COM/CR6/jnf **Date of Issuance 2/25/2022**

Decision 22-02-025 February 24, 2022

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

DECISION IMPLEMENTING SENATE BILL 1440 BIOMETHANE PROCUREMENT PROGRAM

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DECISION IMPLEMENTING SENATE BILL 1440 BIOMETHANE PROCUREMENT PROGRAM

Summary

We implement Senate Bill 1440 by setting biomethane (i.e., renewable natural gas and/or bio-synthetic natural gas[1]) procurement targets to reduce short-lived climate pollutant emissions. We establish a cost-effective means of procurement and adopt provisions to achieve additional co-benefits, as well as timetables for each investor-owned utility providing gas service in California to achieve specified procurement targets. We adopt related measures to ensure that all actions taken pursuant to this decision are consistent with applicable state and federal laws.

1. Procedural History

On November 21, 2019, the California Public Utilities Commission (CPUC or Commission) initiated Phase 4 of Rulemaking (R.) 13-02-008 to implement Senate Bill (SB) 1440 (Hueso, 2018), which requires the CPUC to consider adopting biomethane procurement targets or goals for each investor-owned utility (IOU) providing gas service in California.[2]

The Phase 4 Scoping Memo outlined three specific action items necessary to implement SB 1440: (1) consultation with the California Air Resources Board (CARB), (2) a determination as to whether biomethane procurement targets or

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[1] Bio-SNG derives from noncombustion thermal conversion, such as pyrolysis and gasification, of exclusively organic material. The feedstocks generally consist of woody biomass, such as forest waste, agricultural waste, and urban wood waste. Bio-SNG is defined in the R.13-02--008 Phase 4A Staff Proposal as follows: "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."

[2] Phase 4 also includes consideration of various hydrogen-related issues, which were either addressed in Application (A.) 20-11-004 or will be addressed later in this proceeding.

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 Code (Pub. Util. Code) Section 651 (b).[3] A subsequent amendment to the Phase 4 Scoping Memo issued June 5, 2020, added seven additional issues (*see* Section 2 below).

On June 3, 2021, the assigned Administrative Law Judge (ALJ) issued a ruling (Biomethane Procurement Ruling) directing parties to comment on an Energy Division staff proposal (Staff Proposal) recommending establishment of a biomethane procurement program for California's four large gas IOUs, a copy of which was attached to the Biomethane Procurement Ruling. The Biomethane Procurement Ruling directed parties to address four specific questions related to the Staff Proposal and any relevant issues not addressed in the Staff Proposal.

1.1. Summary of Staff Proposal

The Staff Proposal recommends approval of a mandatory biomethane procurement program for California's four large gas IOUs—Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (SWG) (collectively, the Joint Utilities)—to assist the state in meeting the short-lived climate pollutant (SLCP) emissions reduction goals established by SB 1383 (Lara, 2016).[4] The Staff Proposal would require the Joint Utilities to procure biomethane produced from organic waste for their core customers[5] to help meet

[3] *See* Pub. Util. Code Section 651 (b): https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=651.&lawCode=PUC.

[4] Methane is an SLCP.

[5] Definitions of "core" and "noncore" customers can be found in the glossary of the 2020 California Gas Report. The definitions are consistent with the definition for "core" in

Footnote continued on next page.

California's statutory obligation to divert 75 percent of 2014 organic waste levels away from state landfills by the end of 2025.

After the Joint Utilities have met the 2025 procurement target for biomethane sourced from organic waste diverted from landfills, the Staff Proposal would allow them to procure biomethane from any source other than dairy operations while still prioritizing procurement of biomethane from organic waste diverted from landfills. Dairy biomethane is excluded, as it is currently incented for use in CARB's Low-Carbon Fuel Standard (LCFS) program for transportation-related purposes. By 2030, the Joint Utilities would be required to procure 72.8 billion cubic feet (Bcf) of biomethane annually,[6] which the Staff Proposal states is equivalent to approximately 12.3 percent of total annual statewide gas IOU core customer consumption in 2020.

The Staff Proposal would require all biomethane procurement to be cost-effective according to a methodology to be developed by the Joint Utilities and approved by the CPUC. All biomethane procurement contracts would be submitted for approval by advice letter at tiers determined by the cost of each contract. Each gas IOU would also be required to submit a biomethane procurement plan for CPUC approval outlining its biomethane procurement

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D.86-12-009. Core customers use less than 20,800 therms per month and are generally residential and small commercial operations. Noncore customers are generally commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements. *See*: https://www.socalgas.com/regulatory/cgr.

[6] This volume derives from CARB's target of an estimated four million metric ton carbon dioxide *equivalent* ($MMTCO_2e$) greenhouse gas (GHG) reduction from avoided landfill methane emissions identified in CARB's 2017 Scoping Plan by redirecting 27 million tons of organic waste from landfills, 18 of which must go to compost, anaerobic digestion, co-digestion, wood chipping, or other organic waste processing facilities.

strategy through 2030 and the anticipated bill and rate impacts associated with that procurement. To be eligible to contract with an IOU, biomethane producers would have to meet several eligibility conditions. In 2025, the CPUC would revisit the procurement targets and adjust them, as necessary, in response to market conditions.

1.2. Parties Responding to Staff Proposal

On June 30, 2021, comments were received from the following parties: Agricultural Energy Consumers Association (AECA); Anaergia Services (Anaergia); Bioenergy Association of California (BAC); California Association of Sanitation Agencies (CASA); Central California Asthma Collaborative, Food & Water Watch, Leadership Counsel for Justice and Accountability (collectively, LCJA); Clean Energy; Coalition for Renewable Natural Gas (CRNG); Dairy Cares; Electrochaea Corporation (Electrochaea); Environmental Defense Fund (EDF); Gas Technology Institute (GTI); Joint Utilities; Shell Energy North America (Shell); Sierra Club; The Utility Reform Network (TURN); and True North Renewable Energy (True North). Lawrence Livermore National Laboratory (LLNL), a non-party, also served comments on the service list.[7]

On July 16, 2021, reply comments were received from the following parties: AECA; BAC; California Bioenergy LLC (CalBio); CASA; Clean Energy; CRNG; Dairy Cares; EDF; Electrochaea; Indicated Shippers, California Manufacturers & Technology Association (collectively, Indicated Shippers); Joint Utilities; LCJA; Maas Energy Works (MEW); Shell; Sierra Club; Southern California Generation Coalition; and True North.

[7] Nothing in this decision relies on LLNL's comments.

2. Issues Before the Commission

2.1. Issues Specified in the Original Phase 4 Scoping Memo

The original Phase 4 Scoping Memo issued November 21, 2019, directed parties to address the following seven issues:

1. What are appropriate biomethane procurement targets for each gas corporation?

2. Could the procurement targets be met by any renewable gas that complies with applicable pipeline injection standards?

3. The recommendations developed pursuant to Health and Safety Code Section 39730.8 (Pub. Util. Code Section 651(b)(1).)

4. Are the targets or goals consistent with waste disposal requirements of Health and Safety Code 39730.6 and regulations adopted pursuant to Public Resources Code 42652.5. (Pub. Util. Code Section 651(b)(2).)

5. How to determine if the biomethane procurement meets the requirements set forth in Pub. Util. Code Section 651(b)((3)(B)(i)?

6. How to demonstrate that the biomethane procurement meets at least one of the requirements of Pub. Util. Code Section 651(b)(3)(B)(ii)?

7. How will IOUs recover the costs of meeting procurement targets? What is the expected impact on rates?

2.2. Issues Specified in the Amended Phase 4 Scoping Memo

The amended Phase 4 Scoping Memo issued June 5, 2020 added the following seven additional issues:

1. Whether to base a procurement target on greenhouse gas (GHG) emission reductions achieved, rather than gas volume, or adopt other provisions to ensure that GHG reductions are maximized?
2. Which biomethane sources have the greatest short-lived climate pollutant reduction benefit? Should procurement be limited to, or prioritize, those sources?
3. How to ensure there are environmental benefits from the procurement that accrue to the utility and/or its customers, and are not used or claimed by another entity?
4. What fuel certification and verification measures are appropriate?
5. What are reasonable estimates of the supply of biomethane available to meet a procurement target as well as meet other demands, including for alternative vehicle fuels?
6. How can we ensure that the procurement will not frustrate or conflict with efforts to decarbonize buildings through electrification?
7. How can we ensure that the impact of meeting procurement targets on rates paid by consumers is reasonable?

The Staff Proposal addresses these issues under three broad headings: (1) Cost-Effectiveness, (2) Procurement Targets, and (3) Other Considerations. We consider each in turn.

3. Discussion and Analysis

3.1. Staff Proposal

3.1.1. Staff Cost-Effectiveness Proposal

The Staff Proposal finds that biomethane "procurement can be cost-effective when compared to the social cost of methane."[8] However, it recommends that the CPUC use the social cost of methane for procedural review such that procurement contracts must be scrutinized in a uniform cost-effectiveness test to determine whether the biomethane procured is "least-cost with the most GHG-reducing benefit."[9]

The Staff Proposal recommends that the Joint Utilities develop a uniform Standard Biomethane Procurement Methodology (SBPM) for determining the cost-effectiveness of procuring biomethane and submit it for CPUC approval as a Tier 2 Advice Letter. The SBPM would serve as the cost-effectiveness test that determines whether the biomethane procured provides the most GHG reduction benefit at the least cost. It would require analysis of factors such as the price of natural gas, costs associated with transporting the gas, the cost of biomethane, the cost of emissions compliance, and the carbon intensity (CI) of the biomethane. The uniform SBPM would have inputs, outputs, and transparency by using a model similar to the Oregon gas utility NW Natural's cost-effectiveness test but would need to be modified to incorporate California-specific procurement requirements, including benefits such as SLCP reductions and environmental justice considerations.

The Staff Proposal does not propose allocation of gas IOU biomethane procurement costs among noncore customers, noting that the CPUC cannot

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[8] Staff Proposal at 28.

[9] *Id*. at 42

direct procurement decisions by entities that supply gas to noncore customers. However, it adds that "[i]f 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."[10]

Regarding the contract approval process, the Staff Proposal recommends that individual biomethane procurement contracts should be submitted for CPUC approval using a three-tier advice letter process:

A Tier 1 Advice Letter for prices up to $17.70/MMBtu, based on market estimate of average cost of biomethane.

A Tier 2 Advice Letter for prices higher than $17.70 but not exceeding $26/MMBtu, the latter reflecting the social cost of methane.[11]

A Tier 3 Advice Letter for prices above $26/MMBtu.

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[10] Staff Proposal at 51.

[11] The $26/MMBtu value is based on the most recent 2021 federal Interagency Working Group (IWG) estimate of the social cost of methane and will be adjusted based on subsequent federal updates thereto. "Social cost of methane" as used herein means the monetary value of the net harm to society associated with adding a small amount of methane to the atmosphere in a year. In principle, it includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. *See* February 2021 report of the federal Interagency Working Group on Climate Change available here: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

3.1.2. Staff Procurement Proposal

3.1.2.1. Short-Term Procurement

The Staff Proposal recommends a short-term target of procuring sufficient biomethane to divert eight million tons of organic waste from landfills to support the 2025 California Department of Resources Recycling and Recovery (CalRecycle) organic waste diversion goal established by SB 1383 (Lara, 2016). CalRecycle estimates that the state's infrastructure (including feasible infrastructure for composting and other alternatives) will be able to process 10 million tons of organic diverted waste in 2025, well short of its goal of 18 million tons diverted.[12] Thus, achieving the Staff Proposal's recommended short-term target would make up for the projected shortfall in organic waste diversion.[13] The Staff Proposal states that "[b]ased 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."[14]

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[12] SB 1383 requires CalRecycle to divert 75 percent of 2014 levels of organic waste.

[13] "CalRecycle estimates …approximately 18 million tons of organic waste that will need to be processed at compost, [anaerobic digesters] AD, or chip-and-grind facilities. However, based on current capacity projections, the state will only be able to process about 10 million tons of this material." Thus, based on a projected 2025 shortfall in infrastructure capacity at compost, AD, or chip-and grind facilities, there is a need for additional capacity for eight million tons of organic waste diverted from landfills. *See* CalRecycle "Analysis of the Progress Toward the SB 1383 Organic Waste Reduction Goals" (2020), https://www2.calrecycle.ca.gov/Publications/Download/1589.

[14] Staff Proposal Footnote 202 at 47. "SWRCB" refers to the California State Water Resources Control Board.

3.1.2.2. Medium-Term Procurement

The Staff Proposal recommends a procurement target of 75.5 million MMBtu (72.8 Bcf) of biomethane annually by 2030, which corresponds to four million metric tons of CO_2 combustion emissions reductions from displaced fossil natural gas use. Feedstocks eligible for the medium-term procurement target include the waste sources defined in Pub. Util. Code Section 650. The gas IOUs would be required to continue prioritizing the procurement of biomethane sourced from organic waste diverted from landfills to meet the medium-term target but would be allowed to procure from most other sources, as well. Dairy biomethane would not be eligible for meeting the medium-term procurement target because it currently commands a high price in the LCFS program. Should landfill gas be procured after 2025, the Staff Proposal recommends that landfill operators be required to use technologies to better capture methane emissions and better optimize operations.

3.1.2.3. Procurement Guidelines

The Staff Proposal recommends that 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 impacts. The Staff Proposal asserts that procurement decisions should use a holistic approach by taking into consideration the ways in which lifecycle biomethane production would contribute to or detract from economic, health, and non-energy benefits for local communities.

3.1.3. Other Staff Recommendations

3.1.3.1. Carbon Monoxide Limit

The Staff Proposal recommends adopting an interim permissible amount of carbon monoxide (CO) in biomethane of 0.03 mole percent, in accordance with Battelle Columbus Laboratories research. This CO standard would remain in place until the Office of Environmental Health Hazard Assessment (OEHHA) and CARB are able to assess the potential dangers of CO and other chemicals associated with bio-synthetic natural gas (bio-SNG) production. The Staff Proposal further recommends 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.

3.1.3.2. Hydrogen Sulfide Limit

The Staff Proposal recommends requiring that the Joint Utilities only procure biomethane from producers who contractually limit hydrogen sulfide (H_2S) concentrations in biogas entering their gathering lines[15] to 10 parts per million (ppm) to match federal Occupational Safety and Health Administration (OSHA) allowable work limits over an eight-hour period and industry standards. The Staff Proposal asserts that H_2S is a toxic chemical that is dangerous to human health and safety, thus the CPUC should require the Joint Utilities to procure only from sellers that agree to limit H_2S to 10 ppm in their gathering lines, as is required for biomethane projects in the San Joaquin Valley Air Pollution Control District that participate in the California Department of Food and Agriculture's Dairy Digester Research and Development Program.

3.1.3.3. Biomethane Procurement Plan

The Staff Proposal recommends requiring that each of the Joint Utilities submit a Biomethane Procurement Plan (BPP) that contains estimated annual biomethane procurement levels, ratepayer bill impacts, and any incremental

[15] Gathering lines are lines used to transport biomethane from its source to the gas utility where it can be combined with methane from other sources for delivery to customers. Pub. Util. Code Section 950 (a)(3) defines a "gathering line" as "a pipeline that transports gas from a current production facility to a transmission line or main."

capital infrastructure and/or operations and maintenance costs associated with those procurement levels through the end of 2030. According to the Staff Proposal, these BPPs should be submitted as Tier 3 Advice Letters.

3.1.3.4. Tipping Fees

The Staff Proposal recommends requiring contingencies in biomethane procurement contracts to account for increases in tipping fees[16] such that the procurement price lowers if tipping fees are raised. Both tipping fees and biomethane sales generate revenue for a biomethane production facility. Thus, the Staff Proposal asserts that a contingency to renegotiate contracts when tipping fees change can help offset revenue increases or decreases to support biomethane producers while also protecting consumers.

3.1.3.5. Prohibition of Diesel Vehicles

The Staff Proposal recommends prohibiting the Joint Utilities from procuring biomethane from any production facility that does not commit to the prospective exclusive use of low-carbon fuel or zero-emission vehicles as part of any expanded operations.

3.1.3.6. On-Site Generator Restrictions

The Staff Proposal recommends that the Joint Utilities prioritize procurement of biomethane from facilities that agree to not increase on-site electric generation produced by gaseous combustion so as to avoid air quality impacts to local communities.[17] A facility would be allowed to increase on-site

[16] Tipping fees are the fees charged by a landfill to accept waste. Per the Staff Proposal, a "tipping fee" is a fee paid by anyone who disposes of materials at a waste processing facility.

[17] A CEC study found that "biogas and biomethane combustion exhaust is similar to natural gas combustion exhaust." 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

Footnote continued on next page.

electric generation using biomethane—not raw biogas—in a fuel cell that does not combust the gas.

3.1.3.7. Carbon Capture and Storage Requirements

The Staff Proposal recommends that the Joint Utilities prioritize procuring biomethane from producers that use carbon capture and storage (CCS) because California's geography in many areas is well-suited for CO_2 storage.

3.1.3.8. Core Transport Agent Requirements

The Staff Proposal recommends requiring Core Transport Agents (CTAs) to meet or exceed the level of biomethane procured by the gas IOU that they are competing with in their customer offerings. The Staff Proposal notes that the CPUC does not have express statutory authority over CTA procurement and, accordingly, recommends the adoption of legislation to provide it this authority.

3.1.3.9. Soil Amendment Requirements

The Staff Proposal recommends that the Joint Utilities prioritize procurement of biomethane from production facilities that agree to convert their waste byproduct into soil amendment such as biochar.

3.1.3.10. Pilot Projects for Converting Biomass to Biomethane

The Staff Proposal recommends that California's two largest gas IOUs—SoCalGas and PG&E—each submit an application to the CPUC by no later than the end of 2022 for one pilot project that can convert forest waste and any available agricultural waste into biomethane. The pilot projects would be required to be strategically located to process maximal waste amounts, and SoCalGas and PG&E would be required to consult with state and local

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Commission. Publication Number: CEC-500-2020-034 at 128. *See*: https://ww2.energy.ca.gov/2020publications/CEC-500-2020-034/CEC-500-2020-034.pdf.

authorities on project locations. The Staff Proposal further recommends that SoCalGas and PG&E propose ways in which any hydrogen or CO_2 produced by the facility would be used instead of vented into the atmosphere.

3.2. Responses to Staff Proposal

3.2.1. Party Responses to Staff Cost-Effectiveness Proposal

Multiple parties, including EDF, CRNG, AECA, LCJA, Sierra Club, Dairy Cares, and Clean Energy, state that there should be a workshop for public testimony, record development, and public review of a cost-effectiveness test. Additionally, EDF and the Joint Utilities assert that a Procurement Advisory Group should be required, as established in Decision (D.) 20-12-022 implementing the Voluntary Renewable Natural Gas Tariff (VRNGT). EDF and the Joint Utilities also assert that, similar to renewable electricity procurement, intervenor compensation should be available for participating parties and that cost containment mechanisms should be implemented to prevent excessive ratepayer impact. Parties state that cost-effectiveness should not be the only metric used for biomethane procurement and recommend various additional factors for the cost-effectiveness test such as SLCP reductions, carbon intensity, additionality, verifiability, and certification. EDF states that low-income customers enrolled in the California Alternate Rates for Energy (CARE) program should be explicitly considered for bill impact.

3.2.2. Party Responses to Staff Procurement Proposal

3.2.2.1. Party Responses to Staff Short-Term Target Proposal

BAC states that the Staff Proposal's short-term target should be resource-neutral because limiting eligible procurement sources to wastewater treatment plants and standalone anaerobic digesters processing organic waste diverted from landfills would make the program overly restrictive. To ensure source diversity, BAC urges the Commission to put a cap on landfill gas procurement. Additionally, BAC notes that Assembly Bill (AB) 1900 states that CPUC "policies and programs shall facilitate the development of a variety of sources of in-state biomethane" (emphasis added).

CRNG supports the proposed short-term target and finds the Staff Proposal recommendation to be reasonable.

Electrochaea calculates that eight million tons of organic waste processed in anaerobic digesters could produce as much as 100 Bcf, which equals approximately five percent of California gas demand in 2019. They assert that the Staff Proposal's short-term target is unclear because it is not a specific volume and could exceed the medium-term target.

The Joint Utilities are concerned that the short-term target will be difficult to achieve by 2025 and request that the CPUC adopt a flexible compliance approach for meeting their procurement obligations.[18]

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[18] "In order for the program to be immediately successful, the Joint Utilities request that the CPUC adopt a flexible compliance approach for the 2025 short-term target. There is much to do between now and 2025. Specifically, the Joint Utilities need to obtain Commission approval of a procurement program via a Proposed Decision and submit the various AL requirements recommended in the Proposal (*e.g.*, development of a Biomethane Procurement Plan (BPP) and SBPM, develop and hold competitive solicitations, negotiate contracts, and seek approvals of Biomethane Contracts). Without flexibility, short-term requirements may lead to higher biomethane prices…. Accordingly, the Joint Utilities request that the CPUC adopt a flexible compliance approach for the 2025 short-term target and 2030 medium-term targets, including the adoption of compliance methods such as banking and borrowing, possible trading excess supplies between the Joint Utilities, and other tools available to manage supply. The Joint Utilities recommend that the Commission direct the Joint Utilities, via the upcoming Decision in this proceeding, to coordinate on a proposed set of these flexible compliance mechanisms to be filed in their BPPs. The Commission would then authorize these mechanisms as part of the BPP approval." Joint Utilities Opening Comments at 4-5.

3.2.2.2. Party Responses to Staff Medium-Term Target Proposal

Party	Response
BAC & GTI	Increase annual target to 150 Bcf by 2030
Anaergia	Increase annual target to 180 MMBtu by 2030
CRNG & CASA	Support annual target at 72.8 Bcf
EDF	Establish after public review
LCJA & Sierra Club	Reject 2030 target and Staff Proposal methodology

LCJA, EDF, and Sierra Club support the short-term organic waste diversion target but argue that setting medium-term targets is premature and needs to be preceded by alternative analyses of issues such as the appropriate feedstocks, the social cost of methane, and environmental justice. EDF makes the additional recommendation "to simply eliminate high carbon intensity fuels (such as purpose grown crops)."[19]

CalBio, MEW, Dairy Cares, CRNG, and AECA object to excluding dairy biomethane from medium-term targets. BAC and Shell request resource-neutral procurement. Clean Energy's reply comments recommend procuring dairy biomethane to help mitigate the poor air quality in communities surrounding dairies, an issue that LCJA and Sierra Club raise also in their opening comments.

3.2.2.3. Party Responses to Procurement Guidance

TURN, Shell, CRNG, AECA, Dairy Cares, Clean Energy, LCJA, Sierra Club, True North, Electrochaea, and the Joint Utilities all support biomethane

[19] EDF Opening Comments at 10.

procurement policies that maximize benefits for communities in which biomethane is produced.

LCJA and EDF request a workshop on environmental justice, including impacts of the proposed procurement on disadvantaged communities from the proposed procurement.

CRNG raises a concern that including CI scores in a cost-effectiveness test may unduly delay procurement. They assert that a complex and thorough analysis of life cycle GHG emissions is required before CI scores can be established in a California-specific Greenhouse Gases, Regulated Emissions and Energy Use in Transportation Model (GREET) pathway.[20] As such, an interim method may be necessary in order to encourage accelerated biomethane procurement.

3.2.3. Party Responses to Other Staff Recommendations

3.2.3.1. Carbon Monoxide Limit

The Joint Utilities support an interim CO limit in the gas quality standard while OEHHA and CARB assess CO and other potential constituents of concern in bio-SNG.

EDF opposes an interim permissible amount "until it is certified" and proposes a "Green-E standard… to consider how bio-SNG comports with that standard as well."[21]

[20] The CA-GREET model is a California-specific version of Argonne National Laboratory's GREET life cycle model which is used to calculate GHG emissions under the LCFS. *See*: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

[21] EDF Opening Comments at 6.

CRNG recommends that CO should be studied in forest pyrolysis pilot projects.

3.2.3.2. Hydrogen Sulfide Limit

Parties that agree with the proposed requirement include BAC, EDF, AECA, LCJA, and Dairy Cares.

EDF agrees with the Staff Proposal that the Joint Utilities' can require the H_2S limit in gathering lines through an agreement between the utility and seller.

The Joint Utilities point out that in D.17-12-007 the CPUC decided to allow dairy biomethane pilots to include treatment of H_2S in the biogas collection line costs but did not mandate this treatment until such time as the gas enters the utility pipeline system.

3.2.3.3. Biomethane Procurement Plan

The recommendation for a BPP requirement is supported in varying degrees by BAC, CRNG, EDF, TURN, AECA, and True North. EDF proposes renaming the proposed BPP as the "Gas Procurement Plan" to avoid confusion with "bundled procurement plan," which is commonly referred to as "BPP" in regulatory parlance. TURN and AECA stress the need for the plan to include forecasts of ratepayer impacts. True North urges the Commission to include consumer education focused on diverting food waste from landfills as part of any plan.

LCJA and Sierra Club oppose approving a procurement plan via the use of advice letters and, like Dairy Cares, insist on a public proceeding such as a formal application to establish an evidentiary record for public analysis.

CRNG supports the Staff Proposal's recommendation that the Joint Utilities publicly file annual progress reports of 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 costs in the BPP.

3.2.3.4. Tipping Fees

AECA, LCJA, and Dairy Cares support renegotiating contract prices if landfill tipping fees are increased.

Anaergia, BAC, and CRNG oppose this recommendation, stating that renegotiating contracts adds uncertainty, risk, and volatility to the contracts. They assert that certainty in long-term contracts should be prioritized.

3.2.3.5. Prohibition of Diesel Vehicles

BAC, CRNG, and LCJA support the prohibition on diesel vehicles for any newly purchased or leased vehicles associated with biomethane production facilities. While EDF opposes this prohibition within the scope of this proceeding, they propose—alongside Sierra Club and LCJA—a more stringent requirement that biomethane production facilities exclusively use zero-emission vehicles.

3.2.3.6. On-Site Generator Restrictions

CRNG and LCJA support limiting increased electric generation from on-site combustion. LCJA recommends this especially for facilities located in non-attainment areas under the Clean Air Act.

BAC supports limiting increased electric generation from on-site combustion yet finds that it may be too restrictive, especially for wastewater treatment facilities that may need to prioritize on-site electric generation needed to maintain essential services over other biomethane end-uses of the feedstock. BAC recommends other non-combustion technologies such as linear generators and proposes expanding non-combustion generation beyond one specific type of technology.

CASA raises an additional issue. It asserts that the regulations of the California Division of Occupational Safety and Health (CalOSHA) are burdensome for facilities that inject more than 10,000 pounds of methane into gas IOU pipelines. An exception to the CalOSHA regulations allows facilities to subtract methane used for onsite electricity production; therefore, this may be the best option at some facilities.[22]

EDF, AECA, and Dairy Cares join CASA in expressing concern that limiting electric generation from on-site combustion may be overly restrictive and difficult to monitor and enforce.

3.2.3.7. Carbon Capture and Storage Requirements

BAC and CRNG support the CCS requirements but believe they should be modified to include carbon use (carbon capture and use or storage ("CCUS")) and that this modification should be included in CI scoring. LCJA and EDF oppose CCS-related procurement prioritization because it is not yet a fully operational solution in California.

3.2.3.8. Core Transport Agent Requirements

CRNG, Shell, Joint Utilities, and BAC support requiring biomethane delivered by CTAs to meet or exceed the quantity of biomethane procured by the Joint Utilities and would support new legislation to that end. EDF agrees with this requirement but believes that legislation is required to enact this proposal.

The Joint Utilities and BAC recommend that the Commission adopt a nonbypassable charge that would allocate some of the gas IOUs' biomethane procurement costs to CTA and noncore customers until legislation is adopted

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[22] Presumably, if the amount of biomethane a facility injects into IOU pipelines is limited, there could be an increase in on-site electricity production when the facility begins processing larger volumes of organic waste diverted from landfills.

requiring CTAs procure the same amount of biomethane as the gas IOUs. BAC recommends a similar nonbypassable charge imposed in the BioMAT program.

3.2.3.9. Soil Amendment Requirements

CRNG, AECA, and Dairy Cares support using biosolids produced from the feedstocks as a soil amendment.

CASA supports the use of digestate, which they assume includes biosolids, as a soil amendment.

BAC proposes a modification for byproduct reuse to include end uses such as water purification, cement, or other industrial purposes. The byproduct end-use should be decided on a project-by-project basis.

LCJA disagrees with the Staff Proposal's soil amendment recommendation because farm-derived waste byproduct is already used as a soil amendment. They further assert that nutrients and other compounds in digestate have a higher chance of leaching or running into ground or surface waters compared to undigested manure.

3.2.3.10. Pilot Projects for Converting Biomass to Biomethane

EDF, GTI, AECA, BAC, and the Joint Utilities support the Staff Proposal's two recommended pilot projects for woody biomass pyrolysis or gasification.

AECA, CRNG, Shell, and Dairy Cares remain neutral on the issue.

BAC recommends expanding the pilot program by including other sources of wood waste such as forest, agricultural, and urban wood waste in six pilot projects, similar to the dairy biomethane pilot projects approved by the CPUC in response to SB 1383. They state that "a plan to phase out the open burning of agricultural waste by 2025. . . calls specifically for increased bioenergy development as a preferable alternative to open burning. Indeed, for many forms of agricultural waste, bioenergy is the only alternative to open burning (which emits black carbon and methane) or pile and decay (which emits methane)."[23]

Sierra Club opposes the Staff Proposal's two recommended pilot projects and asserts that forest thinning for fuels reduction is a net carbon emission from the forest. In lieu of producing methane from woody biomass, Sierra Club recommends other solutions for wood waste such as soil amendments and compost.

3.2.4. Issues Not Addressed by the Staff Proposal

Parties raised six additional matters not addressed in the Staff Proposal, which we address in turn.

3.2.4.1. Methane Leaks

CRNG, EDF, Sierra Club, LCJA, and True North raise concerns that methane leaks from biomethane facilities or pipelines will exacerbate climate-related efforts. EDF proposes a leak rate limit and a requirement that the seller demonstrate sufficient air quality permits to enable operations, particularly at the point of injection. CRNG proposes factoring methane leaks into a CI score to incorporate facility leakage monitoring into the life cycle analysis, thereby providing an incentive to minimize leaks associated with biomethane production and pipeline injection. EDF proposes periodic inspection against leakage at points of interconnection and monitoring to ensure environmental integrity through the life of the contract.

[23] BAC Opening Comments at 7.

3.2.4.2. Integration With the Voluntary Renewable Natural Gas Tariff

CRNG, EDF, and the Joint Utilities each filed comments requesting that biomethane procured for SB 1440 be allowed to layer with procurement for the VRNGT.

3.2.4.3. Compressed Natural Gas Fueling Stations

In the Joint Utilities' opening comments, SoCalGas and SDG&E request that the CPUC make the compressed natural gas (CNG) fueling station pilot program approved in AL 5295-G permanent in this decision.[24]

3.2.4.4. Renewable Thermal Certificate Tracking

The Midwest Renewable Energy Tracking System (M-RETS), a proprietary web-based platform that tracks Renewable Energy Certificates (RECs) and Renewable Thermal Certificates (RTCs), filed comments in response to a December 17, 2019 ALJ ruling permitting additional comments on SB 1440 implementation. M-RETS recommends that California use their transparent system that issues unique traceable digital certificates to verify carbon intensity pathways such as GREET and compliance with SB 1440. Additionally, "M-RETS users retire Certificates to comply with state policy or to serve the voluntary market and to ensure that Certificates are not double-counted."[25]

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[24] While the Joint Utilities only mention AL 5295-G, the Staff Proposal points out that a similar request was granted for PG&E in response to AL 3961-G.

[25] M-RETS January 10, 2020 Comments at 3.

3.2.4.5. Contract Duration

Party	Response
Anaergia	20 years
GTI	Up to 20 years
BAC	10, 15, or 20 years
EDF & CRNG	10 years

BAC states, "[b]iomethane producers should be able to choose between 10, 15, and 20-year contracts similar to the BioMAT and ReMAT programs. Offering only 10-year contracts is unlikely to attract many biomethane producers, especially in the highest value and more expensive feedstock categories."[26] BAC further asserts that contracts should include an inflation adjustment adder.

3.3. Adopted Courses of Action

3.3.1. Adopted Actions on Cost-Effectiveness

We agree with the Staff Proposal and find that the recommended biomethane procurement targets are a cost-effective means of reducing SLCPs and other GHG emissions, as required under Pub. Util. Code Section 651 (a)(1). Notably, the statute does not require the Commission to find that the targets are the *most* cost-effective means, but simply a cost-effective means. The statute does not describe the elements of "cost-effectiveness," but it is reasonable to include factors other than the monetary cost.[27] The social cost of methane is one option to consider as a preliminary threshold for cost-effectiveness due to an anticipated shortfall in 2025 infrastructure capacity and a dearth of options for methane reductions in organic waste. We agree with the Staff Proposal that provides

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[26] BAC Opening Comments at 15.

[27] For example, in the context of proposed legislation on procurement, the Legislature sought analysis on "the most cost-effective means to achieve the desired outcomes, including costs and benefits beyond the electricity market and nonmonetary benefits such as improvements in environmental quality, public health, and climate stability."

preliminary cost-effectiveness analysis, taking into consideration "(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."[28] As noted above, CalRecycle has estimated that the feasible organic waste diversion expected in 2025, including through composting and other methods, is 10 million tons and has identified a need for processing capacity for an additional 8 million tons of organic waste. From a ratepayer perspective, benefits also include cost savings from reduced upstream interstate transmission use, avoided Cap-and-Trade payments due to decreased fossil fuel use, and avoided fossil gas commodity cost. These benefits offset some of the higher costs for biomethane relative to fossil natural gas. From a societal perspective, the average cost of biomethane ($17.70/MMBtu) is less than the social cost of methane ($26/MMBtu). Because these additional benefits, along with the value of the avoided social cost of methane, will exceed the average cost of biomethane, we find that the adopted procurement program is cost-effective. In sum, we find that the targets are a cost-effective means of achieving the forecast reduction in the emissions of SLCPs and GHGs. They satisfy the requirements of Pub. Util. Code Section 651 (a) and comply with all applicable state and federal laws.

Although the targets meet the threshold statutory requirements, more work is necessary to ensure that every biomethane contract entered into by the Joint Utilities is cost-effective and takes into consideration the various perspectives and factors that parties recommended such as SLCP reductions, carbon intensity, and air quality improvement in disadvantaged communities.

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[28] SB 1440 Staff Proposal at 25.

As such, we require the Joint Utilities to jointly produce an SBPM that takes into consideration the above factors as part of establishing a formal and more fully developed standardized cost-effectiveness test for individual contracts and biomethane procurement planning purposes. We agree with the Joint Utilities and others that a cost-containment mechanism should be established in the SBPM to provide flexibility to avoid excessive rate increases.

We agree with party comments that various complex issues such as cost-effectiveness and environmental justice must be addressed in a public forum with an opportunity for parties to submit comments before finalizing program requirements. Accordingly, we require the Joint Utilities to host a workshop on a standard cost-effectiveness test within 45 days of the effective date of this decision so that the CPUC can remain a neutral arbiter in its assessment of the resulting SBPM. The SBPM workshop may take place over multiple days to accommodate the complexity of the issues and shall be separate from the workshop required pursuant to the adopted actions in Section 3.3.3.3.

The SBPM workshop shall include panelists from each of the following types of groups: gas IOUs, environmental advocates, environmental justice advocates, biomethane producers and consumer advocates. In addition, the public shall be invited to participate in question-and-answer sessions. Topics to discuss at the workshop shall include, but not be limited to, the following:

1. What specific items should be required in the SBPM cost-effectiveness test?
2. How should CI be measured in the SBPM cost-effectiveness test?
3. What criteria shall be used in a modified GREET model and who shall be tasked with developing the model?

4. What cost control mechanisms such as above market cost caps or rate increase limits should be used for each gas IOU?

The SBPM workshop agenda shall include discussion of environmental justice and community benefits related to biomethane procurement. Within three months of the SBPM workshop, the Joint Utilities shall file a joint Tier 2 Advice Letter with a workshop report, feedback received at the workshop, explanations about how the feedback is incorporated into a cost-effectiveness test, and the resulting standardized cost-effectiveness test establishing the SBPM. The advice letter will remain eligible for protest and public comment in accordance with General Order 96.

We agree with TURN and the Joint Utilities that the CPUC should consider distributing above-market biomethane procurement costs to noncore customers "by either including the costs in the gas public purpose program or in a new nonbypassable charge that all noncore and CTA customers must pay"[29] or by some other means. However, we find that it is more appropriate to address this issue in a separate ratesetting proceeding. A new ratesetting proceeding shall be opened to address the topic of noncore cost sharing of biomethane procurement costs.

Additionally, we authorize the establishment of a balancing account with two subaccounts, one for each of the Joint Utilities to record (1) above-market commodity biomethane costs and (2) program administrative costs necessary to support both general biomethane procurement and the specific pilot projects discussed in Section 3.3.3.10 below.

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[29] TURN Opening Comments at 11.

We agree with the Staff Proposal and True North that biomethane procurement contracts should be submitted according to the proposed three-tier advice letter process and clarify that the tiers are neither a cost-effectiveness test nor a method for prioritizing projects. Rather, the tiers are merely a procedural mechanism for the CPUC to review contract submissions.

We also agree with EDF and the Joint Utilities that a Procurement Advisory Group (PAG), as established in the Voluntary Renewable Natural Gas Tariff (VRNGT) decision (D.20-12-022), should be required for biomethane procurement authorized by this decision. In contrast to the PAG established in D.20-12-022 for VRNGT biomethane procurement, participants in the PAG for biomethane procurement authorized by this decision will be allowed to claim intervenor compensation because it benefits all bundled core customers. For both the short-term and medium-term procurement targets, all the following shall apply:

(1) Each of the Joint Utilities shall create and manage its own PAG;

(2) PAG membership should be limited to non-market participants; and

(3) Prospective PAG members shall apply to and receive approval from the CPUC's Energy Division for PAG membership.

It does not appear warranted to provide commodity cost modifications specific to biomethane commodity prices for California Alternate Rates for Energy (CARE) customers because CARE is a discount applied to the overall customer bill including the cost of commodity. However, consistent with Pub. Util. Code Section 729.1 (g), we require the Joint Utilities to each take into consideration the impact on customer bills of the biomethane procurement authorized by this decision, and we order them to propose appropriate remediation measures in the rate design phase of their next General Rate Case. If the IOUs believe that anticipated or actual bill impacts do not demonstrate the need for further discounts for CARE customers, they shall state that explicitly and provide justification for not recommending additional discounts for CARE customers.

3.3.2. Adopted Actions on Procurement

3.3.2.1. Adopted Actions on Short-Term Procurement

We adopt the Staff Proposal's recommended short-term target of procuring biomethane that achieves eight million tons of organic waste, including wood waste, diverted annually from California landfills, in accordance with Pub. Util. Code Section 651 (b). CalRecycle estimates that organic waste[30] generates approximately 22 therms of biomethane per ton.[31] Using this conversion factor, eight million tons of organic waste converts to 17.6 Bcf, which will serve as the short-term volumetric target for achieving the waste diversion target. Even if a gas IOU meets its volumetric short-term target, it shall not open procurement opportunities to the additional biomethane sources allowed to meet its medium-term target until it can demonstrate that it has diverted its share of the eight-million-ton organic waste diversion responsibility. Each of the Joint Utilities shall be responsible for diverting a percentage of the eight million tons of organic waste equal to its Cap-and-Trade allowance share: SoCalGas 49.26 percent,

[30] "Organic waste" includes food, green material, landscape and pruning waste, organic textiles and carpets, lumber, wood, paper products, printing and writing paper, manure, biosolids, digestate, and sludges. *See* CalRecycle: https://www.calrecycle.ca.gov/organics/slcp/collection

[31] CalRecycle's SB 1383 Rule: California Code of Regulations Section 18993.1 (g)(1)(C). *See*: https://www2.calrecycle.ca.gov/Docs/Web/118371 at 94.

PG&E 42.34 percent, SDG&E 6.77 percent, and SWG 1.63 percent. The Joint Utilities shall procure solely on behalf of their bundled core customers.

We acknowledge that strict adherence to the target may adversely affect biomethane prices if the Joint Utilities are captured customers (i.e., required to purchase limited biomethane supply and accordingly forced to pay above market rates to adhere to a strict or inflexible target). Thus, the Joint Utilities may adopt flexible compliance methods similar to the methods introduced pursuant to SB 1078 (Sher, 2002) for the initial implementation of the Renewables Portfolio Standard (RPS) program (*see* D.03-06-071, Ordering Paragraphs 20-22): (1) utilities are allowed unlimited forward banking of excess procurement; (2) procurement in any year shall be applied first to that year's annual procurement target, with any excess procurement then being used to make up a prior year's deficit, or banked for future use; (3) utilities are allowed to carry over an annual deficit of 25 percent to the next three years without explanation; and (4) utilities are allowed to trade excess supplies among themselves and to procure on behalf of each other. If the 2025 diverted organic waste target is met or can foreseeably be met ahead of schedule, then the option of additional procurement from other eligible biomethane feedstocks is permitted during the short-term target timeframe.

3.3.2.2. Adopted Actions on Medium-Term Procurement

As discussed in the short-term targets section, all procurement shall comply with Pub. Util. Code 651 (b). Party comments cite sources of additional feedstock that were not reflected in the Staff Proposal, such as 15 million tons of woody biomass waste, that will be available annually as a result of forest management, agricultural waste, and urban wood waste. Some parties recommend more aggressive procurement targets to help prevent wildfire emissions that can exacerbate climate change with black carbon, another highly potent SLCP, while others state that setting a medium-term procurement target is premature. We agree with the Staff Proposal that a medium-term target of 72.8 Bcf is reasonable. We agree with Sierra Club and other parties that the medium-term target should factor in building electrification and future decreased core demand. We find that the Staff Proposal 72.8 Bcf short-term target will encourage SLCP reduction in the waste sector while converging with state goals for decarbonizing the building sector. Therefore, we adopt a medium-term target in accordance with Pub. Util. Code 651 (b) for the Joint Utilities to collectively procure 72.8 Bcf by 2030 and beyond, which is approximately 12.2 percent[32] of the Joint Utilities' annual bundled core customer natural gas demand, as forecasted in the 2020 California Gas Report for an average temperature year and adjusted to account solely for bundled core customers.[33] This 12.2 percent medium-term bundled core customer procurement target may be referred to as a "Renewable Gas Standard" (RGS). This target is inclusive of the biomethane procured to meet the short-term target and all bio-SNG procurement, but excludes biomethane procured for transportation customers as part of the LCFS program, whether by a gas IOU or anyone else. Additional organic waste feedstocks beyond those eligible to meet the short-term target will be eligible for medium-term target procurement.

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[32] The Staff Proposal calculated this percentage to equate to 12.3 percent, which we revise to 12.2 percent in this decision.

[33] California Gas Report models two scenarios for forecasting purposes: (1) average temperature year and (2) cold dry year. *See*: 2020 California Gas Report at 21 https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf.

Purpose-grown crops are expressly prohibited as a feedstock for this program.[34] Landfill gas procurement will be limited to landfill facilities that stop accepting new organic waste and implement advanced landfill gas capture automation and monitoring technology to decrease fugitive methane emissions, as recommended in the Staff Proposal.

Mirroring the short-term target procurement standard, the Joint Utilities are responsible for procuring solely on behalf of their bundled core customers. Additionally, the Joint Utilities may adopt flexible compliance methods for medium-term targets: (1) utilities are allowed unlimited forward banking of excess procurement; (2) procurement in any year shall be applied first to that year's annual procurement target, with any excess procurement then being used to make up a prior year's deficit, or banked for future use; (3) utilities are allowed to carry over an annual deficit of 25 percent to the next three years without explanation; and (4) utilities are allowed to trade excess supplies among themselves and to procure on behalf of each other. For annual deficits above 25 percent, the utility will inform Energy Division Staff in a Tier 1 Advice Letter.

We will re-evaluate this target in the current or a successor proceeding to commence in 2025 after taking into consideration progress made toward achieving the short-term target, additional analysis on technical and economic feasibility, market conditions, procurement rules, eligible time periods for contracts, and contract duration and outcomes from the Long-Term Gas Planning Rulemaking (R.20-01-007).[35] Over time, as the total volume of bundled

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[34] Purpose-grown crops may result in net positive greenhouse gas emissions. *See* SGIP decision D.21-06-005 at 29.

[35] The Gas OIR proceeding includes issues such as: Should PUC require IOUs to submit a decarbonization plan that includes plans for selectively decommissioning the distribution

Footnote continued on next page.

core customer gas usage is expected to decrease due to building electrification and other factors (e.g., increased RPS procurement, improved energy efficiency, etc.), maintaining 72.8 Bcf of biomethane per year will result in annual percentages of biomethane that are higher than 12.2 percent. However, the Joint Utilities shall use their best efforts to achieve the 72.8 Bcf medium-term target in 2030, or as soon as possible after this date.

We decline to adopt the Staff Proposal's recommended dairy biomethane exclusion. Instead, we allow dairy biomethane from facilities that commence operation after December 31, 2021 to be procured to meet the medium-term target, but we limit its procurement to not more than four percent (collectively, 2.9 Bcf) of the Joint Utilities' medium-term procurement obligation. We opt to allow eligible dairy biomethane to be procured prior to the formal commencement of medium-term procurement, but any dairy biomethane procurement shall not count toward fulfillment of the collective 17.6 Bcf short-term target and may only be in addition to the non-dairy biomethane procured to meet the 17.6 Bcf short-term target. Neither dairy biomethane nor any other form of livestock-derived biomethane shall be procured in excess of the four percent limit. This procurement limitation shall be revaluated alongside other issues in the current or successor proceeding to commence in 2025.

We agree with LCJA and Sierra Club that matters of environmental justice are of special concern with livestock biomethane. Thus, we require the Joint

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system; setting criteria to determine whether gas infrastructure should be repaired or replaced (one possible factor would be proximity to a source of renewable gas); setting a procedural mechanism to proactively decommission distribution pipelines; setting criteria to determine gas lines with highest priority for proactive decommissioning (criteria could include proximity to a source of renewable gas); whether to require plans for zonal electrification. *See* R.20-01-007 January 5, 2022 Scoping Ruling, Sections 2.1, 2.2 and 2.3.

Utilities use the SBPM workshop to address how to ensure livestock and dairy biomethane facilities that contracts with a gas IOU are not causing adverse impacts to water and air quality. The workshop shall address how to ensure that the dairy biomethane facility does not maintain a herd size that results in manure production that cannot be managed under responsible practices for the land application of manure (that limits applied amounts to not more than what can be absorbed by crops) unless the facility sells the waste byproduct as soil amendment to other parties. The workshop shall establish enumerated requirements, procurement contract provisions, and procedures similar to those adopted in prior CPUC decisions. For example, VRNGT D.20-12-022 states that the Joint Utilities may not procure from a dairy that has an unresolved citation for violation of rules, regulations, laws, or other requirements for protection of air or water quality, or an outstanding order to remedy a discharge of air or water pollutants, from a state or local regulatory agency. The VRNGT decision also requires the Joint Utilities report to the Commission on whether in-state dairies are in compliance with laws and regulations regarding air and water pollution control. Bioenergy Renewable Auction Mechanism (BioRAM) Program in D.18-12-003 and Resolution E-4977 (January 31, 2019 at 15 to16) requires parties to monitor whether facilities providing sustainable forestry feedstock for electric generation complied with air pollution control requirements.

3.3.2.3. Adopted Actions on Procurement Guidelines

We direct the Joint Utilities to include additionality, verifiability, certification, compliance with Pub. Util. Code 651 (b)(3), environmental assessments and social justice impacts as part of their biomethane procurement practices in their respective procurement plans. We adopt the Staff Proposal's recommendation that procurement decisions should take into consideration the ways in which modifications and/or expanded operations at a wastewater treatment plant, landfill, or other facility to increase biomethane production would contribute to or detract from economic, health, and non-energy benefits for local communities. These non-GHG community impacts are important to balance cost-effectiveness metrics. Non-GHG impacts may justify a decision to either not procure or reduce procurement from certain facilities even if they offer a lower cost and/or impose contractual requirements to reduce or avoid adverse community impacts.

We adopt the modified GREET model from the VRNGT program in Ordering Paragraph 1.b.i of D.20-12-022. This model will be used to determine CI scores. The Joint Utilities are directed to report CI scores in their Advice Letters seeking approval of a procurement contract. The CI score for purposes of SB 1440 procurement will be used for contract review and procurement decisions. However, the CI score can change as production facilities change; thus, ongoing CI score management shall be subject to review as part of the current or successor proceeding to commence in 2025. To encourage accelerated procurement while a production facility processes CI calculations under the modified GREET model, and while the modified GREET model is being developed, we direct the Joint Utilities to start procurement as soon as possible, using a preliminary cost-effectiveness test that estimates the SLCP reduction and life cycle carbon emissions until a CI score is established.

The workshop discussed in Section 3.3.1 shall include an additional agenda item to discuss:

5. What criteria shall be used in a preliminary cost-effectiveness test while a modified GREET model is being developed?

3.3.3. Adopted Actions on Other Staff Recommendations

3.3.3.1. Carbon Monoxide Limit

We disagree with the Staff Proposal and the Joint Utilities' opening comments that it is appropriate at this time to adopt an interim permissible amount of CO in biomethane of 0.03 mole percent to account for bio-SNG gas quality. Rather, we direct the Joint Utilities address what an appropriate CO standard for biomethane should be in the next biomethane standards update application submitted pursuant to Ordering Paragraph 7 of D.14-01-034. This application proceeding is dedicated solely to the topic of ensuring that biomethane does not pose a threat to either human health or pipeline integrity and will provide parties with the opportunity to more closely examine the appropriateness of adopting a CO standard.

We agree with the Staff Proposal that additional study of potential constituents of concern in bio-SNG is merited. However, we disagree with the Staff Proposal that one of the Joint Utilities should contract for such a study. We instead authorize the CPUC, in collaboration with OEHHA, to contract with a research institution and/or private company with expertise in bio-SNG research to conduct further study of constituents found in various sources of bio-SNG and/or conduct any necessary laboratory analysis. The contract shall not exceed $1 million. Following formal execution of the contract, the Joint Utilities shall reimburse CPUC for total contract costs. Contract cost responsibility shall be borne from each IOU's respective cost recovery mechanism to recover costs from core and noncore customers annually through the Joint Utilities respective Annual Gas True-Up filings.

3.3.3.2. Hydrogen Sulfide Limit

We agree with the Staff Proposal, BAC, EDF, AECA, LCJA, and Dairy Cares that high levels of H_2S in gathering lines poses a potential safety hazard and should be mitigated to reduce risks to both workers and members of the general public in the vicinity of a gathering line. In the interest of public safety, the CPUC requires the Joint Utilities to explicitly require a biomethane supplier to demonstrate and agree on an ongoing basis that the biogas it produces has its H_2S levels reduced to 10 ppm or less prior to entering a gathering line so as to match industry standards and allowable eight-hour work limits established by OSHA. To formalize this requirement, the Joint Utilities are directed to reflect the new H_2S restrictions in procurement contract advice letter filings. Further, this decision updates the requirements for the biomethane incentive reservation system requirements established in D.19-12-009 for future applications. The Joint Utilities are directed to file Tier 2 Advice Letters within 30 days of the effective date of this decision updating the Incentive Reservation Form to ensure that biomethane producers seeking a monetary incentive acknowledge this new requirement. A biomethane producer who is already on the waitlist to receive a monetary incentive shall be required to acknowledge and comply with this new requirement.

3.3.3.3. Biomethane Procurement Plans

We agree with the Staff Proposal and comments from CRNG, AECA, Dairy Cares, EDF, and the Joint Utilities that procurement plans are necessary for research and analysis regarding economic, GHG, and other related costs and benefits associated with biomethane. We find that a workshop—separate from the workshop adopted pursuant to Section 3.3.1 to establish a cost-effectiveness test—is necessary to provide stakeholders the opportunity to provide input into the development of the Biomethane Procurement Plan, which we rename to "Renewable Gas Procurement Plan" (RGPP) to avoid confusion with the "bundled procurement plan" acronym.

The RGPP workshop shall be hosted by the Joint Utilities and take place within 60 days of the effective date of this decision. The workshop may be multi-day to accommodate the multitude of issues relating to biomethane procurement planning. The RGPP workshop shall include panelists from each of the following types of groups: gas IOUs, environmental advocates, environmental justice advocates, biomethane producers and consumer advocates. In addition, the public shall be invited to participate in question-and-answer sessions. Topics to discuss at the workshop shall include, but not be limited to, the following:

1. What specific items should be required in a template advice letter for all elements of an RGPP, including but not limited to a list of project priorities, cost, and non-economic benefits?
2. What cost control mechanisms, such as cost caps and rate increase limits will be used for each gas IOU?
3. What criteria shall be used in the biomethane procurement plan to verify project viability, high uptime, and accurate deliverability of promised volume of biomethane?
4. What procedure is necessary to ensure additionality and verifiability?

The IOUs shall produce a template RGPP to standardize filings for each utility's RGPP. The template RGPP shall be filed as a Tier 1 Advice Letter within 30 days of the workshop. Draft RGPPs for each of the four Joint Utilities shall be served as public filings submitted to this current or successor proceeding no later than January 1, 2023, after which the draft RGPPs shall be subject to a round of comment and reply comment. Motions to update the draft RGPPs to account for changed circumstances and/or updated information shall be made no later than

45 days from the date that the draft RGPPs were filed, after which a Proposed Decision shall be issued providing specific instructions to each of the Joint Utilities for what to modify and/or include in their final RGPP. No later than 30 days from the effective date of adopting a final decision, the Joint Utilities shall submit their final RGPPs as Tier 1 Advice Letters to the CPUC. The current or successor proceeding to commence in 2025 shall explore whether to make RGPP updates annual or otherwise submitted according to a specific recurring timeline.

Annual reporting previously required by this proceeding under D.15-06-029, as modified by D.16-12-043, shall be updated to include accounting for biomethane procured pursuant to this decision 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 RGPPs.

The Joint Utilities' respective RGPPs shall evaluate feasibility and provide guidance on compliance mechanisms necessary to successfully meet the short-term target adopted in Section 3.3.2.1.

The Joint Utilities may include requirements for their PAG in their RGPPs.

3.3.3.4. Tipping Fees

We disagree with the Staff Proposal that biomethane contracts should be renegotiated if a producer increases its tipping fees. We agree with Anaergia, BAC, and CRNG that such a requirement would add uncertainty and risk to long-term contract pricing and therefore decline to require any contract modification due to tipping fee changes. However, we agree with the Staff Proposal, AECA, LCJA, and Dairy Cares that tipping fees have a direct impact on contract pricing that should not go unaddressed. As such, we require that any biomethane procurement contract between a project developer and an IOU specify how tipping fees may modify contract terms, if at all, and direct staff to scrutinize contracts submitted for formal approval to ensure that each contract meets this requirement.

3.3.3.5. Prohibition of Diesel Vehicles

We agree with the Staff Proposal, BAC, CRNG, and LCJA that the Joint Utilities should be prohibited from procuring biomethane from facilities that do not commit to exclusively purchase and/or lease either near-zero emission (NZE) or zero-emission (ZE) Class 8 trucks used in the production of biomethane prospectively. NZE vehicles must comply with CARB regulations for ultra-low nitrous oxide vehicles. This requirement is specific to the company operating the facility and/or facilities that the biomethane is to be procured from, which may differ from the landowner, and does not necessarily commit the producer to exclusively purchase NZE or ZE vehicles used in other facilities or for other aspects of its operations. Any gas-powered vehicle shall exclusively use bio--CNG rather than fossil gas. The biomethane production facility that the Joint Utilities contract with shall be required to agree to such terms, declare all existing Class 8 trucks currently used in their operations, and inform the IOU it contracts with whenever a new vehicle is purchased or leased for use at the facility from which the biomethane is being procured. It is the intent of the Commission that NZE Class 8 trucks will be allowed only as long as ZE vehicles are not commercially available. As such, the current or successor proceeding to commence in 2025 shall evaluate when to require prospective purchases and/or leases of Class 8 trucks to be exclusively ZE. We direct Energy Division Staff to ensure that contracts that are approved include said provisions.

Additionally, the Joint Utilities are directed to give procurement priority to facilities that can further demonstrate that the waste haulers delivering to the biomethane production facility will adhere to the same prospective exclusive use of NZE or ZE vehicles that the facilities themselves are required to adhere to. The Joint Utilities are required to address how priority would be given to such facilities in their SBPM.

The GHG and environmental benefit of NZE and ZE vehicles shall be added to the CI score, as CRNG recommends, to estimate production facility emissions and create additional incentives for converting previously purchased or leased vehicles to NZE or ZE.

3.3.3.6. On-Site Generator Restrictions

We agree with the Staff Proposal, as well as BAC, CRNG, and LCJA, that the Joint Utilities should prioritize procurement from facilities that agree to prospectively cap on-site electric generation from combustion of biogas or biomethane. We agree with LCJA that such a cap is especially important for facilities located in non-attainment areas under the Clean Air Act. As such, we make this cap a procurement requirement, rather than a priority, to ensure that this program does not exacerbate exceedances of air quality standards for facilities located in a county listed as a severe or extreme federal nonattainment area for particulate matter (PM-10 or PM-2.5) or eight-hour ozone (O_3) in the U.S. Environmental Protection Agency Green Book in any of the three years prior to the date of this decision.[36] We model this requirement on Pub. Util. Code Section 8388 regarding bioenergy facilities generating electricity in the Bioenergy Renewable Auction Mechanism program, which states: "[t]his section shall not

[36] *See*: U.S. Environmental Protection Agency Greenbook list of nonattainment counties by year, available here: https://www3.epa.gov/airquality/greenbook/anayo_ca.html.

apply to facilities located in federal severe or extreme nonattainment areas for particulate matter or ozone" and D.21-06-005, Ordering Paragraph 1.e, in the Self-Generation Incentive Program Proceeding (R.20-05-012).

We further agree with BAC that non-combustion technology should not be limited solely to fuel cells and instead allow this contractual term to be met using a technology-neutral approach. The Joint Utilities shall ensure that contracting facilities must disclose current annual on-site electric generation from the combustion of biogas and/or biomethane and commit contractually to not exceed those levels prospectively. If the Joint Utilities procure from biomethane production facilities that have yet to purchase or plan and construct electric generation infrastructure on the effective date of this decision, those facilities must contractually agree to use only non-combustion technologies for any electric generation on-site. The Joint Utilities are required to address how priority would be given to complying facilities in their SBPM.

Should a facility choose to use one or more fuel cells in its operations, it need not exclusively use the biomethane produced from its own facility. Instead of using its own biomethane, the facility may alternatively opt to use partially treated biogas from its facility that reduces constituents of concern to levels optimal for fuel cell use without necessarily reducing CO_2 to levels necessary for pipeline injection.

3.3.3.7. Carbon Capture and Storage

We agree with the Staff Proposal, as well as BAC and CRNG, that the Joint Utilities should be required to prioritize procurement from facilities that can prevent CO_2 from venting into the atmosphere. We agree with BAC and CRNG that a more expansive requirement should be adopted that includes "use" in addition to capture and storage, and we thus recast this requirement as "CCUS" instead of merely "CCS." Permissible uses of CO_2 that effectively prevent it from entering the atmosphere include, but are not limited to, carbon mineralization, geologic storage, methanation, biofuel production, and industrial or manufacturing applications. The Joint Utilities shall address how to prioritize CCUS in their SBPM.

Methanation of captured CO_2 is eligible for biomethane procurement for both the short-term and medium-term targets. Methane leak measurement and remediation requirements will apply to methanation facilities and pipelines.

The GHG and environmental benefit of CCUS shall be added to the CI score, as CRNG recommends, to determine production facility life cycle carbon emissions and create an incentive for CCUS projects.

The Joint Utilities are required to address in their SBPM how priority would be given to a facility that commits to capturing, storing, or utilizing CO_2 that would otherwise be vented into the atmosphere.

3.3.3.8. Core Transport Agent Requirements

We agree with the Staff Proposal, as well as CRNG, Shell, BAC, and the Joint Utilities that CTAs should be required to meet or exceed biomethane procurement levels of the Joint Utilities. Ideally, legislation should be enacted requiring CTAs to procure biomethane at the same rate as the Joint Utilities, similar to legislation enacted in 2005 that requires Community Choice Aggregators to comply with the RPS compliance obligations established by the Commission. The Office of Governmental Affairs shall work with the Legislature and stakeholders to achieve this objective.

We decline to consider in this proceeding whether a nonbypassable charge for the Joint Utilities' incremental biomethane procurement costs should be imposed on CTA customers as an interim measure. Instead, we intend to explore this issue in a new ratesetting proceeding that will explore the appropriateness of adopting a nonbypassable charge for noncore unbundled gas distribution system customers (*see* Section 3.3.1).

3.3.3.9. Soil Amendment Requirements

We agree with the Staff Proposal, as well as CRNG, AECA, and Dairy Cares that the Joint Utilities should be required to prioritize biomethane procurement from facilities that commit to turning their waste byproduct into soil amendment such as biochar. However, we modify the Staff Proposal recommendation to expand the desirable uses of such waste products beyond converting them into soil amendments to include any GHG-reducing use. To the extent that a biomethane producer can demonstrate that their waste byproduct has had any perfluoroalkyl or polyfluoroalkyl substances (PFAS)[37] removed from it, that producer shall be given added prioritization. The Joint Utilities shall address how to prioritize procurement from such facilities in their SBPM.

3.3.3.10. Pilot Projects for Converting Biomass to Biomethane

We adopt the Staff Proposal's recommendation requiring PG&E and SoCalGas to submit applications for pilot projects that can convert woody biomass into bio-SNG. However, we modify the Staff Proposal recommendation per BAC's request to allow PG&E and SoCalGas to propose more than one pilot project each and to include agricultural waste and urban wood waste diverted from landfills to support wildfire prevention and SLCP reduction. We authorize PG&E and SoCalGas to propose procuring bio-SNG from forest, agricultural, and urban wood waste pyrolysis and gasification projects using methanation, and grant them discretion as to whether to focus primarily on forest or agricultural

[37] *See*: https://www.epa.gov/pfas.

waste in their applications so as to best meet each utility's needs. PG&E and SoCalGas must propose at least one pilot project each. We further grant the Joint Utilities' request to allow those pilot projects to contract with developers for the pilot projects (as opposed to requiring the facility be utility-owned) and extend the deadline to file applications for the pilot projects from January 1, 2023 to July 1, 2023. We also direct the Joint Utilities to explore coordinating the procurement efforts and strategic placement of the pilot projects with local and state authorities, including the Department of Conservation that was authorized by SB 155 (Committee on Budget and Fiscal Review, 2021) to dedicate $50 million for similar purposes. We adopt additional recommendations from the Staff Proposal: (1) project cost should include pipeline extensions to the pilot facilities, (2) pipeline extensions should facilitate future potential extensions for additional projects, and (3) the pilots should propose methods for using CO_2 in CCUS projects rather than venting to the atmosphere.

We recognize that both the commodity cost and interconnection costs for these pilot projects could be considerable if not otherwise mitigated. To help achieve the GHG and criteria air pollutant emission reductions associated with procuring bio-SNG, we direct the Joint Utilities to collectively set aside $40 million from their 2022 Cap-and-Trade allocated allowance auction proceeds so that additional funding is available to offset pipeline build-out costs and related expenses associated with the pilot projects. This one-time redirect of allocated allowance auction proceeds must comply with all applicable CARB regulations. This approach is consistent with both AB 3187 (Grayson, 2018) and Pub. Util. Code Section 784.2, which directs the CPUC to explore options for furthering the goals of Pub. Util. Code Section 399.24 to promote the in-state production and distribution of biomethane and consider whether to allow recovery in rates of the costs of interconnecting biomethane projects. These funding set-asides will reduce the Climate Credit refunded to residential gas customers in 2022 by a small amount, but the average residential customer of each of the Joint Utilities is still anticipated to receive a Climate Credit that will cover at least the full amount of costs that the gas IOUs collected from them for Cap-and-Trade program compliance costs in 2021.

As noted previously in D.20-12-031, multiple parties to this proceeding have requested that the CPUC increase funding for biomethane pipeline interconnection projects using gas IOU Cap-and-Trade allowance proceeds. Conclusion of Law 9 of D.20-12-031 found that the CPUC may use Cap-and-Trade allowance proceeds to increase funding for biomethane project interconnection incentives.

Consistent with past precedent established in both D.20-03-027 and D.20-12-031, the additional one-time $40 million set-aside of Cap-and-Trade allowance proceeds shall be allocated consistent with each IOU's respective percentage of their combined CARB allocation of Cap-and-Trade allowances, which shall be as follows:

- SoCalGas: $19,704,000 (49.26 percent of $40 million)
- PG&E: $16,936,000.00 (42.34 percent of $40 million)
- SDG&E: $2,708,000 (6.77 percent of $40 million)
- SWG: $652,000 (1.63 percent of $40 million)

The full annual allocation for each of the Joint Utilities shall be deducted from the 2022 Climate Credit. Each of the Joint Utilities shall file a Tier 1 Advice Letter within 15 days of the effective date of this decision revising their natural gas 2022 Climate Credit amount to reflect the reduction mandated by this decision. The Joint Utilities' advice letter filings shall modify the table format established by D.15-10-032 (*i.e.*, Table C of Appendix A of that decision, subsequently modified by D.20-03-027 and then D.20-12-031) to include below line 9c a new subaccount line numbered 9d and titled "Bio-SNG Pilot Costs." This line shall record each gas utility's share of the $40 million set-aside, as established by this decision. Line 10 of Table C of Appendix A of D.15-10-032 shall also be modified to equal the Subtotal Allowance Proceeds minus Outreach and Admin Expenses minus SB 1477 Compliance Costs minus RNG Incentive Costs minus Bio-SNG Costs. In order to reflect this change, the Joint Utilities shall further modify the template for Table C by changing the description of Line 10 of Table C of Appendix A of D.15-10-032 to "Net GHG Proceeds Available for Customer Returns ($) (Line 8 + Line 9 + Line 9b + Line 9c + Line 9d)." This requirement regarding the revised table format shall apply to all applicable future filings seeking approval of the natural gas Climate Credit amount for each of the Joint Utilities until or unless the CPUC decides otherwise.

Each of the Joint Utilities shall separately file a Tier 1 Advice Letter within 15 days of the effective date of this decision establishing a new balancing subaccount to track all Cap-and-Trade allowance proceeds set aside pursuant to this decision, as well as any interest accrued on those proceeds.

SDG&E and/or SWG, as wholesale customers of SoCalGas, may direct their respective share of allowance proceeds collected pursuant to this decision to be used to offset pilot project costs in SoCalGas service territory if SDG&E or SWG procure a portion of the biomethane produced from that facility or facilities. Any of the Joint Utilities may request to return unused allowance proceeds to their residential customers in the form of the next Climate Credit if they anticipate those proceeds will go unspent. A gas IOU wishing to return allowance proceeds to its residential customers shall submit a Tier 2 Advice

Letter seeking such approval from the CPUC. Any unspent allowance proceeds shall be returned to ratepayers by December 31, 2032 pursuant to Cap-and-Trade Regulation Section 95893 (d)(8).

3.3.4. Adopted Actions on Issues Not Addressed by the Staff Proposal

3.3.4.1. Methane Leaks

The Joint Utilities shall require biomethane producers to include methane leak detection in lifecycle CI accounting via a modified GREET model. We agree with party comments that methane leaks in the production process or at the point of interconnection should be monitored and factored into the lifecycle analysis for carbon emissions. Additionally, in the procurement contract, Joint Utilities shall establish a procedure for immediate methane leak remediation at the production facility or along that gas pipeline interconnection as the preferred response, and specify required actions if there is no immediate remediation, such as timeline for repair, a graduated fee schedule to promote timely remediation, or payment reductions, etc.

3.3.4.2. Integration With the Voluntary Renewable Natural Gas Tariff

We authorize the gas IOUs participating in the VRNGT program—SoCalGas and SDG&E—to allow all customers that sign up for the VRNGT to contract for more incremental biomethane in excess of SB 1440 targets. Those costs shall be recovered via the terms of the VRNGT program.

3.3.4.3. Compressed Natural Gas Fueling Stations

We decline to rule on the 2018 LCFS pilot arrangement for CNG fueling because this request is outside the scope of this decision.

3.3.4.4. Renewable Thermal Certificate Tracking

We require biomethane producers to track volumetric injections into pipelines through the M-RETS platform and/or another platform identified in the SBPM workshop to be hosted no later than 45 days from the date of adoption of this decision (*see* Section 3.3.1). The data collected will support our efforts to calculate potential gas production based on tons of organic waste. There are numerous studies that estimate technical and economic potential of feedstocks by weight, but relatively less data based on the correlation between tons and volumes of gas produced in a variety of production facilities that range in size, geography, and gas production conditions. Transparent tracking of short-term volumes of biomethane will help the Commission review and/or modify medium-term targets in the current or successor proceeding to commence in 2025.

3.3.4.5. Contract Duration

Procurement contracts should be for a maximum of 15 years, with biomethane deliveries not to exceed beyond 2040. We consider this a reasonable limit that provides flexibility while also providing security in the form of long-term contracts. The maximum contract duration, and eligible time periods for contracts will be revisited in the current or successor proceeding discussed in Section 3.3.2.2.

4. Comments on Proposed Decision

The proposed decision of Commissioner Rechtschaffen in this matter was mailed to the parties in accordance with Pub. Util. Code Section 311 and comments were allowed under Rule 14.3 of the Commission’s Rules of Practice and Procedure. Comments were filed by Agricultural Energy Consumers Association, Anaergia Services, LLC, Bioenergy Association of California,

California Bioenergy LLC, California Manufacturers & Technology Association and Indicated Shippers, Clean Energy, Coalition for Renewable Natural Gas, Dairy Cares, Electrochaea Corporation, Environmental Defense Fund, Food & Water Watch and Leadership Counsel for Justice and Accountability, Gas Technology Institute, Generate Capital, PBC, Midwest Renewable Energy Tracking System, Rural County Representatives of California and Environmental Services Joint Powers Authority, Southwest Gas Corporation, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company ("Joint Utilities"), The Utility Reform Network, True North Renewable Energy, LLC on January 26, 2022. Reply comments were filed by Agricultural Energy Consumers Association, Agricultural Energy Consumers Association, Anaergia Services, LLC, California Manufacturers & Technology Association and Indicated Shippers, Dairy Cares, Environmental Defense Fund, Leadership Counsel for Justice and Accountability, Food & Water Watch, Sierra Club, Southwest Gas Corporation, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company on January 31, 2022. These comments were considered and, where appropriate, revisions were made to the proposed decision.

5. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner in this proceeding and Karl J. Bemesderfer is the assigned Administrative Law Judge.

Findings of Fact

1. Targets or goals shall be consistent with the organic waste disposal reduction target of 18 million tons specified in Section 39730.6 of the Health and Safety Code and the regulations adopted pursuant to Section 42652.5 of the Public Resources Code to achieve those targets.

2. California Department of Resources Recycling and Recovery estimates that the state's infrastructure (including feasible infrastructure for composting and other alternatives) will be able to process 10 million tons of organic diverted waste in 2025, leaving a need for eight million tons of additional organic waste processing capacity to meet 2025 Senate Bill 1383 goals.

3. Four million metric tons of carbon dioxide equivalent converts to emissions from combusting approximately 72.8 billion cubic feet of methane.

4. Methane and black carbon are potent short-lived climate pollutants.

5. Biomethane is defined in Public Utilities Code Section 650 as a biogas that meets the standards adopted pursuant to subdivision (c) and (d) of Section 25421 of the Health and Safety Code for injection into a common carrier pipeline.

6. The primary source of methane for use as a fuel is gas wells.

7. Biomethane and methane from gas wells are chemically identical.

8. Capturing biomethane and substituting it for methane from gas wells reduces the amount of methane entering the atmosphere.

9. Both well gas and biomethane contain impurities that must be removed to meet pipeline gas quality standards.

10. The total cost of a unit of methane from any source includes the direct cost of locating, capturing, treating, transporting, and delivering the gas to an end user, together with the costs of environmental impacts borne by the residents of the areas where the gas is located, captured, treated, transported, and delivered.

11. The cost of well gas must include the utility expenditures for Cap-and-Trade compliance, fossil natural gas procurement, and upstream interstate transmission.

12. The true cost of gas procurement includes the costs to society at large due to the environmental impacts of its production.

13. Methane has an exponentially higher cost to society than biomethane because of its carbon intensity.

14. The federal government's Interagency Working Group states that the social cost of methane is $1500 per metric ton in 2020 using the three percent discount rate, which converts to $26 per million British thermal units (MMBtu).

15. According to the State Water Resources Control Board commissioned study, the average cost of biomethane is $17.70 per million MMBtu.

16. The benefits of the adopted biomethane procurement program include the avoided costs of well gas identified above and the value of the avoided social cost of methane.

17. The Interagency Working Group estimates the social cost of carbon at $51 per ton of emissions in 2020 at the three percent discount rate.

18. Combustion of biomethane and methane creates criteria air pollutants.

19. The Cap-and-Trade allowance proceeds set aside in this decision will be used to reduce statewide greenhouse gas emissions by funding pilot programs to divert agricultural waste and urban wood waste from landfills.

20. The Commission consulted with California Air Resources Board before adopting biomethane procurement targets.

21. Eight million tons of organic waste is estimated to produce approximately 17.6 billion cubic feet of biomethane based on California Department of Resources Recycling and Recovery's conversion formula of 22 therms per ton of organic waste, available in California Code of Regulations Section 18993.1 (g)(1)(C).

22. The potential biomethane procurement in the short-term potentially exceeds 17.6 billion cubic feet because co-digestion with wastewater is estimated to produce higher volumes of methane than with food, green, and paper waste alone.

23. Biogas includes large quantities of carbon dioxide, which can be captured in a relatively pure stream and used or stored.

24. The estimated volume of biomethane produced from eight million tons of co-digested organic waste diverted from landfills to wastewater treatment plants is 32.6 billion cubic feet.

25. Purpose-grown crops could result in net positive greenhouse gas emissions.

26. Decision 21-06-005 prohibits the use of purpose-grown crops to produce fuels used in electric generation.

27. Decision 21-06-005 requires that "the Host Customer maintains exclusive ownership of all environmental attributes from contracted renewable fuel sources and may not sell, trade or transfer any of these attributes."

28. Environmental attributes resulting from this program are at risk of being credited to other carbon reduction programs if they are not utility-owned and not immediately retired.

29. A volume or thermal credit tracking and environmental attribute tracking system can retire environmental attribute credits to prevent double-counting of environmental attributes in this program.

Conclusions of Law

1. Senate Bill 1440 gives the California Public Utilities Commission authority to adopt biomethane procurement targets or goals.

2. Senate Bill 1383 requires California to reduce emissions of methane by 40 percent below 2013 levels by 2030.

3. To meet the state's methane emission reduction goals, biomethane should be substituted for well gas whenever the total cost of a unit of biomethane is equal to or less than the total cost of a unit of well gas.

4. Biomethane may be substituted for well gas even if the total cost of a unit of biomethane exceeds the total cost of a unit of well gas if the substitution is a cost-effective means to enable the state to meet its methane emission reduction goals.

5. The Commission should use the social cost of methane in determining cost effectiveness.

6. To meet the state's methane and black carbon emission reduction goals, the Commission should establish biomethane procurement targets and timetables for the state's investor-owned gas utilities to achieve the targets.

7. Biomethane procurement requirements should comply with Public Utilities Code 651 (b)(3) and should maximize the use of energy from renewable sources.

8. Biomethane procurement requirements should include minimizing the use of equipment powered by fossil fuels.

9. Biomethane procurement requirements should prioritize obtaining biomethane from organic waste diverted from landfills.

10. The just and reasonable cost of biomethane procurement should be evaluated by considering the utility expenditures for Cap-and-Trade compliance, fossil natural gas procurement, and upstream interstate transmission.

11. The just and reasonable cost of biomethane procurement should be evaluated by considering well methane's high costs to society at large due to the environmental impacts of its production.

12. The procurement targets established by this decision are cost-effective means of reducing short-lived climate pollutants pursuant to Section 39730.5 of the Health and Safety Code and reducing other greenhouse gases pursuant to Division 25.5 of the Health and Safety Code.

13. The procurement targets established by this decision are consistent with the waste disposal requirements of Health and Safety Code Section 39730.6 and regulations adopted pursuant to Public Resources Code Section 42652.5 (Public Utilities Code Section 651 (b)(2)).

14. Biomethane procurement requirements should ensure that procurement contracts are individually cost-effective.

15. Biomethane procurement requirements may include any other provisions necessary to ensure the achievement of the state's methane emission reduction goals.

16. Biomethane procurement strategies should maximize benefits for environmental justice and disadvantaged communities.

17. Decision 20-12-031 found that the Commission may use Cap-and-Trade allowance proceeds to increase funding for the biomethane monetary incentive program to reduce statewide greenhouse gas emissions under Section 95893 of the Cap-and-Trade Regulation and Senate Bill 1477.

18. Consistent with the Public Utilities Code Section 651 waste diversion requirement and the Self-Generation Incentive Program (Decision 21-06-005), purpose-grown crops are not an eligible feedstock in this program.

19. To prevent double-counting of environmental attributes, the gas utility procuring biomethane shall maintain exclusive ownership of all environmental attributes from contracted renewable fuel sources and may not sell, trade, or transfer any of these attributes.

O R D E R

IT IS ORDERED that:

1. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall host a workshop on cost-effectiveness within 45 days of the effective date of this decision. The workshop agenda shall be based on the discussion in Sections 3.3.1, 3.3.2.2, and 3.3.2.3 of this decision.

2. Within three months of the cost-effectiveness test workshop, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall include results of the workshop and address feedback received at the workshop in Tier 2 Advice Letters establishing a Standard Biomethane Procurement Methodology.

3. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall include in their Standard Biomethane Procurement Methodology strategies to maximize benefits to environmental justice and disadvantaged communities.

4. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall include in their Standard Biomethane Procurement Methodology a provision giving higher priority to biomethane producers that demonstrate that their waste byproduct will be turned into soil amendment or other reuse, as well as added

prioritization for facilities whose waste byproduct has had perfluoroalkyl or polyfluoroalkyl substances removed from it.

5. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall include in their Standard Biomethane Procurement Methodology a provision giving higher priority to biomethane producers who demonstrate that the waste haulers delivering to their biomethane production facility will adhere to the same prospective exclusive use of near zero emission or zero emission vehicles that the facilities themselves are required to adhere to.

6. We adopt the social cost of methane as the metric for determining cost effectiveness in procuring biomethane.

7. The Commission shall evaluate the Standard Biomethane Procurement Methodology according to ensure it addresses, at a minimum, the cost-effectiveness factors and carbon intensity criteria identified in sections 3.1.1 and 3.3 of this decision.

8. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall include in their Standard Biomethane Procurement Methodology a provision giving higher priority to biomethane producers who prevent CO_2 from venting into the atmosphere using Carbon Capture and Use or Storage projects.

9. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall include in their Standard Biomethane Procurement Methodology a provision requiring livestock and dairy biomethane facilities that contract with a gas IOU to operate in a manner that does not cause adverse impacts to water and air quality.

10. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall require biomethane producers to track volumetric injections of biomethane into pipelines through the Midwest Renewable Energy Tracking System (M-RETS) platform and/or another platform identified in the SBPM workshop to be hosted no later than 45 days from the date of adoption of this decision (*see* Section 3.3.1).

11. The Commission shall evaluate the Standard Biomethane Procurement Methodology according to ensure it addresses, at a minimum, the cost-effectiveness factors and carbon intensity criteria identified in sections 3.1.1 and 3.3 of this decision, as well as short-lived climate pollutant reductions and the requirement that procurement complies with the Public Utilities Code Section 651 (b)(3).

12. Within 60 days of the effective date of this decision, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall host a workshop on the Renewable Gas Procurement Plan (RGPP). The workshop agenda shall be based on the discussion in Section 3.3.3.3 of this decision. Following the workshop, the utilities shall produce a template RGPP to standardize filings for each utility's RGPP. The template RGPP shall be filed as a Tier 1 Advice Letter within 30 days of the workshop

13. The Commission's Energy Division will process individual contracts to procure biomethane through a three-tier advice letter approval process:

- Tier 1 for contract prices up to $17.70/MMBtu
- Tier 2 for contract prices between $17.70 and $26/MMBtu
- Tier 3 for contract prices above $26/MMBtu.

14. The 2025 short-term target for biomethane procurement is 17.6 billion cubic feet (Bcf) annually, produced from eight million tons of organic waste, including wood waste, diverted annually from landfills. This short-term target uses the conversion from California Department of Resources Recycling and Recovery Senate Bill 1383 rule, California Code of Regulations Section 18993.1 (g)(1)(C).

15. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each be responsible for tracking tons of diverted organic waste through tipping fees paid to biomethane production facilities. The tracked tonnage will be used as guidance in meeting the eight-million-ton annual waste diversion goal.

16. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each be responsible for procuring a percentage of the 17.6 billion cubic feet according to each of their respective Cap-and-Trade allowance shares: Southern California Gas Company 49.26 percent, Pacific Gas and Electric Company 42.34 percent, San Diego Gas & Electric Company 6.77 percent, and Southwest Gas Corporation 1.63 percent.

17. The 2030 medium-term target is the Renewable Gas Standard for Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation.

18. By 2030, each of Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall procure each year an amount of biomethane equivalent to 12.2 percent of its own share of 2020 annual bundled core customer natural gas

demand, excluding Compressed Natural Vehicle demand as noted in the California Gas Report (approximately 72.8 Bcf).

19. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation may procure dairy biomethane from facilities that commence operation after December 31, 2021 to meet the medium-term target, but we limit its procurement to not more than four percent (collectively, 2.9 billion cubic feet or Bcf) of their medium-term procurement obligation. Eligible dairy biomethane may be procured prior to the formal commencement of medium-term procurement, but such dairy biomethane procurement shall not count toward fulfillment of the collective 17.6 Bcf short-term target and may only be in addition to the non-livestock biomethane procured to meet the 17.6 Bcf short-term target. Neither dairy biomethane nor any other form of livestock-derived biomethane shall be procured in excess of the four percent limit.

20. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall not procure from a dairy that has an unresolved citation for violation of rules, regulations, laws, or regulatory requirements for protection of air or water quality, or an outstanding order to remedy a discharge of air or water pollutants, from a state or local regulatory agency.

21. Commencing in 2025, the Commission will review the medium-term target in the current or a successor proceeding, taking into consideration progress made toward achieving the short-term target, additional analysis on technical and economic feasibility, market conditions, procurement rules, eligible time periods for contracts and contract duration, and outcomes from the Long-Term Gas Planning Order Instituting Rulemaking 20-01-007.

22. Biomethane produced from purpose-grown crop feedstocks is prohibited from all targets.

23. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation are allowed unlimited forward banking of excess procurement for both short-term and medium-term targets on the following terms:

24. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall apply procurement in any year first to that year's annual procurement target; after meeting the annual procurement target they may use any excess procurement then being used to make up a prior year's deficit, or bank it for future use.

25. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation may carry over an annual procurement deficit of up to 25 percent to the next three years without explanation.

26. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation may trade excess supplies among themselves.

27. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation are allowed to procure on behalf of each other for both short-term and medium-term targets.

28. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall start procurement as soon as possible, using a preliminary cost-effectiveness test developed in the workshop, described in Ordering Paragraph 1, that estimates the short-lived climate pollutant reduction and life cycle carbon emissions until a

carbon intensity score is established and while the modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model is being developed.

29. Before filing the Standard Biomethane Procurement Methodology, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each create a procurement advisory group similar to the one established by Decision 20-12-022. Participants in the procurement advisory group will be allowed to claim intervenor compensation. Energy Division will approve each procurement advisory group participant's membership. Market participants may not become members of a procurement advisory group.

30. Consistent with Public Utilities Code Section 729.1 (g), Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall consider the impact on California Alternate Rates for Energy (CARE) customer bills as a result of the biomethane procurement authorized by this decision. They shall propose any appropriate remediation measures in the rate design phase of their next General Rate Case. If they do not believe that anticipated or actual bill impacts demonstrate the need for further discounts for CARE customers, they shall state that explicitly and provide justification for not recommending additional discounts for CARE customers.

31. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall file their Renewable Gas Procurement Plans (RGPPs) in this proceeding or a successor proceeding no later than January 1, 2023. Motions to update the draft RGPPs to account for changed circumstances and/or updated information shall

be made no later than 45 days from the date that the draft RGPPs were filed, after which a Proposed Decision shall be issued providing specific instructions to each of the utilities for what to modify or include in their final RGPP. No later than 30 days from the effective date of a final decision, the utilities shall submit their final RGPPs as Tier 1 Advice Letters. The current or successor proceeding to commence in 2025 shall explore whether to make RGPP updates annual or otherwise submitted according to a specific recurring timeline in addition to exploring other topics. Concurrent with the filing of the Tier 1 Advice Letter, the Joint Utilities shall each update their currently required annual reports, as required under Decision (D.) 15-06-029, as modified by D.16-12-043, to include details of actual biomethane procurement levels, ratepayer bill impacts, incremental capital infrastructure and/or operations and maintenance costs for the prior year compared to the estimated levels that were approved in their respective RGPPs. Their respective RGPPs shall evaluate feasibility and provide guidance on compliance mechanisms necessary to successfully meet the short-term target adopted in Section 3.3.2.1.

32. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall include in the Standard Biomethane Procurement methodology assessments of the ways in which their biomethane procurement practices affect the environment and increase or decrease the welfare of local communities, including the positive or negative ways in which modifications to a wastewater treatment plan or landfill to increase biomethane production affect those communities.

33. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall

address what an appropriate carbon monoxide standard for biomethane should be in the next biomethane standards update application submitted pursuant to Ordering Paragraph 7 of Decision 14-01-034.

34. One million dollars over three years shall be set aside for a collaboration between the Commission and the Office of Environmental Health Hazard Assessment to contract with a research institution and/or private company with expertise in bio-synthetic natural gas research for a study regarding health-based concentration limits for constituents of concern, namely trace toxic substances including carbon monoxide. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall reimburse the Commission the contract cost of such research up to $1 million from each utility's respective cost recovery mechanism to recover costs from core and noncore customers annually through the Joint Utilities respective Annual Gas True-Up filings.

35. Within 30 days of the effective date of this decision, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each include in their respective procurement contracts a certification requirement limiting hydrogen sulfide in gathering lines to 10 parts per million.

36. Within 30 days of the effective date of this decision, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each file a Tier 1 Advice Letter updating the Biomethane Incentive Reservation Form to include an agreement to limit hydrogen sulfide in gathering lines to 10 parts per million.

37. Any contract between a project developer and an investor-owned utility shall specify how tipping fees may modify contract terms, if at all. Energy

Division staff shall ensure that each contract meets this requirement prior to approval.

38. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall procure biomethane only from producers that contractually agree that any Class 8 trucks purchased or leased for use in the production of biomethane after the effective date of this decision shall be near-zero emissions (NZE) or zero-emissions (ZE) vehicles. NZE vehicles must comply with California Air Resources Board regulations for ultra-low nitrous oxide vehicles, and any gas-powered vehicles shall exclusively use bio-compressed natural gas rather than fossil gas. Any production facility supplying biomethane to an investor-owned gas utility shall be required to agree to such terms, disclose all Class 8 trucks currently used in its operations, and inform the utility it contracts with whenever a new vehicle is purchased or leased for use at the facility from which the biomethane is being procured. The greenhouse gas reduction and environmental benefit of such vehicles shall be factored in the carbon intensity score. The current or successor proceeding to commence in 2025 shall evaluate when to require prospective purchases or leases of Class 8 trucks to be exclusively ZE.

39. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall procure of biomethane only from production facilities that agree to prospectively cap on-site combustion generation of electricity using their own biogas beyond current generation levels. Any additional electric generation shall either use biomethane or biogas that is partially treated to reduce constituents of concern such as siloxanes and hydrogen sulfide, for use in non-combustion technology

such as an on-site fuel cell stack. This requirement shall be filed in the procurement contract advice letters described in Ordering Paragraph 2.

40. If Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation procure from biomethane production facilities that have yet to purchase or plan and construct electric generation infrastructure at the effective date of this decision, those facilities shall contractually agree to use only non-combustion technologies for any electric generation on-site. This restriction shall be filed in the procurement contract advice letters described in Ordering Paragraph 2.

41. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall prioritize procurement from biomethane projects that use carbon capture and use or storage technology. The greenhouse gas reduction and environmental benefit of carbon capture and storage or use shall be included in the carbon intensity score.

42. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall prioritize procurement from biomethane projects that use waste byproducts, including biosolids, sewage sludge, digestate, and biochar for any greenhouse gas-reducing use rather than putting them in landfills.

43. Southern California Gas Company and Pacific Gas and Electric Company shall each file an application no later than July 1, 2023, proposing at least one woody biomass gasification project focused on conversion of woody biomass to biomethane. These pilot projects shall include the procurement of bio-SNG from forest, agricultural, and urban wood waste pyrolysis and gasification projects using methanation. Each utility may decide whether its pilot project will

focus on forest or agricultural waste based on what best serves its interests and the interests of its customers. Southern California Gas Company and Pacific Gas and Electric Company shall coordinate such gasification projects and strategic placement with the pilot projects authorized for the Department of Conservation by Senate Bill 155. The project cost shall include pipeline extensions to the pilot facilities. Pipeline extensions should facilitate future potential extensions for additional projects and the pilots should propose methods for using carbon dioxide in carbon capture and storage or use projects rather than venting it to the atmosphere. Pilots proposed should test technologies that are capable of expansion and that have significant potential to increase the renewable natural gas supply in the long term. The pilots shall study and report fugitive methane, pollutant, and particulate matter emissions and emissions reduction or elimination methods in the gasification or pyrolysis process, the methanation process, and pipeline infrastructure. The utilities shall set aside $40 million from their 2022 Cap-and-Trade Program allowance auction proceeds to fund these pilot projects.

44. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall within 15 days of the effective date of this decision, each of Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively, Joint Utilities) shall file a Tier 1 Advice Letter revising their natural gas 2022 Climate Credit amount to reflect the reduction mandated by this decision. The Joint Utilities' advice letter filings shall modify the table format established by Decision (D.) 15-10-032 (*i.e.*, Table C of Appendix A of that decision, subsequently modified by D.20-03-027 and then D.20-12-031) to include below line 9c a new subaccount line

numbered 9d and titled "Bio-SNG Pilot Costs." This line shall record each gas utility's share of the one-time $40 million set-aside, as established by this decision as follows:

- SoCalGas: $19,704,000 (49.26 percent of $40 million)
- PG&E: $16,936,000.00 (42.34 percent of $40 million)
- SDG&E: $2,708,000 (6.77 percent of $40 million)
- SWG: $652,000 (1.63 percent of $40 million)

45. Line 10 of Table C of Appendix A of Decision (D.) 15-10-032 shall also be modified to equal the Subtotal Allowance Proceeds minus Outreach and Admin Expenses minus Senate Bill 1477 Compliance Costs minus Renewable Natural Gas Incentive Costs minus Bio-SNG Costs. To reflect this change, the Joint Utilities shall further modify the template for Table C by changing the description of Line 10 of Table C of Appendix A of D.15-10-032 to "Net GHG Proceeds Available for Customer Returns ($) (Line 8 + Line 9 + Line 9b + Line 9c + Line 9d)." This revised table format shall be used in all applicable future filings seeking approval of the natural gas Climate Credit amount for each of the Joint Utilities until or unless the Commission decides otherwise.

46. Within 15 days of the effective date of this decision, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each file a Tier 1 Advice Letter modifying its existing Greenhouse Gas Balancing Accounts (GHGBA) to add a subaccount to track all Cap-and-Trade allowance proceeds set aside pursuant to this decision, as well as any interest accrued on those proceeds. Following the first set-aside deducted from the 2022 Climate Credit, each of the Joint Utilities' annual set-aside shall be deposited in quarterly installments equal to one-quarter of the annual established allocation for each gas investor-owned utility. Those

quarterly installments shall be set aside on or before March 1, June 1, September 1, and December 1 to follow California Air Resources Board's quarterly auctions in February, May, August, and November. Each of the Joint Utilities may delay their first quarterly set-aside from no later than March 1, 2022 to no later than June 1, 2022 to provide adequate time for the filing and approval of the new balancing subaccount.

47. If either San Diego Gas & Electric Company or Southwest Gas Corporation procures biomethane from agricultural waste and urban wood waste pilot projects located in Southern California Gas Company's service territory, they may use their respective shares of allowance proceeds collected pursuant to this decision to offset the pilot project costs. Any of the Joint Utilities may request Commission approval to return unused allowance proceeds to their residential customers in the form of the next Climate Credit if they anticipate those proceeds will not be spent. A gas investor-owned utility wishing to return allowance proceeds to its residential customers shall submit a Tier 2 Advice Letter seeking such approval from the California Public Utilities Commission.

48. Any unspent Cap-and-Trade allowance proceeds shall be returned to ratepayers in the Climate Credit by December 31, 2032 pursuant to Cap-and-Trade Regulation Section 95893 (d)(8).

49. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall require biomethane producers to include a methane leak standard in the Standard Biomethane Procurement Methodology life cycle carbon intensity accounting in the modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model. In the procurement contract, the utilities shall establish a procedure for immediate methane leak remediation at the production

facility or along that gas pipeline interconnection as the preferred response, and specify required actions if there is no immediate remediation, such as timeline for repair, a graduated fee schedule to promote timely repair, or payment reductions, etc.

50. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall maintain exclusive ownership of all environmental attributes from contracted biomethane sources and may not sell, trade, or transfer any of these attributes. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall require biomethane producers to track volumetric injections of biomethane into pipelines through the Midwest Renewable Energy Tracking System (M-RETS) platform or other platform resulting from the workshop in Ordering Paragraph 1 above.

51. Southern California Gas Company and San Diego Gas & Electric Company are authorized to allow all customers that sign up for the Voluntary Renewable Natural Gas Tariff (VRNGT) program to contract for biomethane in addition to Senate Bill 1440 targets. Those costs shall be recovered via the terms of the VRNGT program.

52. The 2018 Low Carbon Fuel Standard pilot arrangement for renewable natural gas fueling is outside the scope of this decision.

53. The Commission will open a ratesetting proceeding to consider distributing above market biomethane procurement costs to noncore customers.

54. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each file a Tier 2 advice letter within 45 days of the effective date of this decision to establish a new balancing account with subaccounts to record above-market

commodity biomethane costs and program administrative costs to support biomethane procurement and pilots. The recovery of the balancing account costs shall be done through their respective Annual Gas True-Up filings.

55. The Office of Governmental Affairs shall work with the Legislature and stakeholders for legislation requiring core transport agents to procure biomethane at the same rate as the Joint Utilities.

56. Biomethane procurement contracts shall be for a maximum of 15 years, with biomethane deliveries not to extend beyond 2040. Contract duration will be revisited in 2025 in either the current or a successor proceeding.

57. Southwest Gas Corporation is authorized to submit a Tier 2 Advice Letter to modify as necessary its Biomethane Gas Plan (BGP) approved in Decision 20-05-003 to distinguish between biomethane purchases made pursuant to its BGP versus those made pursuant to this decision.

58. This proceeding remains open to address the remaining scoped issues.

This order is effective today.

Dated February 24, 2022, at San Francisco, California.

ALICE REYNOLDS
President
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE HOUCK
JOHN R.D. REYNOLDS
Commissioners

Attachment 1:
Glossary of Acronyms

Senate Bill (SB) 1440 Glossary of Acronyms

Bcf	Billion Cubic Feet
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCS	Carbon Capture and Storage
CCUS	Carbon Captures and Use or Storage
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CTA	Core Transport Agent
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
H_2S	Hydrogen Sulfide
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
LCFS	Low Carbon Fuel Standard
MMBtu	Million British Thermal Units
M-RETS	Midwest Renewable Energy Tracking System
MSCF	Thousand Standard Cubic Feet
NZE	Near-Zero Emissions
OSHA	Occupational Safety and Health Administration
RGPP	Renewable Gas Procurement Plan
RPS	Renewables Procurement Standard

SBPM	Standard Biomethane Procurement Methodology
SLCP	Short-Lived Climate Pollutant
SNG	Synthetic Natural Gas
SRGIA	Standard Renewable Gas Interconnection Agreement
SRGIT	Standard Renewable Gas Interconnection Tariff
SRGPM	Standard Renewable Gas Procurement Methodology
VRNGT	Voluntary Renewable Natural Gas Tariff
WWTP	Wastewater Treatment Plant
ZE	Zero Emission

(END OF APPENDIX A)