2, June 2004 at 436 https://onlinelibrary.wiley.com/doi/abs/10.1111/j.0038-4941.2004.08502010.x.

105 Cannon, C. (2020). Examining rural environmental injustice: An analysis of ruralness, class, race, and gender on the presence of landfills across the United States. The Journal of Rural and Community Development, 15(1), 89–114 https://journals.brandonu.ca/jrcd/article/view/1737/407.

106 Marc Carreras-Sospedra, Robert Williams & Donald Dabdub (2016) Assessment of the emissions and air quality impacts of biomass and biogas use in California, Journal of the Air & Waste Management Association, 66:2, 134-150 at 136, https://www.tandfonline.com/doi/full/10.1080/10962247.2015.1087892.

107 The Oceanside wastewater treatment plant processes 20 percent of the city's sewage and has "no immediate household neighbors." Gen, S., Shafer, H., Nakagawa, M. (2010). Sustainable Development. "Perceptions of Environmental Justice: The Case of a US Urban Wastewater System" https://onlinelibrary.wiley.com/doi/abs/10.1002/sd.458.

would help improve air quality in the vicinity of these plants and thereby promote racial, environmental, and social justice.

3.2 Determining Cost-effectiveness

The CPUC generally requires that ratepayer-funded efforts be cost-effective. In other words, the benefits of any ratepayer funds that are invested in a program, project, or technology must exceed the costs of the investment. This practice protects ratepayers from undue rate increases caused by misguided financial decisions. Traditionally, cost-effectiveness analyses of ratepayer-funded programs were based strictly on financial inputs. For example, energy efficiency efforts were determined to be cost-effective if they were cheaper than building and operating power plants. More recently, however, the imperative to reduce GHG emissions has become a crucial concern, and cost-effectiveness analyses have focused on determining the least-cost method of achieving California's GHG reduction goals, as well as avoiding unnecessary rate increases.

There are no established CPUC rules or regulations for determining biomethane's cost-effectiveness. To determine the cost-effectiveness of biomethane, two factors must be considered: (1) the costs and benefits associated with an investment in renewable natural gas technology from different perspectives and (2) how the net benefit (or cost) compares with other options. Staff look to three frameworks to provide guidance on inputs and an analysis for a cost-effectiveness test: (1) the costs and benefits used for distributed energy resources (DERs),[108] as outlined in D.19-05-019;[109] (2) the methane leak abatement cost-effectiveness analysis adopted in Resolution G-3576 and D.19-08-020; and (3) Oregon's recently approved biomethane procurement program for NW Natural.[110]

In the first framework for cost-effectiveness inputs, DER cost-effectiveness programs, costs, and benefits are estimated from five different perspectives. Those perspectives include: (1) the participant; (2)

[108] DERs are categorized in the IDER proceeding in alignment with PU Code Section 769 which defines distributed resources as renewable generation, energy efficiency, energy storage, electric vehicles, and demand response technologies. *See*: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=769.&lawCode=PUC.
[109] D.19-08-020 states: "[a]lthough D.19-05-019 only addresses cost-effectiveness tests for electricity planning, it shows the direction that the CPUC is taking, and that information about social cost of GHG emissions is useful for evaluation of proposed utility investments." Similarly, we use the DERs cost-effectiveness tests for consistency in CPUC analyses. *See*: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M311/K449/311449621.PDF.
[110] Oregon Public Utility Commission Order No. 20-227 (2020) https://apps.puc.state.or.us/orders/2020ords/20-227.pdf.

the ratepayer;[111] (3) the program administrator (often the utility); (4) a total resource perspective, which combines all of the "investors" (usually the utility and the program participant); and (5) society as a whole.[112] While this framework is a useful approach, not all of these perspectives are applicable to biomethane. Because this is not a DER, there is no program participant. However, because the goal is to enable biomethane producers to enter into contracts with the gas IOUs, the perspective of the producer is somewhat similar to that of a program participant. The total resource perspective does not apply because the utility and the producer are not joint investors in the same equipment. Rather, the producer is investing in the means to produce biomethane and then entering into a contractual relationship with the utility. Additionally, there are no increases or decreases in energy consumption, so there will be no change in the revenues paid to utilities. Any additional costs of producing biomethane will be passed to ratepayers, so additional costs for the gas IOUs and ratepayers will be equal, making a ratepayer perspective identical to a utility/program administrator perspective. The societal perspective analysis takes into consideration the social cost of methane.

Hence, the cost-effectiveness analysis for biomethane procurement focuses on three perspectives: the perspectives of the utility, the biomethane producer, and society as a whole. From the perspective of the utility, the benefits of purchasing biomethane are the value of the avoided carbon allowances or offset credits that would otherwise need to be purchased to comply with Cap-and-Trade Program compliance obligations,[113] and the costs are the sum of the price differential between biomethane and fossil natural gas, as well as any additional gas IOU infrastructure costs required to facilitate a biomethane producer's interconnection to an IOU-operated pipeline. The biomethane producer's perspective will depend on the individual producer's costs and the price they can get for biomethane sales. Finally, the societal perspective will factor in non-economic benefits such as SLCP reductions, air quality improvements, and other environmental benefits enumerated in SB 1440.

One method of determining the societal value of biomethane is by comparing the net cost of a biomethane project to the social cost of methane. CPUC Resolution G-3576[114] and D.19-08-020[115] established a cost-effectiveness method for assessing investments made to help abate natural gas leakage.

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[111] Defined here as the biomethane producer that bears the cost of operating, maintaining, and injecting biomethane into a common carrier pipeline.
[112] D.19-05-019 at 8.
[113] D.19-08-020 uses a "Proxy GHG Allowance Price" instead of carbon allowance for methane leak abatement.
[114] CPUC Resolution G-3576: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M355/K728/355728330.PDF.
[115] D.19-08-020 at 36 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M311/K449/311449621.PDF.

This method compares the Federal Interagency Working Group's (IWG) social cost of methane,[116] estimated to be $29 per thousand standard cubic feet (MSCF) in 2020, per unit of methane reduction using the three percent discount rate (see Table 2).[117] $27/MSCF converts to $26/MMBtu.[118] While this analysis does not help establish cost-effectiveness, it does provide a threshold CPUC can use for procedural review.

Table 2: IWG Interim Social Cost of Methane (in 2007 2020 dollars per MSCF)[119]

Year	5% Average	3% Average	2.5% Average	High Impact (3% 95th Percentile)
2020	$12	$27	$36	$70
2025	$14	$30	$39	$81
2030	$17	$36	$45	$93
2035	$20	$39	$50	$107
2040	$23	$45	$56	$120
2045	$27	$50	$63	$134
2050	$30	$56	$68	$147

The second framework is outlined in the CPUC's methane leak abatement decision (D.19-08-020), which requires the gas IOUs to provide a cost-effectiveness analysis of investments proposed in their biennial "Compliance Plans,"[120] which Resolution G-3576 approved. Methane leak abatement can be similar to biomethane procurement because both investments can help reduce the risk of methane emissions, thus a comparison of costs is logical. In practice, this may not be true because methane leak abatement volumes

[116] In February 2021, IWG prepared interim social cost of methane values until a comprehensive update is issued in January 2022. *See*: Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990," https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

[117] *Id.* at 16. The conversion assumes a typical methane concentration in natural gas of 93.4 percent. The conversion factor is 55.835 MSCF per metric ton of methane at standard conditions of 1 atmosphere and 60 degrees Fahrenheit.

[118] The conversion uses EIA data, with a conversion factor of 1.037 MMBtu per Mcf. *See*: https://www.eia.gov/tools/faqs/faq.php?id=45&t=8.

[119] D.19-08-020 converted the Interagency Working Group's social cost of methane from metric ton to MSCF. The percent values are discount rates, which convert future estimated cost to a discounted value in today's money. The "High Impact" value represents the "lower-probability, but higher-impact outcomes from climate change, which would be particularly harmful to society and thus relevant to the public and policymakers. The fourth value is included to represent the marginal damages associated with these lower-probability, higher-impact outcomes." Accordingly, this value is selected from further out in the tail of the distributions of social cost of methane estimates; specifically, the fourth value corresponds to the 95th percentile of the frequency distributions of social cost of methane estimates based on a three percent discount rate. *See* "Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide" Table 1 at 7 https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf.

[120] D.19-08-020 Ordering Paragraph 1 at 82 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M311/K449/311449621.PDF.

are significantly less than methane emissions from biological sources, therefore the methane leak abatement cost-effectiveness analysis is a framework worthy of investigating but not necessarily copying. In addition to the social cost of methane method described above, the framework used in D.19-08-020 requires one method of determining cost-effectiveness based on a ratio of reasonably quantifiable benefits to costs. For benefits, the test requires fossil gas cost savings and avoided Cap-and-Trade Program costs consideration (*i.e.*, "Proxy GHG Allowance Price"). For costs, considerations include an "appropriate timeframe of analysis—over the life of the asset, compliance period, timeframe for incentive mechanism, etc. including time value of money, discounting, and capital recovery factor." The methane leak abatement decision also applies an avoided social cost of methane, which may not apply to a cost-effectiveness test for biomethane procurement, but it may provide a threshold for CPUC review.

The third and final framework is the Oregon Public Utility Commission's rule, which required that the IOUs develop a cost-effectiveness model for biomethane procurement. One Oregon gas IOU, NW Natural, created a model that uses the capital costs for the biomethane producer as an input, which can ensure the biomethane producer receives, at a minimum, a break-even contract price and ensures the long-term viability of the project. One major difference between Oregon and California is that Oregon has a well-established Integrated Resource Plan (IRP) for its gas IOUs, whereas California does not.[121] As a result, Oregon planned for least-cost and least-risk gas procurement and has specific biomethane procurement targets. Oregon's approach can, however, provide a framework for inputs and modeling methods for California biomethane procurement, even though California does not yet have specific biomethane targets.[122]

Biomethane procurement can be cost-effective when compared to the social cost of methane. The question for the CPUC to consider is whether procurement of some volume of biomethane for core gas customers is a cost-effective way to meet state SLCP reduction targets. Any analysis of biomethane's cost-effectiveness should consider the inputs provided in the three frameworks to determine the least-cost biomethane that provides the most SLCP reduction.

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[121] California has an IRP, but it is electric-focused.
[122] NW Natural 2018 IRP at 414 https://edocs.puc.state.or.us/efdocs/HAA/lc71haa151218.pdf.

3.3 Resource Cost and Availability

Today's low cost of fossil natural gas makes the task of procuring a more expensive resource like biomethane difficult. The cost of fossil natural gas entering California's IOU-operated pipelines from out-of-state—more than 90 percent of current supply[123]—averaged $2.28/MMBtu for SoCalGas and $3.52/MMBtu for PG&E in 2019.[124] According to California's gas IOUs, those prices are forecasted to rise to $2.95/MMBtu for SoCalGas and drop to $3.23/MMBtu for PG&E by 2035, meaning that prices are expected to remain largely the same for the next 15 years.[125] However, fossil natural gas was not always this cheap. Even as recently as 2008, the price core customers paid was $6/MMBtu,[126] and the national market price peaked at $13.32/MMBtu.[127] The downward price trend began around the end of 2008 and has largely been driven by innovations in the gas industry, most notably hydraulic fracturing (*i.e.,* fracking).

Biomethane is a much more expensive resource in comparison to fossil natural gas. For example, in December 2016, the University of California (UC) ran an open solicitation to procure biomethane that resulted in 25 bids from 14 different suppliers, with a median bid price of $13.73/MMBtu.[128] However, the bids UC received were primarily for lower price biomethane sourced from landfills and wastewater treatment facilities located out-of-state. Biomethane from California dairies, which has a much lower carbon intensity than other sources of biomethane, is one of the most expensive biomethane sources commercialized in the market, valued at well over $50/MMBtu when sold as vehicle fuel.[129] If accepted as reasonably accurate gauges of biomethane valuation, $13.73/MMBtu translates to approximately five times today's price of fossil natural gas and $50/MMBtu translates to approximately 20 times today's price of fossil natural gas.

Biomethane procurement, though seemingly cost-prohibitive, may not result in large increases to customer bills. A bill comprises three main components: (1) core procurement costs (2) costs of operating the natural gas transportation system and providing customer services, and (3) costs associated with gas

123 U.S. EIA, Natural Gas Gross Withdrawals and Production, Gross Withdrawals, 2018, Annual.
124 *See*: https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf.
125 *Id.*
126 2008 California Gas Report https://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf.
127 Congressional Research Service used Henry Hub spot price for its national "benchmark" market price. "Natural Gas Markets: An Overview of 2008"at 2 https://www.everycrsreport.com/files/20090331_R40487_8348d09c187681ce176932c2629c0f074be797bd.pdf.
128 *See*: https://www.nceas.ucsb.edu/sites/default/files/2020-02/UC_TomKat_Replacing_Natural_Gas_Report_2018.pdf.
129 BioCycle "101 For Low Carbon Fuel Standard," (2019) https://www.biocycle.net/101-low-carbon-fuel-standard/.

public purpose programs.[130] The commodity cost falls under the first component: core procurement costs. The percent of commodity cost in a ratepayer's bill varies from month to month and generally ranges from 20-25 percent.[131] If a gas IOU were to procure 10 percent of its current natural gas core customer demand from biomethane by 2030, and biomethane costs approximately six times greater than fossil natural gas, then a ratepayer can expect to pay 10-13 percent more on their bill in 2030 vis-à-vis what they pay for gas today. The bill increase will steadily increase over time until the gas IOU reaches that 2030 volumetric target.

An increase in a ratepayer's bills may drive customers from core customer bundled service to unbundled service, as described in Section 2.1, if CTAs are not required to adhere to the same biomethane procurement rules as the gas IOUs. If those CTAs offer low-cost fossil natural gas, then the cheaper rates may attract customers who do not want to pay a higher price for biomethane. The CPUC does not regulate CTA procurement offerings, so there is a risk that CTAs may be able to significantly undercut bundled service rates and, by extension, undermine any biomethane procurement efforts by offering customers the option to return to cheap fossil natural gas procurement if steps are not taken to avoid this outcome.[132]

Further complicating biomethane procurement is the general limit of current availability. Multiple recent studies estimated technical potential biomethane production volumes across the United States, from biomass and other renewable resources. These studies have varied results. For example, a 2017 UC Davis study estimated that in California there is 93 billion standard cubic feet (Bcf) per year (96 million MMBtu/year) "of biomethane potential in 2013—enough to meet about 4.5 percent of an average [year's] demand in California."[133] In 2019, UC Davis updated its biomethane technical potential estimate to 602.4 million MMBtu/year (580.9 Bcf/year) based on existing biomass availability, equivalent to approximately 32 percent of total annual fossil natural gas demand in California.[134] The range between these two estimates is similar to the results in studies ICF Consulting (ICF) conducted, which projects 148 Bcf/year (153 million

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130 CPUC California Electric and Gas Utility Cost Report, AB 67 Annual Report to the Governor and Legislature (2020) at 53 https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2019%20AB%2067%20Report.pdf.

131 SoCalGas AL 5745 https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/5745.pdf, and SDG&E AL 2938 http://regarchive.sdge.com/tm2/pdf/2938-G.pdf.

132 CPUC Core Transport Agency Fact Sheet https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/Fact_Sheets/English/CHANGES--Gas%20Aggregation%20for%20CONSUMERS_v001.pdf.

133 CEC "2019 Integrated Energy Policy Report," at 266, citing UC Davis report from Catherine Elder, "Effects on California of Winding Down Natural Gas" (2017), https://www.onlinelibrary.wiley.com/doi/10.1002/gas.22108. https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report.

134 UC Davis "A Research Report from the National Center for Sustainable Transportation" (2019) at 43 https://escholarship.org/content/qt0055g3kb/qt0055g3kb.pdf?t=q16ebg.

MMBtu/year) for its low resource scenario and 596 Bcf/year (618 million MMBtu/year) for the technical scenario.[135] Falling squarely in that range, a 2014 Bioenergy Association of California report estimates the state has the potential to generate about 284 billion cubic feet (Bcf) of biomethane from organic waste alone.[136] The CEC's 2019 Integrated Energy Policy Report (IEPR) noted:

> Injection of RNG—produced from biomass—into the pipeline can lower net system GHG emissions relative to an all-fossil natural gas supply. Multiple sectors are already competing for the limited supply of RNG, including heavy-duty transportation.[112] Synthetic natural gas, which is produced using carbon dioxide and hydrogen from sustainable sources, is another option;[113] production requires a renewable, climate-neutral CO_2 source. Low-cost waste bio-CO_2 is relatively limited; other more expensive sources of climate-neutral CO_2 are needed to produce synthetic natural gas using not-yet-commercial technologies.[114] Clean hydrogen could also be blended with natural gas, within limitations with regard to the amount that could be safely injected into pipelines.[115] All these options should be considered when looking at potential decarbonization of the natural gas system.[137]

"Deep Decarbonization in a High Renewables Future" states that there is an insufficient amount of RNG in California to meet long-term demand for low-carbon fuels in buildings and industries without widespread electrification.[559] It is uncertain how much of a role RNG will play in power generation, but the state should give this issue more attention as part of its long-term planning.[138]

Although current biomethane production in California is going to vehicle fuels rather than gas IOUs' core customers, there is potential for production to expand beyond the volumes needed in the LCFS program in the event the natural gas transportation market becomes saturated with biomethane. As explained below, IOU purchases of biomethane for core customers could reduce methane emissions and move California closer to its SLCP reduction goals.

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[135] American Gas Foundation "Renewable Sources Of Natural Gas: Supply And Emissions Reduction Assessment" (2019) https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.
[136] UC Davis "A Research Report from the National Center for Sustainable Transportation" (2019) at 2 https://escholarship.org/content/qt0055g3kb/qt0055g3kb.pdf?t=q16ebg, citing J. Levin, K. Mitchell, H. Swisher, B. Org, Decarbonizing The Gas Sector: Why California Needs A Renewable Gas Standard About the Bioenergy Association of California, 2014.
[137] 2019 Integrated Energy Policy Report, California Energy Commission at 47-48 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report.
[138] *Id.* at 266.

3.4 Prioritizing Resource Procurement

The various sources of biomethane will all play a different role in helping California meet its climate goals. Significantly increasing biomethane production will require long-term purchase agreements so that project producers can obtain lower cost financing, which will result in lower biomethane production costs. Project producers may be willing to trade high profits from current LCFS and RIN prices for security in longer term deals, despite lower profits from the long-term contracts. For example, UC procures both in-state and out-of-state biomethane for 10–20-year contracts at prices below LCFS markets because many biomethane producers seek the guarantee of long-term contracts.[139]

Dairy biomethane is a feedstock with great potential to reduce GHG emissions. California is the nation's largest milk, butter, ice cream, nonfat dry milk, and whey protein concentrate producer, and its second largest cheese producer. Dairy cows are responsible for 46 percent of California's total methane emissions[140] and emit methane through their burps and manure.[141] The 26 percent of California methane emissions that come from livestock manure are not currently regulated for the purpose of methane emissions abatement. Thus, that manure typically will produce methane that vents directly into the atmosphere. California's large number of dairy cows—1.75 million in 2017—produces a considerable amount of methane emissions—approximately nine percent of the state GHG emissions—even though the number of cows has been decreasing over time.[142] Further, the demand for dairy products has been increasing. In the last decade, per capita consumption of milk has decreased, but cheese has increased 19 percent, butter has increased 24 percent, and yogurt has increased seven percent.[143] If these consumption

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139 UC signs 20-year contract with Anaergia Rialto bioenergy facility https://www.universityofcalifornia.edu/news/how-garbage-landfills-helping-power-uc-s-advance-clean-energy-future.

140 26 percent of California livestock methane emissions are from manure, and 28 percent of methane emissions is from enteric fermentation (released through the mouth and nose). CARB methane inventory (2017). Livestock include dairy cattle, beef cattle, horses, bulls, sheep, goats, swine, and poultry. https://www.arb.ca.gov/cc/inventory/data/graph/treemap/ghg_2000-16.htm.

141 Cows' methane emissions from burps can be reduced 99 percent by introducing two percent of seaweed to their diet, but this is not yet in widespread use for a variety of reasons. Over 95 percent of dairy cattle methane emissions are released from the mouth or nose. Manure emissions occur during anaerobic decay. D. Nelson "Can Seaweed Cut Methane Emissions on Dairy Farms?" (2018) https://www.ucdavis.edu/news/can-seaweed-cut-methane-emissions-dairy-farms/ citing B. M. Roque, J. K. Salwen, R. Kinley, E. Kebreab, "Inclusion of Asparagopsis armata in lactating dairy cows' diet reduces enteric methane emission by over 50 percent," Journal of Cleaner Production, Volume 234, 2019, Pages 132-138, ISSN 0959-6526, https://e-tarjome.com/storage/panel/fileuploads/2019-08-24/1566635509_E12806-e-tarjome.pdf.

142 United States Department of Agriculture (USDA) Economic Research Service Dairy Data "U.S. dairy situation at a glance (monthly and annual)" last updated December, 14, 2020 https://www.nass.usda.gov/Statistics_by_State/California/Publications/County_Estimates/2016/201705LvstkCActy.pdf.

143 USDA Economic Research Service National Agricultural Statistics Service "California Cattle County Estimates" (2020) https://www.ers.usda.gov/webdocs/DataFiles/48685/Dairyglance.xlsx?v=6237. Accessed from: https://www.ers.usda.gov/data-products/dairy-data/.

trends continue, and actions are not implemented to curb dairy cow emissions or increase production efficiency sufficient to offset increased demand, California risks failing to achieve the methane emission reduction target for the sector outlined in SB 1383. This may also inhibit the state's ability to achieve its broader decarbonization and carbon neutrality goals.

Production of dairy biomethane is increasing due to incentives from the LCFS and RFS, as well as additional incentive programs promulgated as part of the state's SLCP reduction efforts. Currently, the LCFS program allows dairies to claim avoided methane emissions when calculating their biomethane carbon intensity. This results in a negative carbon intensity for dairy biomethane, which improves the economics for dairy projects that generate LCFS credits. Additional incentives for dairy biomethane production totaling up to $2 million per project are available from the CDFA.[144] As mentioned previously, the CPUC's monetary incentive program for biomethane projects also provides up to $3 million for individual biomethane production projects and up to $5 million for dairy cluster biomethane production projects.[145]

Data provided as part of the CPUC's approval of six dairy biomethane pilot projects mandated by California Health and Safety Code Section 39730.7(d)(2) indicates that the most expensive of the six projects' capital and operating and maintenance (O&M) costs would break even with a 10-year contract valued at approximately $12.50/MMBtu.[146] Despite this relatively low total cost, it is unlikely that dairy biomethane producers will contract with the gas IOUs for procurement under SB 1440 if they can earn in excess of $50/MMBtu through the LCFS program by selling into the transportation sector.[147]

Landfill biomethane is the biomethane source that generally has the lowest price among biomethane sources because of its higher carbon intensity calculated under the LCFS program. Unlike dairies, most landfills have a lower price in the LCFS program because they are already subject to methane abatement regulation measures. Therefore, landfills are not allowed to claim avoided methane emissions when

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144 CDFA "2019 Dairy Digester Research and Development Program: Grant Application Workshops Presentation" at 4 https://www.cdfa.ca.gov/oefi/ddrdp/docs/2019-DDRDP_ApplicationWorkshopPresentation.pdf.
145 AB 2313 (Williams, 2016).
146 This estimate is calculated from revenue requirements published in ALs from SoCalGas (*see*: SoCalGas AL 5398-A at https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/5398-A.pdf) and PG&E (*see*: PG&E AL 4049-G-A https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4049-G-A.pdf) by taking total costs and 10 years of O&M costs, divided by estimated RNG volume produced per year.
147 In the event that the market for low carbon transportation fuel becomes saturated and there is a risk of surplus production, then there may be opportunities for California's gas IOUs to procure dairy biomethane at a lower price. Market saturation is a possibility if dairy biomethane production continues to ramp up and demand for CNG remains static. However, dairy biomethane production would likely continue even after market saturation due to its ability to displace resources with higher CI currently receiving LCFS funding.

calculating their lifecycle carbon intensity, which results in a higher carbon intensity score relative to other sources like dairy biomethane whose methane emissions are not presently regulated.[148] If the mandatory capture of landfill methane is not used for substitution of fossil natural gas in the natural gas transportation fleet or for electricity generation under California's Renewables Portfolio Standard (RPS), then the methane is generally destroyed through flaring. However, despite existing methane capture mandates, CARB estimates in one study that only 65 percent of landfill methane is captured while the rest ends up venting into the atmosphere.[149] In 2020, the CEC commissioned "The California Methane Report," wherein Jet Propulsion Laboratory (JPL) drones collected data from methane point emissions across California.[150] The study concluded that point source emitters comprise 34-46 percent of California's 2016 methane emissions (according to total values of CARB's 2016 GHG inventory) and that landfills dominate point source emitters (41 percent), followed by dairies (26 percent) and the oil and gas sector (also 26 percent). By contrast, the CARB 2016 study on sources of methane estimates landfill to comprise 22 percent of the state's methane emissions.[151]

The methane emissions resulting from landfills compelled SB 1383's landfill organics waste diversion goals. To meet these goals, action must be taken to increase capacity to use the diverted organic waste. CalRecycle estimates that 2025 capacity will limit landfill organic waste diversion to an additional 10 million tons. In order to meet the 2025 goal established in SB 1383, however, required additional capacity for landfill organic waste diversion is approximately 18 million tons. CalRecycle indicates that the estimated capacity shortfall of eight million tons must be met in large part through increased anaerobic digestion and co-digestion, both of which generate biogas that can be upgraded into biomethane. CalRecycle's estimated capacity for each type of use are reflected in

148 SB 1383 specifies that dairy/livestock regulations shall not be implemented sooner than 1/1/2024 and only if CARB, in conjunction with CDFA, makes certain findings with respect to technological feasibility, economic feasibility, and minimizes leakage to other states/countries.
149 65 percent methane capture efficiency is the average of aerial measurements of 10 landfills measured in CARB and Cal Poly's 2020 report "Estimation and Comparison of Methane, Nitrous Oxide, and Trace Volatile Organic Compound Emissions and Gas Collection System Efficiencies in California Landfills" at 12 https://ww2.arb.ca.gov/sites/default/files/2020-06/CalPoly%20LFG%20Flux%20and%20Collection%20Efficiencies%203-30-2020.pdf.
150 Duren, Riley, Andrew Thorpe, Ian McCubbin. 2020. The California Methane Survey. California Energy Commission. Publication Number: CEC-500-2020-047 https://ww2.energy.ca.gov/2020publications/CEC-500-2020-047/CEC-500-2020-047.pdf.
151 CARB GHG Emissions Inventory: Sources of Methane in California – Total CH_4 Emissions https://ww3.arb.ca.gov/cc/inventory/background/ch4.htm.

Table 3. However, even if the SB 1383 landfill diversion goals are met by 2025, organic waste that is not yet diverted and is deposited in landfills today will continue emitting methane after oxygen is depleted, at a stable rate for 20 years and "continue to be emitted for 50 or more years."[152]

Table 3: Estimated Composting, Anaerobic Digestion, and Chip-and-Grind Capacity in 2025 (Million Tons)[153]

Technology	Estimated Anticipated Capacity, 2025	Estimated Needed Capacity, 2025	Difference
Compost	5.3	9.6	(4.3)
Anaerobic Digestion	1.0	2.7	(1.7)
Co-Digestion	0.21	2.4	(2.2)
Chipping and Grinding	3.5	3.3	0.2
Total	10.0	18.0	(8.0)

The diversion of organic waste from California's landfills will directly impact the operations of the state's wastewater treatment facilities. SWRCB published a 2019 study on wastewater treatment plant ability to anaerobically co-digest wastewater and organic waste at existing facilities.[154] The California Association of Sanitation Agencies (CASA) states that there are currently 153 wastewater treatment facilities in California with digesters already on-site, most of which have excess capacity that could be used to generate biomethane.[155] CASA conservatively estimates that at least 75 percent of food waste currently landfilled could be accepted for co-digestion using largely existing infrastructure at wastewater treatment plants and that a modest volumetric increase of food waste for co-digestion can double the biogas production."[156] CEC estimates that co-digestion can increase biogas production by 58 percent.[157] Major investments are already

[152] Department of Health and Human Services Agency for Toxic Substances and Disease Registry Division of Health Assessment and Consultation, "Landfill Gas Primer: An Overview for Environmental Health Professionals" Chapter 2 (2001) at 5 https://www.atsdr.cdc.gov/HAC/landfill/PDFs/Landfill_2001_ch2mod.pdf, citing Crawford JF and Smith PG. 1985. Landfill technology. London: Butterworths.
[153] CalRecycle "Analysis of the Progress Toward the SB 1383 Organic Waste Reduction Goals" (2020) Table 1 at 7 https://www2.calrecycle.ca.gov/Publications/Download/1589.
[154] SWRCB "Co-Digestion Capacity in California" https://www.waterboards.ca.gov/water_issues/programs/climate/docs/co_digestion/final_co_digestion_capacity_in_california_report_only.pdf.
[155] CASA research shows there are 153 existing in-state wastewater treatment plants with digesters that can be converted to accept organic waste diversion. *See* "2015 Estimate of Excess Capacity at Existing Anaerobic Digesters for Co-Digestion at Wastewater Treatment Facilities in California": https://casaweb.org/wp-content/uploads/2015/12/Summary-of-Estimate-of-Excess-Capacity-for-Co-digestin-in-CA_081718-With...1.pdf.
[156] CASA Comments on Scoping Memo July 26, 2018 at 4 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M221/K852/221852283.PDF.
[157] Rajagopalan, Ganesh; Bhargavi Subramanian, Helia Safaee, and Ryan Holloway. 2020. Lowering Costs of Food Waste Codigestion for Renewable Biogas Production. California Energy Commission. Publication Number: CEC-500-2020-069CEC "Lowering Costs of Food Waste Codigestion for Renewable Biogas Production" at 23 https://ww2.energy.ca.gov/2020publications/CEC-500-2020-069/CEC-500-2020-069.pdf.

being made to upgrade wastewater treatment facilities like the Anaergia partnership with Victor Valley Water Reclamation Authority (retrofit project estimate: $2.6 million) to convert black bin and food waste into digestible slurry, tripling biogas production for the purpose of producing biomethane and electricity generation.[158,] Other examples of wastewater treatment plants modified to accept organic waste include Central Marin Sanitation Agency[159] and the Los Angeles County Sanitation District Carson plant.[160] As of March 2020, there are five operational co-digestion facilities in California.[161]

Additional evidence further indicates that wastewater treatment facilities will play a large role in reducing methane emissions.[162] According to SWRCB, CASA, and the CEC, a modification to existing facilities to pre-process and accept organic waste for co-digestion can promote greater biomethane production efficiency. Co-digestion is also a cost-effective solution for waste disposal companies because tipping fees are cheaper at wastewater treatment plants than at landfills.[163] Tipping fees are disposal fees imposed by landfills, biomass facilities, and composting operations that all vary in price based on the types of waste received. The fees are complex and often not posted, yet tipping fees are generally cheaper at biomass facilities than landfills and composting operations, and more expensive at landfills receiving municipal solid waste.[164] A wastewater treatment facility that accepts organics diverted from landfills could offer lower tipping fees to both encourage organic waste diversion and offset its own costs through a combination of tipping fee proceeds and biomethane sales.

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158 WaterWorld, "Power of Digestion: Water Authority Embarks on Journey to Energy Neutrality with High Solids Thickening Digester" (2014) https://www.waterworld.com/technologies/article/16192860/power-of-digestion-water-authority-embarks-on-journey-to-energy-neutrality-with-high-solids-thickening-digester.
159 *See*: https://www.cmsa.us/assets/documents/administrative/CMSAMethCaptureFeasibilityStudyFinalUPDATED010809.pdf.
160 *See*: https://dpw.lacounty.gov/epd/tf/minutes/tfminATAS2020-11.pdf.
161 *See*: https://www2.calrecycle.ca.gov/Docs/Web/115971.
162 CARB "Short-Lived Climate Pollutant Reduction Strategy" (2017) at 9 https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.
163 CEC "Lowering Costs of Food Waste Codigestion for Renewable Biogas Production" https://ww2.energy.ca.gov/2020publications/CEC-500-2020-069/CEC-500-2020-069.pdf.
164 CalRecycle "Landfill Tipping Fees in California" (2015) at 17 https://ww2.energy.ca.gov/2020publications/CEC-500-2020-069/CEC-500-2020-069.pdf.

Table 4: Summary of Proposed CARB 2017 SLCP Estimated Annual Emission Reductions by 2030

Feedstock Type	Annual MMTCO2e	Annual Flared MMTCO2e165	Annual Millions of MMBtu
Dairy and Other Livestock	26	0.36	6.81
Landfill	4	0.06	1.05
Wastewater, Industrial, and Other Miscellaneous Sources	8	0.11	2.10

Standalone anaerobic digestion facilities that solely process the organic fraction of municipal solid waste are another biomethane procurement option gaining traction in California that can help support CalRecycle's goals.[166] These facilities can process feedstocks ranging from wet pumpable food and liquid wastes to more dry stackable food and green waste. Additionally, there are hybrid systems that can accommodate a mix of wet and dry feedstocks.

Standalone anaerobic digestion facilities typically incorporate preprocessing equipment to separate organic waste from the non-digestible portion of the waste stream, which can include magnetic, fluid and density separation, grinding, pressing, and screening. The organic waste is then anaerobically digested, generating biogas and digestate (as both solid and liquid streams). The biogas primarily contains methane and CO_2, but may contain impurities such as moisture, H_2S, and ammonia. The biogas is cleaned and upgraded prior to being injected into the pipeline, used on-site for electricity production, or used to fuel CNG vehicles. The solid and liquid digestate can be further processed into products such as compost, liquid fertilizer, or other soil amendments.

There are currently nine standalone anaerobic digestion facilities operating in California and eight of those facilities are anticipated to begin operations with new or expanded capacity within the next few years.[167] Examples of standalone anaerobic digesters include the CR&R facility in Perris, Zero Waste Energy

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165 CARB uses a methane 20-year GWP value of 72 in accordance with IPCC Fourth Assessment, therefore the conversion for the flared value of $MMTCO_2e$ uses a different 20-year GWP factor used in this report.
166 SWRCB "Co-Digestion Capacity in California" https://www.waterboards.ca.gov/water_issues/programs/climate/docs/co_digestion/final_co_digestion_capacity_in_california_report_only.pdf.
167 CalRecycle awards grants through the Organics Grant Program. Eight of the standalone facilities as of March 2020 are posted to the CalRecycle documents site. *See*: https://www2.calrecycle.ca.gov/Docs/Web/115971.

facilities in Monterey, San Jose, and South San Francisco, and the HZIU Kompogas facility in San Luis Obispo. CR&R operates a hybrid material type anaerobic digestion system in Perris that can process food and green waste. This facility generates compost from the digestate and biomethane used to fuel CNG vehicles. Zero Waste Energy has constructed anaerobic digestion facilities in Monterey, San Jose, and South San Francisco that digest food and green waste. The resulting biogas is directed to electricity generation or upgraded to fuel waste-hauling CNG vehicles. The digestate is further processed into compost. Finally, HZIU Kompogas operates a dry type anaerobic digester in San Luis Obispo. Food and green waste are fed into the digester, where a higher temperature thermophilic process provides spore and bacterial treatment. The resulting biogas is directed to electricity generation and the digestate is cured and used as compost.

Standalone anaerobic digestion facilities processing municipal solid waste organic feedstocks are also a viable biomethane generation option in addition to landfills, dairies, and wastewater treatment plants, and are a critical part of the infrastructure California needs to meet its SB 1383 goals. These facilities will be a necessary source of biomethane because existing anaerobic digesters at wastewater treatment plants will not be able to absorb all the organic waste diversion required to support CalRecycle's goals. CR&R in Perris and HZIU Kompogas in San Luis Obispo are two examples of large standalone facilities currently in operation.

Another important resource-related consideration is the potential for biomass to be converted to Bio-SNG through non-combustion thermal conversion[168] and help abate GHG emissions. Currently, a portion of biomass such as agricultural waste and forest management byproduct is converted into energy through combustion to generate renewable electricity through two mandated bioenergy programs: the Bioenergy Market Adjusting Tariff (BioMAT)[169] and the Bioenergy Renewable Auction Mechanism (BioRAM).[170] The BioMAT program was created in response to SB 1122 (Rubio, 2012) and provides opportunities for small bioenergy facilities to sell electricity to IOUs in the three discrete categories of municipal biogas, agriculture, and forest which have respective procurement targets.[171] The BioRAM program implemented Governor Brown's 2015 Emergency Order and was expanded by SB 859 (Committee on Budget and Fiscal Review, 2016), ultimately requiring procurement of 146 MW intended to target High

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168 Thermal conversion is the conversion of biomass into energy using combustion, gasification, pyrolysis, and hydrothermal processes. *See* National Renewable Energy Laboratory (NREL) "An Introduction to Biomass Thermal Conversion" https://www.nrel.gov/docs/gen/fy04/36831e.pdf.
169 CPUC's Bioenergy Feed-in Tariff Program. *See*: https://www.cpuc.ca.gov/sb_1122/.
170 CPUC's Bioenergy Renewable Auction Mechanism (BioRAM). *See*: https://www.cpuc.ca.gov/bioram/.
171 Biogas: from wastewater treatment, municipal organic waste diversion, food processing, and co-digestion—110 MW; Dairy and other Agricultural—90 MW; Forest: including fuels from high hazard zones (HHZ)—50 MW. No Forest category BioMAT plants are yet operating.

Hazard Zone (HHZ)[172] biomass feedstock.[173] However, electricity generating facilities using direct biomass combustion are lower in efficiency, significantly more costly, and emit more air pollution than electricity generation using combustion.[174] Those biomass fuel resources could instead be used, under the right circumstances, to produce energy through thermal conversion in the form of Bio-SNG or hydrogen with less localized air pollution than biomass combustion, thus reducing the number of smaller and inefficient combustion generators across the state. For example, the Advanced Biofuels Solutions Ltd (ABSL) Swindon UK wood gasification plant can produce Bio-SNG and hydrogen. A woody biomass Stockton plant has the potential to generate three Bcf of biomethane annually using 310,000 tons of woody biomass.[175]

Lawrence Livermore National Laboratory (LLNL) estimated in their "Getting to Neutral" study that converting California's annual supply of forest biomass (24 million bone-dry tons) into biofuels coupled with CCS could achieve about 70 million tons of GHG mitigation.[176] Further, California and the US Forest Service recently agreed to improve sustainable timber harvest and develop markets for wood products and recycle forest byproducts in order to avoid burning slash piles.[177] A Gas Technology Institute (GTI) study, in collaboration with CARB and the Sacramento Municipal Utilities District, found that producing biomethane or Bio-SNG from agricultural and wood waste and injecting it into a pipeline "virtually eliminates all criteria pollutants associated with existing biomass electricity production facilities."[178] The study further found that converting a biomass electric power plant in Stockton to a biomethane production facility would take about 44 months to complete and produce renewable gas at a cost of $13-$15 per MMBtu, with a relatively low LCFS carbon intensity estimate of 16.8 gCO_2e/MJ (2018).[179] Thus Bio-SNG

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[172] HHZ geographic maps are defined by CalFire. https://gis.data.ca.gov/datasets/e50b7577426c4367a518b80b38e9b5d8_0
[173] The BioRAM program is fully subscribed with the exception of additional existing IOU bioenergy contracts eligible under SB 901 (Dodd, 2018).
[174] Y. Yoshida, K Dowaki, Y.Matsumura, R. Matsuhashi, D. Li, H. Ishitani, H. Komiyama, "Comprehensive comparison of efficiency and CO_2 emissions between biomass energy conversion technologies—position of supercritical water gasification in biomass technologies," Biomass and Bioenergy, Volume 25, Issue 3, 2003 https://www.academia.edu/26054521/Comprehensive_comparison_of_efficiency_and_CO2_emissions_between_biomass_energy_conversion_technologies_position_of_supercritical_water_gasification_in_biomass_technologies.
[175] The woody biomass has 17 percent moisture and full plant capacity is 82 Bcf/year. Gas Technology Institute (GTI) "Low-Carbon Renewable Natural Gas (RNG) from Wood Wastes" (2019) at 7 https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf.
[176] Lawrence Livermore National Laboratory (LLNL) "Getting to Neutral" (August 2020) https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.
[177] "Agreement for Shared Stewardship of California Forest and Rangelands Between the State of California and the United States Department Of Agriculture (USDA), Forest Service, Pacific Southwest Region" Memorandum of Understanding (MOU). *See*: https://www.gov.ca.gov/wp-content/uploads/2020/08/8.12.20-CA-Shared-Stewardship-MOU.pdf.
[178] GTI "Low-Carbon Renewable Natural Gas from Wood Wastes" at 2. *See*: https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf.
[179] *Id.* at 65-69.

or hydrogen derived from non-combustion thermal conversion of woody biomass can be a cost-effective method to support California's goals for reducing black carbon (an SLCP enumerated in SB 1383), reducing wildfire risk, and decreasing wildfire-related GHG emissions.[180]

[180] California ten-year average for wildfire black carbon emissions are 86.7 $MMTCO_2e$ (20-year GWP) and 24.4 $MMTCO_2e$ (100-year GWP). *See*: CARB GHG Inventory https://ww2.arb.ca.gov/ghg-slcp-inventory.

4 Recommendations

California is in the process of transitioning away from the use of fossil natural gas in its energy sector, including in electric generation and buildings. To support this transition, the International Energy Agency (IEA) recommends priority action in "[c]ritical areas such as electrification, hydrogen, bioenergy and carbon capture, utilisation and storage (CCUS)."[181] While there is not yet an explicit requirement to electrify buildings, recent legislation such as SB 1477 (Stern, 2018) and AB 3232 (Friedman, 2018), as well as a multitude of local reach codes,[182] clearly orient California toward a future in which all-electric buildings powered by renewable electricity are the goal. Additionally, the CPUC has already approved several ratepayer-funded incentive programs to accelerate building electrification.[183] However, complete building sector decarbonization may take decades to achieve and even the most aggressive building electrification models envision a role for biomethane and other renewable gas sources in powering operations that are hard to electrify and helping generate flexible electricity that can balance the intermittency of wind and solar generation.[184] As such, it is both prudent and consistent with statutory directives found in PU Code Section 399.24[185] and elsewhere to further encourage biomethane procurement.

Approving a biomethane procurement program for California's gas IOUs conforms with existing state climate policy. Executive Order B-55-18 mandates that California "achieve carbon neutrality as soon as possible, and no later than 2045, and achieve and maintain net negative emissions thereafter."[186] In 2017, CARB released "California's 2017 Climate Change Scoping Plan Update," stating that more than one-third of California's climate strategy depends on the state reducing emissions from SLCPs like methane.[187] Also in 2017, the CEC reported in *Deep Decarbonization in a High Renewables Future* that in "the High Electrification Case, biomethane is used to decarbonize a portion of the natural gas use in buildings and industry, along

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[181] IEA, Paris "Net Zero by 2050. A Roadmap for the Global Energy Sector" May 2021 at 16. *See*: https://www.iea.org/reports/net-zero-by-2050.
[182] A "reach code" is a local building energy code that reaches beyond the state minimum requirements for energy use in building design and construction, creating opportunities for local governments to lead the way on clean air, climate solutions, and the renewable energy economy, while creating roadmaps for other local governments to take action as well. For more information, *see*: https://www.nrdc.org/experts/pierre-delforge/san-joses-proposed-building-reach-code-explained.
[183] For more information, *see*: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442465700.
[184] Mahone, Amber, Zachary Subin, Jenya Kahn-Lang, Douglas Allen, Vivian Li, Gerrit De Moor, Nancy Ryan, Snuller Price. 2018. Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model. California Energy Commission. Publication Number: CEC-500-2018-012 at 3 https://efiling.energy.ca.gov/GetDocument.aspx?tn=223785.
[185] *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=399.24.&lawCode=PUC.
[186] *See*: https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.
[187] CARB "California's 2017 Climate Change Scoping Plan Update: The strategy for achieving California's 2030 greenhouse gas target" (2017) https://ww3.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

with providing renewable CNG for a portion of CNG trucks."[188] Executive Order N-82-20 further calls for California state agencies to support "pathways for sectors such as agriculture and forestry to participate in the transition to a carbon neutrality economy," suggesting a potential for biomass to be converted into biomethane.[189]

A biomethane procurement program would further provide market stability to other biomethane initiatives. Long-term contracts add greater financial certainty for biomethane project producers currently receiving LCFS incentives by providing an alternative market to sell into in the event that the LCFS transportation fuels market becomes saturated. The greater financial certainty would, in turn, increase the bankability of a project and thus speed up construction and interconnection processes.

This "Recommendations" section of the Staff Proposal articulates recommendations for the successful implementation of a biomethane procurement program. First, Staff address how cost-effectiveness should be determined and how the contract approval process should work. Second, Staff recommend targets for a biomethane procurement program in the short- and medium-term. Finally, Staff address what other requirements should be considered that complement the recommended cost-effectiveness framework and procurement targets.

4.1 Cost-effectiveness

Staff recommend that the CPUC require the four large gas IOUs to jointly develop a Standard Biomethane Procurement Methodology (SBPM) for determining the cost-effectiveness of procuring biomethane and submit it for CPUC approval as a Tier 2 AL. Once the SBPM is adopted, biomethane contract prices should prospectively be analyzed by the gas IOUs through the SBPM. The SBPM cost-effectiveness test will be the first step in determining whether the biomethane procured is least-cost with the most GHG reduction benefit. Contracts with prices consistent with the SBPM will then be subject to CPUC approval. If the biomethane contract price is below what the SWRCB determined to be approximate co-digestion pipeline injection project costs ($17.70/MMBtu), then it should be subject to Tier 1 AL approval to ensure efficient procurement. The gas IOUs should be required to file Tier 2 ALs for approval of any

[188] *See*: https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf at 47.
[189] *See*: https://www.gov.ca.gov/wp-content/uploads/2020/10/10.07.2020-EO-N-82-20-.pdf.

contracts above \$17.70/MMBtu, but below the social cost of methane (\$26/MMBtu). If a gas IOU seeks to procure biomethane for a contract priced greater than \$26/MMBtu, then it must submit a Tier 3 AL.

Oregon's gas utility NW Natural adopted a cost-effectiveness test that considers the price of natural gas, costs associated with transporting the gas, the cost of biomethane, cost of emissions compliance, and carbon intensity, among many other factors. A portfolio that includes biomethane is then tested for cost-effectiveness by comparing it to an equivalent portfolio without biomethane to determine the maximum risk-adjusted commodity contract price customers would be willing to pay for the biomethane resource under consideration.[190] This test is a transparent cost-benefit calculation. Staff recommend directing California's gas IOUs to submit a joint, uniform SBPM with inputs, outputs, and transparency that are similar to the NW Natural cost-effectiveness test.

Each biomethane producer will have a custom price per unit requirement, so the SBPM will need to account for each project's price using a cost-effectiveness test to provide a reasonable price catered to each specific biomethane producer. The SBPM cost-effectiveness test will have inputs and outputs that reflect the issues arising from the three perspectives discussed in Section 3.2. Cost-effectiveness analyses from the following three perspectives will be required for biomethane procurement: (1) the biomethane producer, (2) the utility and ratepayer, and (3) society at large. These three perspectives may have competing interests. Thus, requiring all three will help provide a prudent, equitable, and reasonable determination of cost-effectiveness.

The first cost-effectiveness analysis should consider benefits and costs to the biomethane producer. The rationale for using this perspective is to provide a sufficient incentive for the producer to build new infrastructure and bear the risk of operating a biomethane production facility, while providing cost containment so that the ratepayer does not pay for excessive profits. The biomethane producer will have a break-even requirement that is necessary to ensure the program's sustainability and success. The high cost of capital expenditures, operations, and maintenance creates a large barrier to market entry for a biomethane producer. Banks, lenders, and investors are essential in raising sufficient capital for infrastructure construction. Further, an uncertain and volatile LCFS market may not necessarily provide the security investors require before a producer can secure a loan. To reduce the risk to the producer, Staff recommend that procurement prices reflect estimated break-even requirements over the duration of a 10-year minimum

[190] NW Natural 2018 IRP at 414 https://edocs.puc.state.or.us/efdocs/HAA/lc71haa151218.pdf.

contract, thereby providing stable long-term contracts that will help secure loans to begin project development. Additionally, consideration of the biomethane producer's perspective can limit expenditures by ensuring cost containment, similar to a Power Purchase Agreement cost containment framework.[191]

The second cost-effectiveness analysis should consider costs and benefits to the utility. The utilities' costs may include reasonable infrastructure costs that may arise, as well as the price differential between biomethane and fossil methane. From the utilities' perspective, the benefits are reduced fossil methane use that will result in avoided costs from Cap-and-Trade compliance, fossil natural gas procurement, and upstream interstate transmission. The cost differential between biomethane (both fuel and infrastructure costs) and the cost of avoided carbon allowances will determine if biomethane is cost-effective from the utility perspective. Even though the avoided carbon allowance cost may be small compared to the cost of biomethane, it is a variable that may increase over time, and it is a quantifiable benefit to utilities. The utilities must explain how they calculate avoided GHG emissions and translate avoided emissions to carbon allowances. These costs should be compared with the avoided costs of procuring carbon allowances over the lifetime of the contract.

The third and final cost-effectiveness analysis should consider costs to society at large. This analysis will provide additional guidance for ensuring that biomethane procurement is fair and reasonable to society. Non-economic benefits to society can be maximized by prioritizing fuels based on their carbon intensity. The lower the carbon intensity, the greater the SLCP reduction. The associated benefits of a fuel should be factored into the cost-effectiveness test using the three environmental benefits enumerated in SB 1440: (1) reduction or avoidance of the emission of any criteria air pollutant, toxic air contaminant, or greenhouse gas in California; (2) reduction or avoidance of pollutants that could have an adverse impact on waters of the state; and (3) alleviation of a local nuisance within California that is associated with the emission of odors.

The gas IOUs' joint and uniform SBPM cost-effectiveness test should consist of inputs and outputs from the three perspectives. Once a biomethane contract price has undergone the SBPM cost-effectiveness test, the gas IOUs should be required to seek CPUC approval through ALs. The AL approval process will give the CPUC an opportunity to review each biomethane procurement agreement to ensure that it is consistent with the SBPM and other related considerations.

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[191] *See* CPUC Staff Proposal for A Methodology to Implement Procurement Expenditure Limitations for the Renewables Portfolio Standard Program: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K235/88235407.PDF.

The threshold for approval of a biomethane procurement contract to be approved by a Tier 1 AL should be cost-effective contracts priced at $17.70/MMBtu or below. A SWRCB study found that co-digestion pipeline injection biomethane project costs are approximately $17.70/MMBtu.[192] The SWRCB price finding is further supported by the findings in an ICF study that estimate that "the majority of the renewable natural gas produced in the high resource potential scenario is available in the range of $7-$20/MMBtu."[193] A 2015 UC Davis study estimated that the price support required to incentivize production over the $3/MMBtu fossil natural gas market price ranged from $11.50 for municipal solid waste to $26 for dairies.[194] Generally, existing biomethane procurement contracts are confidential. However, it is public information that the City of Anaheim's contract with the Rialto BioEnergy Facility[195] is for $12.74/MMBtu, increasing 1.4 percent each year for 20 years.[196] Given the preponderance of evidence supporting SWRCB's numbers, Staff believe that $17.70/MMBtu is an appropriate price threshold for Tier 1 AL approval. The gas IOUs should, however, be allowed to request approval of contracts above the $17.70/MMBtu limit by using a higher tier AL.

The threshold for approval of a biomethane procurement contract to be approved by a Tier 2 AL should be cost-effective contracts priced between $17.70/MMBtu and $26/MMBtu. The higher figure, $26/MMBtu, represents the social cost of methane and may change based on IWG review of the interim values released under the Biden administration.[197] Thus, this price may change with future updates from the federal government. "Social cost" in this context is consistent with the definition provided in California Health and Safety Code Section 38506: "an estimate of the economic damages, including, but not limited to, changes in net agricultural productivity; impacts to public health; climate adaptation impacts, such as

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192 SWRCB "Co-Digestion Capacity in California" at 64. $17.70/MMBtu is calculated by converting $17100/scfm: removing the time factor (minute) and using the conversion factors 1000 cf/Mcf and 1.037 MMBtu/Mcf. The time factor (per minute) is removed because natural gas is purchased by volume, not by flow rate. https://www.waterboards.ca.gov/water_issues/programs/climate/docs/co_digestion/final_co_digestion_capacity_in_california_report_only.pdf.

193 ICF, for the American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," December 2019 at 63 https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

194 The study also states "Biomethane production is assumed to be 2.16 mmBTU/wet ton of waste." UC Davis "The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute" Table 1. *See* https://www.arb.ca.gov/research/apr/past/13-307.pdf.

195 This facility is for processing organic waste.

196 City of Anaheim Contract with SoCal Biomethane LLC at 25 https://www.anaheim.net/DocumentCenter/View/18868/Item-7.

197 Executive Order 13990 of January 20, 2021. https://www.federalregister.gov/executive-order/13990. Section 5(b) established an Interagency Working Group on the Social Cost of Greenhouse Gases (the "Working Group").

property damages from increased flood risk; and changes in energy system costs, per metric ton of greenhouse gas emission per year."[198]

In D.19-08-020,[199] the CPUC adopted the IWG's $21/MSCF ($21.25/MMBtu) value for the social cost of methane for use in the gas IOUs' Natural Gas Leak Abatement Program compliance plans. This $21/MSCF value uses the three percent discount rate based on the IWG 2009 publication. However, in February 2021, the Interagency Working Group (IWG) released interim values for the social cost of methane in response to US Executive Order 13990.[200] Thus, Staff recommend taking the preliminary step of using the three percent discount rate of the IWG interim social cost of methane until the comprehensive values are published in January 2021. This value reflects the social cost of methane for the purposes of a biomethane procurement program. A gas IOU should be able to request approval of biomethane procurement contracts priced above $26/MMBtu only under extraordinary circumstances and using a Tier 3 AL.

The standard of review for each of the ALs is whether the cost for the biomethane is consistent with the cost-effectiveness test in the SBPM. For the Tier 1 AL standard of review, there will likely be minimal review necessary to confirm cost-effectiveness in alignment with the SBPM. For the Tier 2 AL standard of review, there will be a need for added analysis of non-economic benefits. The Tier 3 standard of review will require a holistic approach, evaluating all inputs, outputs, and additional non-economic benefits to determine whether the biomethane procurement is reasonable.

4.2 Targets

Staff recommend that the CPUC adopt short and medium-term targets for the gas IOUs to meet in working toward the long-term goals established as part of an approved biomethane procurement program. Targets should focus on supporting SB 1383's SLCP reductions such that California successfully meets its 2030 goal of a 40 percent reduction in methane emissions below 2013 levels. Special attention should be given to helping California meet or exceed its 2025 landfill diversion goal in order to minimize the amount

[198] *See*: http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=38506.&lawCode=HSC.
[199] *See*: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M311/K449/311449621.PDF.
[200] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990." *See*: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

of new organic material deposited into landfills and instead use that diverted waste to produce biomethane. While neither the CPUC nor participating gas IOUs can compel California municipalities or waste management companies to cooperate in meeting the recommended targets, regulatorily-mandated landfill diversion coupled with the ability to sell biomethane produced from diverted waste to the gas IOUs should be sufficient to elicit the necessary partnership between all stakeholders.

Short-term targets[201] should be based on CalRecycle's needs. To meet the 2025 landfill diversion goals established by SB 1383, CalRecycle estimates that capacity for anaerobic digestion must increase by 1.7 million tons and that capacity for co-digestion must increase by 2.2 million tons. The gas IOUs should immediately work to mitigate the combined 3.9-million-ton capacity shortfall specific to those two sources of biomethane. In light of CalRecycle's additional estimated 4.3-million-ton capacity shortfall for composting and the limited prospects for significant compost expansion, the gas IOUs are presented with an opportunity to accommodate that waste stream by raising their 2025 mitigation target to a minimum of eight million tons.[202]

Recommended short-term targets should be met by encouraging the anaerobic digestion of diverted landfill waste at both standalone digesters and California's wastewater treatment facilities and standalone anaerobic digesters. The SWRCB estimates that California's wastewater treatment plants with anaerobic digesters already on-site can currently accept two million to 7.2 million tons of food waste diverted from landfills.[203] In order to minimize costs, the gas IOUs should seek to execute contracts that utilize this existing excess capacity before pursuing opportunities involving the construction of new standalone digesters. The SWRCB study also shows that maximizing co-digestion capacity could reduce statewide GHG emissions by as much as 2.4 $MMTCO_2e$ per year, more than half of the four $MMTCO_2e$ emissions from landfills that California committed to reducing by 2030. In order to maximize savings to ratepayers, all IOUs should do what SWG proposed to do in AL 1148-G by requesting an exemption from assessing upstream transmission charges on local biomethane procurement.[204]

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201 Understood in this context to mean 2025 targets.

202 Based on SWRCB's study of one facility, the extrapolated estimate of biomethane production for eight million tons of co-digestion is 33.8 million MMBtu, or 32.6 Bcf. This estimate is likely to be an inaccurate calculation, however, because co-digestion facilities drastically differ in efficiency depending on size of the facility and infrastructure upgrades.

203 SWRCB "Co-Digestion Capacity in California" at 45 https://www.waterboards.ca.gov/water_issues/programs/climate/docs/co_digestion/final_co_digestion_capacity_in_california_report_only.pdf.

204 *See* Southwest Gas Advice Letter 1148-G: https://www.swgas.com/en/california-advice-letters.

In 2025, the CPUC should revisit targets by reviewing progress of biomethane procurement and performing supply-demand analysis of technically and economically available feedstock in the state. Biomethane feedstocks are limited resources, thus biomethane procurement must be implemented strategically to promote California's decarbonization efforts. Preliminary medium-term 2030 targets should be based on complementing CARB's SLCP Reduction Strategy in a flexible manner.[205] Because of the high price commanded for dairy biomethane as a result of generous LCFS incentives for ultra-low or negative carbon intensity resources, there will likely be limited opportunities for the gas IOUs to procure dairy biomethane for their core customers unless the LCFS market becomes saturated, other policies direct dairy biomethane to other sectors, and dairy biomethane producers seek to enter into contracts with the gas IOUs valued much lower than what they command in the LCFS market currently. While wastewater co-digestion biomethane using organic materials diverted from landfills should continue to be prioritized by the gas IOUs even beyond the short-term, other sources of biomethane can and should be explored beyond 2025. If landfill gas is procured, Staff recommend that gas IOUs require landfill operators to use technology to improve landfill gas capture[206] and optimize operations using systems such as LOCI Controls.[207]

CARB indicates that four $MMTCO_2e$ must be reduced from landfills annually in order to meet 2030 goals.[208] That value translates to procuring an annual total of 75.5 million MMBtu (72.8 Bcf) by 2030.[209] Staff acknowledge that the 2030 landfill emissions reduction goal is not a direct relationship to biomethane procurement, however Staff believe that this will set a target to the maximum amount of organic waste to divert from landfills. As such, the gas IOUs should aim to procure a minimum of 75.5 million MMBtu (72.8 Bcf) of biomethane annually by 2030, excluding dairy biomethane unless it is procured for LCFS core procurement, and adjusting as necessary according to cost and feedstock considerations.

A biomethane procurement program should maximize benefits for the communities in which biomethane is produced. Not all biomethane production facilities are necessarily equal in terms of their local

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205 CARB "Short-Lived Climate Pollutant Reduction Strategy" (2017) https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

206 If LCFS program rules are modified to better account for the carbon intensity of methane from landfills that escapes without being flared, it will make landfill operators who have invested in these kinds of upgrades more desirable candidates for biomethane procurement.

207 *See*: https://www.locicontrols.com/.

208 CARB "Short-Lived Climate Pollutant Reduction Strategy" (2017) at 63 https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

209 D.19-08-020: "The conversion factor is 55.835 MSCF per metric ton CH_4 [methane] at standard conditions of 1 atmosphere and 60 degrees Fahrenheit." This conversion factor is based on IPCC's AR4 Assessment. However, assuming all landfill gas is captured and flared, then the CO_2 equivalent conversion factor is 18.2 Mcf per metric ton CO_2 because CO_2 has a lower GWP than CH_4. The conversion factor is 1.037 MMBtu per Mcf. *See*: https://www.eia.gov/tools/faqs/faq.php?id=45&t=8.

impacts. For example, two wastewater treatment plants might have the same production capacity, but one might be located much closer to residences and/or businesses than the other. Under these circumstances, the wastewater treatment plant farther from urban development might be a better choice for biomethane procurement, as trucking organic waste could increase local trucking-related emissions. Likewise, the landfills that are currently flaring captured biogas could be more or less likely to expose a community to criteria air pollutants depending local air district rules and proximity to local communities. Procurement should take into consideration the ways in which modifications to a wastewater treatment plant or landfill to increase biomethane production would contribute to or detract from economic, health, and non-energy benefits for local communities. The same basic principle applies to sources of Bio-SNG. Simply put, GHG emissions reductions should not be the sole consideration when procuring biomethane.

4.3 Other Considerations

Staff recommend adopting 10 additional biomethane procurement program requirements to ensure safety, minimize costs to ratepayers, prevent increases in localized particulate emissions, maximize GHG emissions reductions, and facilitate the use of pyrolysis in biomethane production operations. Ensuring safety is especially important, as any failure to appropriately mitigate the toxicity of gas or that gas's potential negative impact on pipeline integrity could result in catastrophic consequences that must be avoided. In addition to safety, Staff believe that the 10 recommended additional program requirements will help prevent unreasonable bill increases, further environmental justice, and help ensure that California meets its climate goals in a timely manner. The 10 recommended additional program requirements are articulated below.

First, Staff recommend adopting an interim permissible amount of CO in biomethane of 0.03 percent, in accordance with Battelle Columbus Laboratories research.[210] This CO standard should remain in place until new legislation authorizes OEHHA and CARB to assess CO and other potential chemicals associated with Bio-SNG production. CO is a dangerous chemical that is not one of the constituents of concern adopted as part of D.14-01-034 because the AB 1900 assessment process applies solely to biogas and excludes Bio-SNG. However, Bio-SNG, due to its production method, is much more likely to contain CO than biogas, and pyrolysis gas sourced from torrefied wood (*e.g.,* burnt forest waste) has a CO level exceeding 30 percent.[211] If Bio-SNG is to be an eligible source of biomethane, it is essential that an interim

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[210] *See*: https://www.osti.gov/biblio/6698176-internal-stress-corrosion-cracking-aqueous-solutions-co-co-sub.
[211] *See*: https://www.sciencedirect.com/topics/engineering/pyrolysis-gas.

standard be adopted and that OEHHA and CARB be able to prospectively assess its potential impacts to human health.[212] Because of California's limited experience with pipeline-injected Bio-SNG, Staff recommend authorizing an appropriate IOU to contract for a study of constituents found in various sources of Bio-SNG outside of California so that OEHHA and CARB have a robust data set from which to analyze and make recommendations.[213]

Second, Staff recommend prohibiting the gas IOUs from procuring biomethane from any production facility that does not limit H_2S before it enters a gathering line. H_2S is a toxic chemical compound that occurs in high concentrations in all sources of biogas. There is a risk that concentrations of H_2S that are harmful to human health could be transported near biogas facilities. R.17-06-015 evaluated the risk of H_2S in gathering lines and declined to require H_2S conditioning before gas enters the gathering lines.[214] However, even though the biogas is eventually conditioned to reduce H_2S to pipeline quality standards,[215] Staff is concerned that H_2S can escape from gathering lines between the digester and the conditioning equipment at concentrations exceeding Occupational Safety and Health Administration (OSHA) limits. If the gathering lines are punctured or leak, the H_2S concentration could be at lethal limits and expose unsuspecting people to grave risk.[216] In the interest of safety, the CPUC should establish procurement eligibility criteria to include H_2S reduction to 10 ppm upstream of the gathering lines to match OSHA allowable work limits and industry standards.[217] This requirement currently is required for CDFA Dairy Digester Research and Development Program (DDRDP) projects[218] and should apply to all biomethane production facilities unless they are already interconnected to an IOU-operated gas pipeline.

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212 The gas IOUs previously proposed an interim CO standard and the CPUC rejected it in D.20-08-035. Staff believe that it is reasonable to reconsider the gas IOUs' request in light of the passage of AB 3163.

213 Similarly, Staff recommend authorizing a study for any additional constituents of concern needing further scrutiny that might be identified by OEHHA and CARB in their next biomethane standards update made pursuant to the AB 1900 process.

214 D.17-12-004 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352373.PDF.

215 The CPUC requires gas entering an IOU-operated pipeline to meet a 4-ppm limit for H_2S. *See*: PG&E Gas Rule 21 and SoCalGas Rule 30.

216 It should be noted that new residential developments are often built atop pipelines carrying dangerous gases of different varieties. In 2014, a well-publicized leak in the City of Arvin necessitated significant remediation efforts and the evacuation of three dozen people from their homes for more than eight months. AB 1420 (Salas, 2015) was adopted in response. *See*: https://www.bakersfield.com/news/pipeline-operator-fined-over-arvin-gas-leak/article_91c29fcc-2da9-5be3-9239-822ced6a0c26.html.

217 OSHA construction and shipyard 8-hour limit for H_2S is 10 ppm. *See*: https://www.osha.gov/hydrogen-sulfide/hazards.

218 The H_2S requirements for CDFA DDRDP projects are required under Authority to Construct (ATC) permits issued by the San Joaquin Valley Air Pollution Control District (SJVAPCD), which refers to District Rules 2201 and 4801 listed here: https://www.valleyair.org/rules/1ruleslist.htm.

Third, Staff recommend requiring that each gas IOU submit a Biomethane Procurement Plan (BPP) that contains estimated annual biomethane procurement levels, ratepayer bill impacts, and any incremental capital infrastructure and/or operations and maintenance costs associated with those procurement levels through the end of 2030. BPPs should be submitted as Tier 3 ALs so that the CPUC can review and, if necessary, refine procurement amount and associated ratepayer bill impacts to acceptable levels. After approval of a gas IOU's BPP, Staff should scrutinize individual procurement contracts to ensure that they conform with the BPP of the gas IOU seeking contract approval. Minor deviations from an approved BPP should be permissible with appropriate rationale. Since each gas IOU's Core Procurement Group procures gas solely for a gas IOU's core customers, Staff assume that the cost of biomethane procurement will affect core customers only. If there is a method within existing rules and regulations in which the gas IOUs can attribute a portion of their biomethane procurement costs to noncore customers, the burden is on the gas IOUs to provide proof and rationale for charging those noncore customers a higher rate. The gas IOUs should be required to file annual reports on March 1 of each year, starting in 2022, detailing *actual* biomethane procurement levels, ratepayer bill impacts, and incremental capital infrastructure and/or operations and maintenance costs for the prior year compared to the *estimated* levels that were approved in their respective BPPs.

Fourth, Staff recommend requiring contingencies in biomethane procurement contracts to account for increases in tipping fees. The gas IOUs should have the right to renegotiate procurement pricing if a landfill operator or a wastewater treatment facility receiving organic waste increases its tipping fees because it is a revenue source for landfills that can provide a windfall when the biomethane production rate and revenue remain the same. The amount of revenue received in tipping fees directly impacts the amount of revenue that the production facility will need from a procurement contract. A facility operator's revenue needs may legitimately have to adjust based on changing conditions, and increased tipping fees may be necessary to maintain biomethane production in many cases. However, if procurement pricing is based on prevailing tipping fees, that should remain the case as conditions change unless a facility operator can demonstrate that an increased tipping fee is necessary to maintain biomethane production.

Fifth, Staff recommend prohibiting the gas IOUs from procuring biomethane from any production facility that does not commit to the exclusive use of low carbon fuel vehicles as part of any expanded operations. Staff is particularly concerned that an increased reliance on trucking of organic waste to digesters could lead to increases in particulate emissions if the trucks used in those operations run on diesel. To help mitigate this problem, Staff recommend that all newly purchased or leased trucks associated with biomethane production facilities exclusively use Bio-CNG, electricity, or hydrogen to cleanly fuel their operations.[219] This approach is consistent with recently-enacted Rule 2305 of the South Coast Air Quality Management District, which "requires warehouses greater than 100,000 square feet to directly reduce nitrogen oxide (NOx) and diesel particulate matter (PM) emissions, or to otherwise facilitate emission and exposure reductions of these pollutants in nearby communities."[220] The warehouse rule includes "acquiring and using natural gas, Near-Zero Emissions and/or Zero-Emissions on-road trucks, zero-emission cargo handling equipment," and more to achieve NOx and particulate matter emissions reduction.

Sixth, Staff recommend that the gas IOUs prioritize procurement of biomethane from production facilities that agree to not increase on-site generation of electricity using its own biogas beyond current generation levels unless that biogas is upgraded to biomethane that generates electricity through an on-site fuel cell stack. This arrangement would require a production facility to disclose current annual on-site generation levels and commit contractually to not exceed those levels prospectively. Combustion of biogas results in particulate emissions that can harm communities in the vicinity of the production facility responsible for the combustion, as discussed in Section 3.1.[221] By incentivizing increased biogas production at existing digesters, Staff do not want to also contribute to increased localized particulate emissions. To avoid harm to local communities, current on-site generation levels should remain the same or decrease unless that on-site generation is produced from non-combustion technology that does not rely on raw biogas. In addition to a focus on reducing particulate emissions, contract prioritization should also extend to producers who commit to capturing and storing the CO_2 that is vented in the biogas production process.

Seventh, Staff recommend that the gas IOUs prioritize procuring biomethane from producers that use CCS because California's geography is well-suited for CO_2 storage.[222] While this approach may restrict participating IOUs from maximizing the amount of biomethane in their respective pipeline systems, it will

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219 To the extent that such trucks end up utilizing Bio-CNG, CPUC should consider authorizing the gas IOUs to expand the arrangements originally put in place in 2018 to incentivize Bio-CNG at IOU-operated pumping stations. This, in turn, could create a larger Bio-CNG market, delay any possible LCFS saturation, and contribute to further decreases in harmful GHG and particulate emissions. This approach is consistent with research funding proposed for approval as part of Resolution G-3573.

220 *See*: http://www.aqmd.gov/docs/default-source/news-archive/2021/board-adopts-waisr-may7-2021.pdf.

221 "The increased mutagenicity measured during some biogas combustion tests identifies a potential issue." Chemical studies also showed that biogas combustion resulted in acidic gases, particularly those containing oxidized sulfur species. These sulfur compounds may be incompletely oxidized. Kleeman, Michael J., Thomas M. Young, Peter G. Green, Stefan Wuertz, Ruihong Zhang, Bryan Jenkins, Norman Y. Kado, and Christopher F.A. Vogel. 2020. Air Quality Implications of Using Biogas to Replace Natural Gas in California. California Energy Commission. Publication Number: CEC-500-2020-034 at 128 https://ww2.energy.ca.gov/2020publications/CEC-500-2020-034/CEC-500-2020-034.pdf at 3.

222 U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. "National Assessment of Geologic Carbon Dioxide Storage Resources—Results: Circular 1386, Ver. 1.1. September 2013. Accessed October 15, 2020. https://pubs.usgs.gov/fs/2013/3020/

nevertheless result in the greatest possible reduction in methane and CO_2 and thus is a more effective way to mitigate GHG emissions. Biogas is comprised of approximately 50 percent CO_2 and 50 percent CH_4, depending on feedstock. Currently, the CO_2 portion of the biogas is vented to the atmosphere, even though it is already captured and separated in a relatively pure stream.[223] As of 2019, CARB's LCFS program authorized CCS projects to generate LCFS credits.[224] A federal carbon sequestration tax credit creates an additional incentive for biomethane production facilities to participate in CCS.[225]

Eighth, Staff recommend requiring CTAs to meet or exceed the level of biomethane procured by the gas IOU that they are competing with in their customer offerings. To eliminate any regulatory ambiguity, a new law should be passed for CTAs mirroring what was already done by AB 380 (Núñez, 2005) for Community Choice Aggregators (CCAs) providing unbundled electricity.[226] Failure to hold CTAs to the same procurement standards as the gas IOUs will undermine the success of a biomethane procurement program by increasing the likelihood that customers leave bundled gas service in order to take advantage of a cheaper fossil natural gas alternative that does not provide the environmental benefits of biomethane. To prevent this from happening, CTAs should have to procure biomethane at or beyond the level specified in a gas IOU's approved BPP for any given year—and submit verification that their customer offerings do indeed contain the requisite amount of biomethane—in order to continue serving unbundled gas customers in a given service territory.

Ninth, Staff recommend that the gas IOUs prioritize procurement of biomethane from production facilities that agree to convert their waste byproduct into soil amendment.[227] Digestate is a byproduct of anaerobic digestion that can be used as organic fertilizer and reduce the need for the chemical fertilizers that commonly pollute soil and water with synthetic and/or petroleum-based nitrate runoff.[228] Biochar is another potential byproduct of biomethane production that can sequester carbon in the long-term while providing

223 Qie Sun, Hailong Li, Jinying Yan, Longcheng Liu, Zhixin Yu, and Xinhai Yu. Selection of appropriate biogas upgrading technology-a review of biogas cleaning, upgrading and utilisation. *See*: http://www.sciencedirect.com/science/article/pii/S1364032115006012.

224 California Air Resources Board. Low carbon fuel standard amendments. *See*: https://ww2.arb.ca.gov/rulemaking/2019/lcfs2019.

225 Federal tax credit 45Q for Class Six wells. *See*: https://www.irs.gov/pub/irs-prior/f8933--2020.pdf.

226 AB 380 enacted PU Code Section 380(e), which specifies that CCAs must procure renewable electricity at the same level as their IOU competitors.

227 This recommendation does not pertain to landfill biomethane, as landfill biomethane is not processed in a way that produces waste byproduct.

228 Shimahata, A.; Farghali, M.; Fujii, M. Factors Influencing the Willingness of Dairy Farmers to Adopt Biogas Plants: A Case Study in Hokkaido, Japan. *Sustainability*. 2020, 12, 7809 https://www.mdpi.com/2071-1050/12/18/7809.

nutrients to soil, although the amount of carbon sequestered can vary by feedstock.[229] Biochar has benefits exceeding compost in that it does not emit methane, is easier to transport because it has no moisture content, and the pyrolysis process that produces biochar destroys dangerous per- and polyfluoroalkyl substances (PFAS), more commonly known as "forever chemicals."[230] Sale of biochar could also help farmers in California and beyond protect the environment, absorb carbon dioxide by increasing soil surface area, and increase crop yields while also providing an additional income stream for biomethane producers.

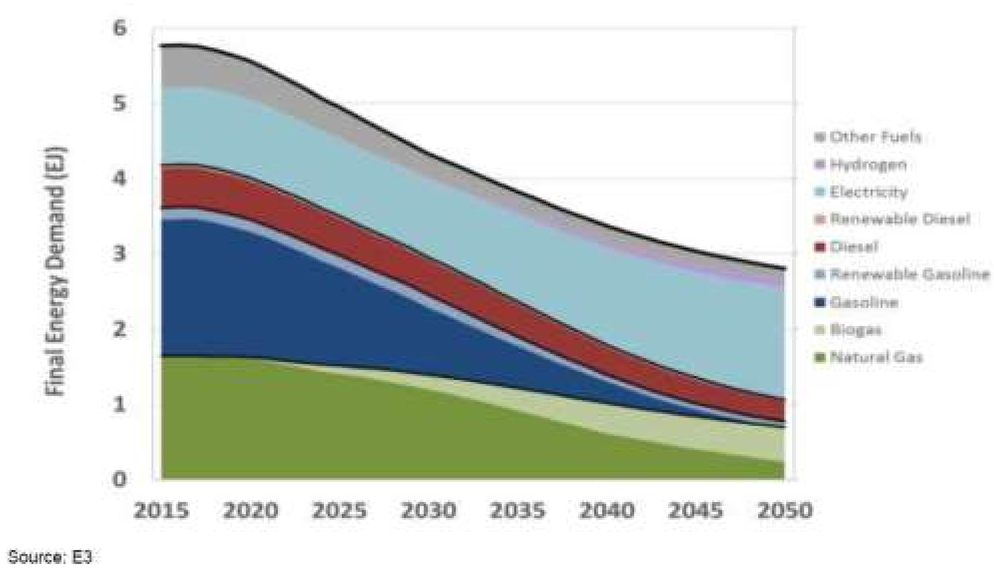
Finally, Staff recommend that California's two largest gas IOUs—PG&E and SoCalGas—each submit an application to the CPUC no later than the end of 2022 for one pilot pyrolysis project that can convert forest waste into biomethane. The Shared Stewardship of California's Forest and Rangelands agreement[231] signed by Governor Gavin Newsom in August of 2020 puts California on track to annually clear one million acres of vegetation that fuels fires by 2025. Much of the biomass resulting from forest clearing will have nowhere to go unless a plan is in place to convert that biomass into pyrolysis gas. The pilot pyrolysis projects should be strategically located in concert with the efforts of both state and local stakeholders in order to process maximal amounts of forest waste, as well as any available farm waste in each project's vicinity. Project costs should include any necessary pipeline extensions needed to transport the biomethane produced from the pyrolysis gas into each IOU's wider pipeline system, and any pipeline extensions should ideally facilitate future potential extensions to additional pyrolysis projects. In addition to utilizing the methane produced by these projects, PG&E and SoCalGas should propose a method by which to utilize the hydrogen and CO_2 produced as a result of pyrolysis rather than venting those gases into the atmosphere.

[229] "Johannes Lehmann, a professor of agricultural science at Cornell University and one of the world's top experts on biochar, has calculated that if biochar were added to 10 percent of global cropland, the effect would be to sequester 29 billion tons of CO_2 equivalent — roughly equal to humanity's annual greenhouse gas emissions." Yale Environment 360, January 2014 https://e360.yale.edu/features/as_uses_of_biochar_expand_climate_benefits_still_uncertain.
[230] EPA Research Brief on Potential PFAS Destruction Technology: Pyrolysis and Gasification https://www.epa.gov/chemical-research/research-brief-potential-pfas-destruction-technology-pyrolysis-and-gasification.
[231] *See:* https://www.gov.ca.gov/wp-content/uploads/2020/08/8.12.20-CA-Shared-Stewardship-MOU.pdf.

5 Conclusion

Biomethane is poised to play an important role in decarbonizing California's economy in the years ahead. Although California has recently achieved impressive reductions in the GHG emissions associated with the electric generation sector, achieving reductions in other sectors' emissions remains challenging.[232] Rather than rely overwhelmingly on the success of the electric generation sector, California must find ways to further decarbonize all industry sectors by using the full range of tools available in its policy toolbox. A CEC study conducted by E3 shows that in a high building electrification scenario biomethane will comprise approximately half of California's gas demand by 2050 (see Figure 1). A recent Energy Futures Initiative (EFI) report concurs: "Clean fuels (*e.g.,* renewable natural gas, hydrogen, biofuels) are critical clean energy pathways due to the enormous value of fuels in providing flexibility for energy systems."[233] It adds, "Policymakers will have to manage the significant operational issues that arise from a high penetration of variable renewable electricity to ensure reliability, manage costs, and minimize emissions."[234]

Figure 1: CEC Deep Decarbonization in a High Renewables Future (High Electrification Scenario)[235]



[232] CARB 2019 Edition, California Greenhouse Gas Emission Inventory: 2000 – 2017
[233] *See*: https://energyfuturesinitiative.org/s/GRD-EFI-Part-2-2.pdf at 16.
[234] *Id.*
[235] Mahone, Amber, Zachary Subin, Jenya Kahn-Lang, Douglas Allen, Vivian Li, Gerrit De Moor, Nancy Ryan, Snuller Price. 2018. Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model. California Energy Commission. Publication Number: CEC-500-2018-012 at 31 https://www.ethree.com/pathways-deep-decarbonization-study/.

Casting California's energy future as a choice between building electrification and biomethane procurement is a false dichotomy. Both an advanced rate of building electrification and increased biomethane procurement are necessary to meet California's goal of net zero carbon emissions. While building electrification will be an essential tool in reducing gas usage and the GHG emissions associated with gas combustion, it offers no solution for mitigating the methane emissions from California's waste streams that are entering the atmosphere with only limited abatement. CARB's SLCP Reduction Strategy notes that a significant amount of GHG emissions come from waste streams and an optimal way to reduce emissions from waste streams is to capture them.[236] Those captured emissions, in the form of biomethane or Bio-SNG, become a pipeline injectable gas interchangeable with fossil natural gas.

This Staff Proposal marks a substantial and important next step toward decarbonizing waste streams, an overlooked and underestimated source of carbon emissions and fuel that will be an essential component in helping California meet its climate goals moving forward. Staff's recommendations would dramatically increase biomethane procurement in a strategic manner that is consistent with the requirements of SB 1440 and complements the SB 1383 SLCP reduction efforts already underway both at the CPUC and other state agencies. In so doing, the recommendations open up the opportunity for longer term contracts, price stability, and backstop procurement in the event that biomethane producers need another market to sell into other than just LCFS. Greater scale of biomethane production could further assist in bringing down the cost of biomethane in the years ahead in a manner comparable to what has been seen with renewable electricity generated by wind turbines and solar panels.[237] Gas customer bills will gradually rise should Staff's recommendations be adopted, but ratepayers will ultimately reap benefits in the form of a cleaner, healthier, and more sustainable California.

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[236] CARB "Short-Lived Climate Pollutant Reduction Strategy" (2017) https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

[237] An International Energy Agency (IEA) study estimates that by 2040 "the average cost of producing biomethane globally is set to be around 25% lower than today, at around USD 14/[MMBtu]." IEA "Outlook for Biogas and Biomethane: Prospects for Organic Growth" (March 2020). *See*: https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/sustainable-supply-potential-and-costs.

END ATTACHMENT