Decision 15-06-029 June 11, 2015

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 (Filed February 13, 2013)

DECISION REGARDING THE COSTS OF COMPLIANCE WITH DECISION 14-01-034 AND ADOPTION OF BIOMETHANE PROMOTION POLICIES AND PROGRAM

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DECISION REGARDING THE COSTS OF COMPLIANCE WITH DECISION 14-01-034 AND ADOPTION OF BIOMETHANE PROMOTION POLICIES AND PROGRAM

Summary

This decision addresses who should bear the costs of complying with Decision (D.) 14-01-034, and addresses policies and programs which promote the production and distribution of biomethane within California. To ensure health and safety, D.14-01-034 adopted concentration standard limits for constituents of concern that may be found in biomethane, and monitoring, testing, reporting, and recordkeeping requirements. Compliance with such standards and protocols allows a biomethane producer to safely interconnect with, and to inject merchantable biomethane into, the natural gas pipeline system of a utility.

Based on the code sections added and amended by Assembly Bill (AB) 1900, as well as other code sections cited by the parties, today's decision concludes that the costs of complying with the standards and protocols adopted by D.14-01-034 should be borne by the biomethane producers.

However, consistent with AB 1900 and to provide initial support to the developing biomethane market, today's decision adopts a policy and program of a five-year monetary incentive program to encourage biomethane producers to design, construct, and to successfully operate biomethane projects that interconnect with the gas utilities' pipeline systems so as to inject biomethane that can be safely used at an end user's home or business. As described in this decision, each biomethane project that is built over the next five years, or sooner if the program funds are exhausted before that period, can receive 50% of the project's interconnection costs, up to $1.5 million, to help offset these costs upon the successful interconnection and operation of the facility.

1. Background

The Commission opened this Order Instituting Rulemaking (Rulemaking or R.) to address the actions required of the Commission in Assembly Bill (AB) 1900. AB 1900, which was enacted into law in Chapter 602 of the Statutes of 2012, required the Commission to adopt standards that specify the concentration limits that certain constituents found in biomethane must meet before the biomethane is allowed to be injected into the pipeline systems of the natural gas utilities.[1] In addition, AB 1900 required the Commission to adopt monitoring, testing, reporting, and recordkeeping protocols. As a result, the Commission in Decision (D.) 14-01-034 adopted concentration standards for 17 constituents of concern found in biomethane, and adopted certain monitoring, testing, reporting, and recordkeeping protocols that the biomethane producers and gas utilities must comply with. These concentration limits and protocols were adopted to ensure the protection of human health, and the integrity and safety of the pipelines and pipeline facilities.

Pursuant to the May 2, 2013 Scoping Memo and Ruling issued in this proceeding, the cost issues associated with meeting the standards and protocols adopted in D.14-01-034 are to be determined in this phase of the proceeding. The second phase of this proceeding was opened "to consider who should bear the costs of meeting the standards and requirements that the Commission adopted in D.14-01-034." (April 9, 2014 Amended Scoping Memo and Ruling at 3 [Amended Scoping Ruling].)

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[1] AB 1900 made certain changes to the Health and Safety Code, added Public Resources Code § 25326, and added Pub. Util. Code §§ 399.24 and 784.

The Amended Scoping Ruling at 3 to 4 established the schedule for parties "to file comments and reply comments on who should bear the costs of complying with the Commission-adopted testing, monitoring, reporting, and recordkeeping requirements." The Amended Scoping Ruling at 3 directed the parties to "(1) identify the costs that are at issue; and (2) describe the party's reasoning and justification for why the biogas supplier, the biomethane producer or supplier, the gas utility, or other entity or person, should bear that particular cost." The Amended Scoping Ruling at 3 to 4 specifically asked the parties to comment on the following:

1. What costs are associated with the testing, monitoring, reporting, and recordkeeping requirements as adopted by D.14-01-034? Are these one-time or ongoing costs?
2. How do these costs compare to the total start-up and operational costs, as appropriate, of the biogas production facility?
3. Should the biogas supplier, biomethane producer or supplier, the gas utility or other entity or person bear particular costs and why? and
4. Are there any other costs that should be considered, and the reasoning why those particular costs should be resolved by the Commission?

The Amended Scoping Ruling also stated that since this proceeding was categorized as quasi-legislative, and because the issue of who should bear cost responsibility is a policy question to be addressed by the Commission, that no evidentiary hearings would be held to decide this issue. Instead, "the cost issues in this phase of this proceeding will be decided based on the comments and reply comments that are to be filed." (Amended Scoping Ruling at 4.)

Opening comments were filed by the following: Bioenergy Association of California (BAC) and the California Association of Sanitation Agencies (CASA); Coalition for Renewable Natural Gas (CRNG); Green Power Institute (GPI);

Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E);[2] Southwest Gas Corporation (Southwest Gas); and Waste Management (WM).[3]

Reply comments were filed by the following: BAC and CASA; CRNG; Consumer Federation of California (CFC); ORA; PG&E; Southern California Edison Company (SCE); SoCalGas and SDG&E; Southern California Generation Coalition (SCGC); Southwest Gas; and WM.

All of these opening and reply comments have been reviewed and considered in formulating today's decision.

2. Description of the Costs and the Positions of the Parties

2.1. Introduction

This phase of the proceeding addresses who should pay for the costs of complying with D.14-01-034, and the "policies and programs" that can be used to "promote the in-state production and distribution of biomethane." (Pub. Util. Code § 399.24.[4])

The following are summaries of the types of costs that one is likely to encounter in the development and operation of a biomethane project, and the positions of the different parties on who should bear these costs and how the allocation of these costs should be implemented. The arguments as to who

[2] SoCalGas and SDG&E are sometimes referred to in this decision as Sempra.

[3] In this decision, we sometimes refer to BAC, CASA, CRNG, GPI, and WM as the biomethane proponents.

[4] Unless otherwise stated, all code section references are to the Public Utilities Code.

should pay for the biomethane-related costs center primarily around AB 1900's addition of § 399.24.[5] That code section provides as follows:

> (a) To meet the energy and transportation needs of the state, the commission shall adopt policies and programs that promote the in-state production and distribution of biomethane. The policies and programs shall facilitate the development of a variety of sources of in-state biomethane.
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> (b) For the purposes of this section, "biomethane" means 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]

2.2. Types of Costs

There are three types of costs that one is likely to encounter in developing and operating a biomethane project in California. These costs consist of the following: (1) the pre-injection costs incurred prior to the injection of biomethane into the utility pipeline; (2) the interconnection costs incurred in order to interconnect the biomethane facility with the utility pipeline; and (3) the post-injection ongoing costs of maintaining and operating the biomethane facility and the pipeline access.

2.2.1. Pre-Injection Costs

The pre-injection costs include costs related to the development of the biomethane receipt point facility, the cost of upgrading the biogas to biomethane, the cost of testing the biomethane, and the cost of the monitoring, testing,

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[5] As discussed later in this decision, some of the biomethane proponents also cite to §§ 740.3 and 740.8 as justification for why the utility ratepayers should pay for the biomethane-related costs.

[6] In D.14-01-034, the Commission addressed and adopted the standards and requirements referenced in Health and Safety Code § 25421. As stated in the Amended Scoping Memo, the standards and requirements adopted in D.14-01-034 are not being revisited in this proceeding.

reporting, and recordkeeping systems. Such costs include one-time pre-injection testing and start-up costs. According to PG&E, the receipt point start-up costs will "include project development and construction, pipeline tap, measurement and gas quality equipment, valving and piping, communications and [supervisory, control and data acquisition equipment] SCADA, electrical ground, and road access."[7] (PG&E Opening Comments at 4.) Other one-time administrative costs "include computer modelling, nominations system upgrades, and creation of therm billing zones." (*Ibid*.)

Depending on whether the biomethane needs to be blended to meet the heating value standard, there will be one-time costs associated with the planning, design, and construction of the infrastructure needed for blending. BAC and CASA note that the costs associated with the blending of biomethane to meet the heating value standard are likely to be substantial or cost-prohibitive. CRNG estimates that the cost to build a blending system could range between $330,000 and $660,000.

Excluding interconnection costs, WM estimates that the capital costs of a facility designed to meet a 990 British thermal units per standard cubic feet heating value standard will cost from $27,400,000 to $33,100,000.[8] For the annual operating costs, WM estimates a range of $2.5 million to $3.1 million which excludes the costs of testing and recordkeeping.

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[7] After the receipt point is constructed, PG&E notes that the utility then takes over ownership of the facility. The ongoing operating and maintenance associated with the receipt point will be performed by the utility, but such costs will be billed back to the biomethane producer.

[8] WM also points out that a biomethane developer will need assurances from the utility about the quality and composition of the natural gas supplied by the utility to the biomethane producer for blending purposes.

PG&E points out that a tax issue may arise if PG&E supplies the gas that is used for the upstream blending of the biomethane to meet the heating value standard. PG&E contends that the Commission's policy is if a Contribution-In-Aid-Of-Construction (CIAC) tax is incurred and a gross-up is not collected by the utility, that the tax risk falls on utility shareholders, instead of on customers. To prevent this, PG&E states that it "must require a gross-up to be paid in advance in these transactions… unless the supplier first obtains a positive ruling from the [Internal Revenue Service] IRS that no tax is incurred." (PG&E Opening Comments at 10.) PG&E contends that the CIAC issue should be considered in this phase because the gross-up "may represent a substantial percentage of the overall project start-up cost depending on annual revision of the tax rate by federal and state tax authorities." (*Ibid.*)

2.2.2. Interconnection Costs

Interconnection costs consist of the necessary studies, permitting and regulatory, land, design and construction, and equipment and materials, to connect the biomethane receipt point facility to the utility pipeline, and to meter the gas flow. These include the interconnection costs described in PG&E's Rule No. 21, SDG&E's Rule 39, and SoCalGas' Rule No. 39. The biomethane proponents contend that the costs of interconnection and the other costs associated with biomethane are significantly higher in California than elsewhere, due in part to the standards and requirements adopted in D.14-01-034.

According to CRNG, its members have been given estimates by the gas utilities that these interconnection costs could range from $1.5 million to $3 million, depending on the landfill's location (rural or urban), and the project's proximity to the utility's pipeline. CRNG contends that these "estimates are exceptionally high when compared to the cost of pipeline interconnect outside of

California," which have ranged in cost from $75,000 to a high of $500,000. (CRNG Opening Comments at 5.) CRNG is concerned that the interconnection costs "between the biogas facility and the common carrier pipeline could equal and even exceed the total costs of developing the actual biogas facility." (CRNG Opening Brief at 7.)

For a point of receipt facility, Sempra estimates that the cost will depend on facility size and output, and that the costs could range from $1.2 million to $1.9 million. For the monthly operational costs of such a facility, Sempra estimates it will cost about $3,500 per month.

2.2.3. Post-Injection Costs

The third type of costs are post-injection costs. These post-injection costs are the ongoing costs of equipment, odorants, and labor costs needed to comply with the routine operating costs associated with the testing and monitoring requirements for some or all of the 17 biomethane constituents, as well as operations and maintenance expenses associated with the receipt point facility.

These post-injection costs could also include the cost of blending. If the blending process requires the use of propane to elevate the heating value of the biomethane, CRNG contends that the propane cost will add at least an additional $262,262 per year. In addition, a Project Safety Management permit would be needed for the propane, which will result in a one-time cost of about $150,000 and ongoing compliance costs of about $30,000 per year.

According to Sempra, the ongoing costs will vary depending on the source of the biomethane, and the biomethane producer's compliance with the gas delivery specifications. Regarding the costs in general of a biomethane project, the utilities contend that there are a number of factors that will affect the variability of the start-up and operational costs of such projects. These factors include: the source of the biogas (e.g., dairy, wastewater treatment, landfill); the proximity of the biogas production facility to the gas transmission system; and the facilities necessary to process, test, and monitor the biogas to ensure that the injected biomethane meets the gas interchangeability requirements set forth in the utilities' tariffs. PG&E also notes that it will incur a variety of costs to monitor the gas quality results, to detect possible corrosion, and to establish and monitor contractual relationships with biomethane suppliers.

For the post-injection costs, CRNG estimates that these ongoing costs will be a least $7,610 per month or about $91,312 per year.

BAC and CASA contend that the costs associated with the testing and monitoring of biomethane is difficult to ascertain because the standards and requirements adopted in D.14-01-034 are so stringent and unprecedented, and because no one wants to share specific cost data due to competitive reasons. Based on other biogas upgrading systems in operation, BAC and CASA contend that the capital expenses for biomethane projects in California can be expected to cost 30 to 50 % more, and that operating expenses will cost up to 30 % more.

Sempra estimates that the ongoing annual testing costs may range from about $6,250 to $25,000 depending on the frequency of testing.

2.3. Positions of the Parties

There are basically two schools of thought as to how the costs of a biomethane project should be allocated. In addition, some of the biomethane proponents and the utilities propose, as described below, that the revenues from the sale of the natural gas cap and trade allowances be used to fund the costs of biomethane production.[9]

2.3.1. Positions of the Biomethane Proponents

The first school of thought as to how costs should be allocated is the one favored by the biomethane proponents. This theory proposes that most or all of the costs of complying with the standards and protocols adopted in D.14-01-034 be borne by the utility ratepayers.

For example, some of the biomethane proponents recommend that the biomethane producers bear the routine costs of testing, monitoring, conditioning and recordkeeping. However, some of these biomethane proponents recommend that the incremental costs of injecting biomethane, i.e., "those costs that are in addition to or greater than the costs of fossil fuel gas injection" be borne by utility ratepayers. (BAC and CASA Reply Comments at 4; see GPI Opening Comments at 3.)

CRNG recommends that the costs of the biomethane production facility be borne by the biomethane developer. CRNG agrees with BAC and CASA that since the testing of the additional constituents set forth in D.14-01-034 will benefit "human health and safety and pipeline safety and integrity," that the post-injection "costs associated with testing, including the costs of monitoring systems and equipment, should appropriately be borne by the ratepayer." (CRNG Reply Comments at 5.)

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[9] Our reference to "cap and trade" refers to the California Greenhouse Gas Cap-and-Trade Program, which is found in Title 17 of the California Code of Regulations beginning at § 95801 and following. The cap and trade program is administered by the California Air Resources Board (ARB).

WM's position differs from some of the other biomethane proponents. WM recommends that the incremental costs of complying with the constituents of concern and pipeline integrity standards that exceed what is required of fossil fuel producers, be shared equally between the biomethane producer and the utility.

BAC and CASA recommend that the utilities bear the costs of interconnection, and that the utilities standardize the "interconnection costs so that they are more predictable from project to project, depending on the amount of gas, interconnection distance and other variables." (BAC and CASA Opening Comments at 9-10.)

CRNG recommends that the interconnection costs be borne by the gas utility ratepayers because the gas utilities will take ownership of the interconnection facilities once they are developed. Since "a significant portion of the Receipt Point facility will be constructed to benefit the utility and its ratepayer," CRNG contends that the utility ratepayers should bear these interconnection costs. (CRNG Reply Comments at 13.) WM also recommends that the interconnection costs be borne by the utility, or that such costs be reduced by using the revenues generated by the cap and trade allowances.

The biomethane proponents provide several reasons as to why they believe it is appropriate to shift all or most of the costs of complying with D.14-01-034 on utility ratepayers.

The first reason is based on the language of § 399.24, where the statute refers to the Commission "shall adopt policies and programs that promote the in-state production and distribution of biomethane." BAC and CASA contend that the costs of the standards adopted in D.14-01-034 must be allocated in a way that ensures the promotion of biomethane, rather than to discourage its development. BAC and CASA contend that to do otherwise will make it cost prohibitive for biomethane developers to inject compliant gas into the utilities' gas pipeline systems.

GPI acknowledges that "the cost of biomethane supplies will undoubtedly exceed those of conventional sources." (GPI Opening Comments at 1.) GPI is concerned "that if all of the D.14-01-034 compliance costs are apportioned to the biomethane suppliers, it will make the cost of biomethane look even higher than it otherwise is relative to the cost of conventional gas supplies, and this perception, once created, could make it that much more difficult to successfully achieve the goals of AB 1900." (GPI Opening Comments at 2.) To avoid this perception, GPI contends "it is important to try to avoid inflating the cost of renewable energy by loading it up with costs that conventional supplies are not burdened with." (*Ibid*.)

The second reason some parties contend as to why costs should be shifted to utility ratepayers is because of the public benefits that biomethane confers upon the users of biomethane. This argument is tied to the compliance obligations in the Global Warming Solutions Act of 2006 contained in AB 32 and enacted into law in Chapter 488 of the Statutes of 2006, and the language contained in §§ 740.3 and 740.8.

BAC and CASA state that "biomethane is probably one of the best and most cost-effective means for the utilities to meet their AB 32 compliance obligations." (BAC and CASA Opening Comments at 5.) WM contends that California policy and law make it clear that the "development and use of biomethane is an essential means of meeting the state's Renewable[s] Portfolio Standard (RPS), greenhouse gas (GHG) reduction programs (AB 32), and the

Low Carbon Fuel Standard (LCFS), enacted to protect our citizens and our environment."[10] (WM Opening Comments at 4.)

BAC and CASA point out that the biomethane can be used to reduce emissions by using biomethane as a lower carbon transportation fuel instead of fossil fuel gas. BAC and CASA contend that to the extent "biomethane is used to help the utilities and their large emitting customers comply with AB 32, the utilities and their ratepayers should pay the costs of pipeline biomethane, as they would pay any other regulatory compliance costs." (BAC and CASA Opening Comments at 7.) BAC and CASA contend that failing to allocate these costs in this manner will impede the development of biomethane, which is contrary to the intent of AB 1900.

CRNG contends that §§ 740.3 and 740.8 "make specific provision for ratepayer cost adoption in the case of activities that ensure increased use of alternative fuels." (CRNG Opening Comments at 20.) CRNG, BAC and CASA contend that the costs should be allocated to utility ratepayers because the ratepayers' "interests," as defined in § 740.8, and as recognized in the joint report that was submitted in this proceeding by the ARB and the Office of Environmental Health Hazard Assessment, include "safer, more reliable" gas service, and activities that reduce "health and environmental impacts from air pollution, and greenhouse gas emissions related to electricity and natural gas production and use, and increased use of alternative fuels."[11] (See CRNG Reply

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[10] The RPS history originated in Chapter 516 of the Statutes of 2002, followed by Chapter 464 of the Statutes of 2006, and Chapter 1 of the Statutes of 2011 Extraordinary Session. The history of the LCFS is found in AB 32, and the Governor's Executive Order S-01-07.

[11] An alternative argument of BAC and CASA, which WM has proposed, is for the Commission to allocate the incremental costs of biomethane to both ratepayers and developers. BAC and CASA contend, however, that this alternative proposal "will do much less to promote

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Comments at 9-10; BAC and CASA Reply Comments at 3.) CRNG contends that because D.14-01-034 adopted standards and protocols for human health and safety, and pipeline and pipeline facility safety and integrity, that these "regulatory requirements cannot be divorced from the costs of bringing non-fossil renewable resources to market." (CRNG Opening Comments at 21.)

The third reason that some of the biomethane proponents make as to why certain costs, such as interconnection costs, should be borne by utility ratepayers is because the Commission has allowed similar cost-shifting in the past. Some of the biomethane proponents point out that cost-shifting has occurred with respect to the cost of installing the transmission lines needed to access electricity from renewable generators. They note that in the Sunrise Powerlink Transmission Project (D.08-12-058), the Tehachapi Renewable Transmission Project (D.09-12-044), and the Colorado River Substation Project (D.11-07-011), the Commission recognized the public benefit of these projects, and assigned these interconnection costs to the electric utilities' ratepayers. CRNG recommends that the Commission follow precedent, and states "it is appropriate for the Commission to rule that ratepayers bear the costs of biomethane's interconnection to a gas transportation line, including costs for the pipeline extension" that "goes from the outlet of the point of receipt to the nearest pipeline that can accept the volume of biomethane and transport it pursuant to the applicable backbone transportation service agreement." (CRNG Reply Comments at 14.) In the event the Commission does not adopt CRNG's contention that utility ratepayers should bear all of the interconnection costs,

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biomethane development and distribution than if all incremental costs of pipeline biomethane are borne by ratepayers…." (BAC and CASA Reply Comments at 5.)

CRNG contends "that the ratepayers should bear the costs of the interconnect pipeline for no less than the first three miles as part of the overall interconnection costs," and "that the ratepayer and biomethane producer split the costs of pipeline extension beyond three miles." (CRNG Reply Comments at 5 and 15.) WM contends that allocating the interconnection costs in this manner is appropriate because the injection of biomethane into the utility pipeline will allow the utilities to avoid the higher cap and trade compliance costs. In addition, WM contends that the utility ratepayers will benefit through "a more diverse and competitive energy supply, cleaner energy, lower greenhouse gas emissions to the atmosphere, better overall air quality, and a more secure energy supply." (WM Opening Comments at 18.)

BAC and CASA oppose the recommendations of the utilities and ORA to assign all of the costs of biomethane to the biomethane producers. BAC and CASA contend that to do so will defeat the purpose of AB 1900 to promote in-state biomethane production. Similarly, CRNG contends that without "a favorable ruling regarding cost responsibility and allocation in this phase," that the regulations adopted in D.14-01-034 could "jeopardize the development of biomethane projects in California." (CRNG Reply Comments at 9.) For those reasons, CRNG requests that the Commission "consider appropriate cost-shifting." (CRNG Opening Comments at 21.) WM contends that the costs imposed by D.14-01-034 "create a potentially impossible hurdle for producers to overcome and therefore create a de facto barrier to entry if the cost burden is placed totally on biomethane suppliers." (WM Opening Comments at 3.)

2.3.2. Positions of the Utilities and End Users

The second school of thought as to how costs should be allocated is the position favored by some of the utilities and the advocates on behalf of end users.

They contend that all of the costs of developing, interconnecting, and operating a biomethane project should be borne by the biomethane developer.[12]

The utilities and ORA take the position that since the current gas suppliers bear all of the costs relating to interconnection, testing, and gas conditioning, the same cost allocation rule should apply to the biomethane producers.

Although ORA acknowledges the societal benefits of promoting the use of biomethane, ORA recommends that the costs of producing biomethane should be the exclusive responsibility of the biomethane producers. ORA contends that this will create a level playing field for both fossil gas producers and biogas producers. SCE contends that the existing cost allocation rule will ensure fair open access to all gas suppliers on a non-discriminatory basis, and reflect the true cost of the biomethane as compared to other renewable projects.

ORA recognizes the biomethane proponents have made a case that the cost of developing a biomethane project in California will be much higher than developing a similar project in other states. However, ORA contends that the biomethane proponents' arguments ignore the fact that California customers have carbon incentives to pay a premium for biomethane supplies. ORA notes that cap and trade, RPS, and the LCFS, are all examples of California putting a price on carbon. ORA contends that the price premium for using biomethane will allow a biomethane producer to earn an appropriate return on its investment.

SCGC agrees with the utilities and ORA that the biomethane producers should bear all of the gas production costs, including the cost of interconnecting

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[12] Alternatively, some of these parties recommend that the revenues from the sale of the cap and trade allowances could be used to cover some or all of the biomethane project costs.

with a gas utility's system. SCGC cautions that if the biomethane producers' costs are allowed to be shifted onto utility ratepayers, that this will encourage other gas producers to do the same.

SCE contends that if the costs of interconnection are shifted onto utility ratepayers, that this would be discriminatory and violate § 784 because non-biomethane gas producers and biomethane gas producers will be treated differently. SCE contends that if the biomethane producers are given preferential cost treatment, that this will skew "the price signals to advantage one source of 'clean' energy over another and will have the undesirable effect of increasing costs without achieving real environmental benefit." (SCE Reply Comments at 3.) In addition, SCE contends that such treatment will encourage economically inefficient interconnections because such projects will not be paying their true costs of connection.

CFC contends that the promotion of biomethane production should not be encouraged by shifting the biomethane producers' costs onto the utility ratepayers. Instead, CFC contends that the support and promotion of biomethane be encouraged by eliminating the barriers to market entry, and preventing discriminatory access.

CFC contends that § 740.3 addresses the development of infrastructure to facilitate the use of electricity and natural gas to fuel low emission vehicles. CFC contends this proceeding is not addressing the fueling of low emission vehicles, but instead is addressing the requirements that biomethane producers must meet in order to protect ratepayers and the existing infrastructure.

In response to the comment of BAC and CASA that the utilities should standardize the interconnection costs, Sempra notes that BAC and CASA did not explain how such standardization could occur, and that standardization is not possible for all interconnections because of the variability of each project.

If the Commission decides to adopt the cost allocation proposals of the biomethane proponents to shift costs to the utility, Sempra contends the Commission needs to make clear in this decision that such costs are to be allocated into rates, and such costs provide environmental benefits to ratepayers and society as a whole.

2.3.3. Use of Cap and Trade Revenues

Some of the biomethane proponents and the utilities recommend that the revenues from the sale of investor-owned utility cap and trade allowances be used to offset the biomethane production costs. WM, Sempra, and some of the other parties recommend that the Commission should make a determination in this proceeding that the revenues from the cap and trade allowances be used "to defray the cost of biomethane development and operation." (WM Opening Comments at 16.) Sempra recommends that the Commission make a finding in this proceeding "that the use of revenue set aside for clean energy projects may be used to promote biomethane injection." (Sempra Opening Comments at 9.) Sempra contends that such a finding will allow the utilities to propose programs to use the cap and trade revenues to support biomethane injection. Sempra states that such revenues "could be allocated to pay a portion of the point of receipt facilities, pay the incremental costs incurred by biomethane interconnectors, or fund an incentive program to support biomethane injection more generally." (Sempra Opening Comments at 9-10.) Sempra suggests that this proceeding, and R.14-03-003, should lead "to separate utility applications proposing how to use cap and trade allowance revenues to support biomethane injection." (Sempra Reply Comments at 5.)

SCGC, BAC, and CASA support Sempra's recommendation that a finding be made in this proceeding about the use of these revenues. SCGC contends that such a determination will "facilitate making a proposal in another proceeding to use gas utility cap and trade auction revenues to promote the development of biomethane by offsetting the cost of meeting the standards and requirements adopted in D.14-01-034."

Some of the biomethane proponents contend it is appropriate to use the cap and trade revenues because the injection of low carbon biomethane into the gas pipeline system will reduce GHGs and other environmental impacts, which in turn will lower the cost of compliance with the GHG gas regulations by the utilities. SCGC points out that in D.12-12-033, the Commission determined that an electric utility's cap and trade revenues can be used for energy efficiency or clean energy programs or projects that have a stated goal of reducing GHG emissions.

WM recommends that the Commission "consider a fair sharing of cost between the biomethane supplier and generator, utilities and their rate base, and use of revenues from the sale of GHG credits provided to natural gas suppliers." (WM Opening Comments at 5.) WM contends that such an allocation of costs will meet the goal of AB 1900.

Although WM supports using the cap and trade allowance revenues to promote biomethane, WM is against giving the utilities the right to determine the allocation of such revenues. WM recommends that the Commission "affirmatively and directly allocate a percentage of allowance revenues into a fund for biomethane projects and award grants based on a project's ability to reduce [carbon dioxide] emissions or their equivalent attributable to the natural gas sector." (WM Reply Comments at 8.) WM contends that this will create a "direct and transparent nexus between the use of allowance revenue proceeds and the reduction of greenhouse gas emissions into our atmosphere." (*Ibid*.)

CRNG and Sempra point out that the natural gas utility cap and trade rules are currently being developed, and therefore the use of such cap and trade revenues may not be immediately available.

ORA contends that California already has in place "market based solutions to pricing carbon which should have the effect of making biomethane production more economical over time, without requiring the active intervention of the Commission on behalf of biomethane producers prior to the introduction of gas to the transportation system." (ORA Opening Brief at 3.) ORA further contends that this proceeding should not address issues related to promoting or subsidizing biomethane because AB 1900 does not require the Commission to provide ratepayer subsidies for biomethane production in this proceeding, or to change the current policy as to who should pay for the costs of conditioning gas in order to meet the required standards imposed by D.14-01-034.

On the linkage of this proceeding to other proceedings examining similar kinds of issues, some of the parties contend that this proceeding should not be linked to R.14-03-003, R.11-05-005, and R.11-03-012. Others take the position that this proceeding should be linked to one or more of the other proceedings. ORA believes that the biomethane promotion issues should be addressed in R.11-05-005 so that the biomethane issues can be considered along with other renewable resources.

2.3.4. Tracking of Costs

To carry out the allocation of the costs associated with the biomethane developers' compliance with D.14-01-034, PG&E, Sempra and Southwest Gas request that they be authorized to establish accounts to track these costs.

PG&E "requests Commission approval to establish a new two-way balancing account to record and recover costs and revenue requirements resulting from either the implementation of D.14-01-034 or the development of biomethane projects where costs are not otherwise recovered." (PG&E Opening Comments at 10.) Southwest Gas also requests that it be authorized to establish a balancing account, and that the Commission should make clear in this proceeding that the "costs that are not allocated to the biomethane suppliers will be included in rates." (Southwest Gas Reply Comments at 2.)

Sempra requests that they be allowed to establish memorandum accounts to "allow biomethane producers to begin developing biomethane injection projects with greater certainty concerning costs and avoid direct cost allocation to ratepayers by earmarking a certain portion of cap and trade allowance revenue for the recovery of biomethane interconnection costs." (Sempra Reply Comments at 6.) Sempra recommends that in the event the Commission determines in R.14-03-003 that the cap and trade revenues should not be used in that manner, the utility should be allowed to recover the previously tracked costs in rates.

WM does not object to the request of PG&E and Southwest Gas to establish memorandum accounts to reimburse the utilities for their added expenses. WM points out, however, that these added expenses are to include the "cost of interconnection, the cost of biomethane development in excess of the cost associated with a similarly rated fossil fuel facility, and added operational costs including testing, monitoring and recordkeeping." (WM Reply Comments at 7.)

3. Discussion

The focus of this phase of the proceeding is to consider how the costs associated with the development and operations of the biomethane projects that interconnect with the natural gas utilities' pipeline systems should be allocated, and whether additional policies to promote the use of biomethane should be adopted. As stated in the May 2, 2013 Scoping Memo and Ruling at 2:

> The Rulemaking, and the parties to the Rulemaking, have raised the issue of the cost of implementing the standards and requirements that the Commission will be adopting, and who should pay for the costs of these standards and requirements. This cost issue also involves whether the biomethane producers should have to absorb the costs of meeting the Commission-adopted standards or requirements, or whether there should be policy considerations, such as a subsidy to promote biomethane, that might shift some or all of these costs to customers of the gas utilities.

The Amended Scoping Ruling at 3 stated that this cost phase of the proceeding is "to consider who should bear the costs of meeting the standards and requirements that the Commission adopted in D.14-01-034." As described earlier, we allowed the parties to file comments on who should bear the costs of complying with these constituent limits and the testing-related protocols.

The Commission adopted the constituent limits, and the monitoring, testing, reporting, and recordkeeping protocols in D.14-01-034. The purpose behind those adopted standards and protocols is to ensure that the biogas can be treated and conditioned into merchantable biomethane that can be safely injected into the utilities' pipeline systems and used by customers.

Due to the adopted limits on certain constituents found in biomethane, and the adopted protocols, the biomethane producers will be faced with certain project costs if they want to inject their biomethane into the utilities' gas pipeline systems. These costs are in addition to the other interconnection and projects costs that all gas suppliers must meet in order to interconnect with the utilities' gas pipeline systems.

The key in deciding who should bear the costs of complying with the standards and protocols adopted in D.14-01-034 is § 399.24. Section 399.24 provides that the Commission "shall adopt policies and programs that promote the in-state production and distribution of biomethane," and that "such policies and programs shall facilitate the development of a variety of sources of in-state biomethane."

It is clear that § 399.24 and AB 1900 do not specifically address who should be responsible for the costs of complying with the standards and protocols adopted in D.14-01-034. AB 1900 did not add or amend any code sections to require the Commission to allocate the compliance costs of D.14-01-034 onto a particular group or entity. Instead, § 399.24 merely talks about the adoption of policies and programs to promote the use of biomethane.

Some of the biomethane proponents contend that since the Commission allocated electric transmission costs, which access renewable sources of electricity, onto electricity utility customers, that the Commission should impose a similar type of allocation for biomethane. That is, they contend that the biomethane producers' costs of complying with D.14-01-034 should be passed onto gas utility customers. We are not persuaded, however, that such a result is warranted. Section 784 specifically provides that "the commission shall adopt pipeline access rules that ensure that each gas corporation provides <u>nondiscriminatory</u> open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the delivery of gas." (Emphasis added.) This suggests that the allocation of the costs of interconnection should remain the same for both biomethane producers and traditional natural gas suppliers.

Some of the biomethane proponents also contend that §§ 740.3 and 740.8 should be interpreted to mean that the compliance costs associated with D.14-01-034 should be passed onto utility ratepayers. The biomethane proponents contend that these costs should be passed onto ratepayers because it serves the ratepayers' interests of increasing the use of alternative fuels, and reduces the health and environmental impacts from air pollution and GHG emissions.

However, these code sections are not applicable because § 740.3 focuses on the promotion "of equipment and infrastructure needed to facilitate the use of electric power and natural gas to fuel low-emission vehicles." (Emphasis added.) AB 1900's focus is on the development of biomethane for injection into natural gas pipelines. In this regard, there are multiple end-use purposes of the biomethane, beyond the exclusive use for low-emission vehicles. Therefore, the pass through of costs as contemplated in § 740.3(c), is not relevant to this proceeding. Furthermore, § 740.3(c) states that costs related to the development of infrastructure or equipment needed for electric-powered and natural gas-fueled low-emission vehicles cannot be "passed through to electric or gas ratepayers unless the commission finds and determines that those programs are in the ratepayers' interest." The term ratepayer "interests" is defined in § 740.8 to "mean direct benefits that are specific to ratepayers in the form of safer, more reliable, or less costly gas or electrical service, consistent with Section 451, and activities that benefit ratepayers and that promote energy efficiency, reduction of health and environmental impacts from air pollution, and greenhouse gas emissions related to electricity and natural gas production and use, and increased use of alternative fuels." While some general argument has been proposed by biomethane proponents to the environmental benefits of biomethane, § 740.8 is in direct reference to § 740.3(c), which, again, is specific to low-emission vehicles. Thus, the definition of ratepayer "interests" in this context is not applicable, and therefore § 740.3 does not apply to the cost of complying with D.14-01-034.

There is no specific directive in AB 1900 that directs the Commission to allocate these compliance costs to someone other than the biomethane producers. Instead, the two code sections in AB 1900 that allude to costs are found in: (1) Public Resources Code § 25326 which refers to "impediments;"[13] and (2) § 399.24 which refers to "policies and programs" that promote and facilitate the development of biomethane.

The Energy Commission is looking into the impediments that limit procurement of biomethane in California. As the biomethane proponents point out, the cost of constructing and operating the equipment needed to treat and condition the biomethane in order to meet the standards and protocols in D.14-01-034 are financial obstacles that may limit the use of biomethane. Both AB 1900 and D.14-01-034 describe the health and safety reasons as to why biogas must be treated and conditioned to meet the standards and protocols adopted in D.14-01-034. The conditioning costs for biomethane may be higher than the conditioning costs for conventional natural gas, which may limit the procurement and distribution of biomethane in California.

As directed by § 399.24, and as discussed below, the Commission through today's decision is adopting a policy and program to promote and facilitate the

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[13] Public Resources Code § 25326 states in part that the Energy Commission "shall hold public hearings to identify impediments that limit procurement of biomethane in California, including, but not limited to, impediments to interconnection," and that it "shall offer solutions to those impediments as part of the integrated energy policy report…."

development of biomethane, in addition to the programs already adopted by the Commission that encourage the use of biomethane.

Since the Legislature intended in AB 1900 that there be nondiscriminatory open access to the utilities' gas pipeline systems, and because the Legislature intended that the Commission adopt biomethane standards to ensure the protection of human health, and pipeline and pipeline facility integrity and safety, we conclude that the cost of complying with D.14-01-034 is to be borne by the biomethane producers. (See Health & Safety Code § 25421(c); Pub. Util. Code § 784.)

This conclusion is based on our analysis of the code sections added by AB 1900 as discussed above. In addition, our conclusion that the biomethane producers should bear these compliance costs is consistent with how other natural gas producers who interconnect to the utilities' pipeline systems are treated. These natural gas producers are responsible for their own costs of conditioning their gas to meet the gas interchangeability specifications. To allocate some or all of the costs of complying with D.14-01-034 onto the utility and its shareholders would be discriminatory, and in violation of § 784. The higher cost of treating and conditioning biogas to convert it into merchantable biomethane is simply part of the inherent composition of the biogas itself, and does not discriminate nor prevent the biomethane producers from gaining access to the utilities' pipeline systems. (See D.14-01-034 at 132-133.) If we undertake to shift the costs of complying with D.14-01-034 onto the utility ratepayers, that would provide an advantage to the biomethane producers in the gas marketplace, and result in an uneven playing field.

For all of the above reasons, we conclude that the cost of complying with the standards and protocols adopted in D.14-01-034 is to be borne by the biomethane producer.

Consistent with this approach, we agree with PG&E that the biomethane producer must pay a gross-up for the CIAC tax that may be imposed if a utility supplies the natural gas used for upstream blending of the biomethane. This gross-up can be avoided if the biomethane producer is able to obtain an IRS ruling that no tax will be incurred in such a situation.

Although we conclude that the biomethane producers must bear the cost of complying with D.14-01-034, today's decision adopts, pursuant to § 399.24, a policy and a program to "promote the in-state production and distribution of biomethane," and to "facilitate the development of a variety of sources of in-state biomethane."

Originally, we were reluctant to consider cost subsidies or biomethane promotion issues in this phase of the proceeding. (See D.14-01-034, at 136.) The language of § 399.24 states, in part, that "the commission shall adopt policies and programs that promote the in-state production and distribution of biomethane." (Emphasis added.)[14] This section of the code is specific to the RPS program and is separate from other mandates in AB 1900 to the Commission, codified in § 784. (See Article 16 of Chapter 2.3 in Part 1, Division 1 of the Pub. Util. Code.) In the RPS proceeding (R.11-05-005), a bioenergy feed-in tariff is being developed for projects that use resources such as biomethane to generate electricity. This is one way in which the Commission is already adopting policies and programs to support biomethane.

[14] The use of the word "shall" in § 399.24 is defined in § 14 to mean "mandatory."

However, we are persuaded that the Commission may take steps in this phase of the proceeding to further fulfill the intent of AB 1900. As described below, this will consist of adopting a policy and program of providing monetary incentive to encourage potential biomethane producers to build and operate biomethane projects within California that interconnect with the utilities. Such an incentive will encourage biomethane producers to develop, construct, and operate such biomethane projects. At the same time, this incentive program will help offset the biomethane producers' costs of complying with D.14-01-034, while limiting the financial exposure of the utility ratepayers for such a program.

This monetary incentive program is a variation of the recommendations of some of the biomethane proponents that utility ratepayers should bear some or all of the costs of interconnection. This incentive program shall be structured as follows. The monetary incentive program shall be in effect for a period of five years from the effective date of this decision, and shall terminate as described in this decision. A biomethane project in California that successfully complies with the gas specifications set forth in a gas utility's tariff, including compliance with the standards and protocols adopted in D.14-01-034, and which successfully interconnects with the utility's pipeline system and remains in operation for a minimum of 30 days, with a flow each day for each of those 30 days, shall be entitled to a one-time payment of 50% of the interconnection costs incurred by the biomethane producer, up to a total payment of $1.5 million. This incentive payment shall be credited to the biomethane producer by the gas utility interconnected to this project within 60 days following this 30-day operational period. This utility shall be allowed to recover this incentive amount credit of up to $1.5 million from all of its gas customers on an equal cents per therm basis, with interest.

As noted by some of the parties, these interconnection costs are likely to make up a large part of the overall costs of a biomethane project. These interconnection costs are estimated to cost between $1.2 million to $3 million. This policy and program of helping to offset 50% of these interconnection costs, up to the $1.5 million limit amount, will incentivize potential biomethane producers to decide if such biomethane projects should be built, and whether such projects are economically feasible in light of current natural gas prices.

In order to specify which costs incurred by the developer of the biomethane project are eligible for the monetary incentive program, and to describe the program mechanics related to the distribution of funds to the developer, the utilities shall jointly fill a Tier 2 Advice Letter to modify each of their existing interconnection tariffs. This Advice Letter shall set forth a description of the types of costs that qualify as interconnection costs under the monetary incentive program. In addition, the Advice Letter shall specify the process for determining if a facility has met the 30-day operational requirement, and the process for the distribution of the incentive payment. The Energy Division has discretion over the content and disposition of the Advice Letter and may elect to hold an informal workshop on the utilities' proposal in this Advice Letter before approving or rejecting this Advice Letter filing.

The total statewide monetary incentives available for this program shall be capped at $40 million over the five-year duration of this program. If the $40 million in incentives is exhausted before the expiration of the five-year period, this program shall terminate. If there are funds remaining at the time of program termination, then biomethane projects that have started to inject merchantable biomethane into the utility's pipeline system as of the termination date of this program are eligible for an incentive payment if they otherwise meet the program criteria. For example, if a project begins to inject merchantable gas on the day of program termination, continues to inject for 30 days, and meets all other program criteria, then the project is eligible for an incentive payment.

To keep track of how much in program funds is available for qualifying biomethane projects, each utility that will be interconnecting with such a project shall notify the Director of the Energy Division in a letter, at least 90 days prior to the anticipated interconnection date, of the name, developer, and location of the biomethane project, the anticipated total cost of interconnection and the incentive credit amount, the anticipated interconnection date, and the anticipated date of injection of biomethane into the utility's pipeline system. To the extent that the utility has not received complete information on interconnection costs paid by the developer of the biomethane project, the utility shall notify the Director of the Energy Division of any incomplete information regarding such costs as part of its notification letter. Following the interconnection and successful injection of biomethane for 30 days, and crediting the biomethane project with the incentive credit, the utility shall notify the Energy Division in a letter of the incentive credit amount awarded to the biomethane project.

The Energy Division shall be responsible for keeping track of the remaining balance available for use in this program. Each of the utilities may contact the Energy Division to determine whether there are sufficient funds remaining in this program to provide an incentive.

To keep track of interconnection costs, each utility shall be responsible for obtaining the interconnection costs from the biomethane project developer. Only the interconnection costs described in Section 2.2.2 of this decision shall be eligible toward the costs of computing this incentive payment.

If a biomethane project is interconnected to the gas utility and receives an incentive payment, the utility shall thereafter submit an annual report to the Director of the Energy Division summarizing the following: the number of interconnected biomethane projects on its system; the names and locations of these projects; the total interconnection costs for each project; the total amount of time needed for the interconnection process for each project; the amount and date in which the incentive payment was made; and the therms of biomethane injected into the utility's pipeline from each biomethane project. Following the first interconnected biomethane project, the utility shall submit this annual report to the Director of the Energy Division on January 15 of each year, until this reporting obligation terminates on January 16, 2021. The utility shall also electronically serve the annual report on the service list in this proceeding. These reports will assist the Commission in determining the effectiveness of this incentive program, any potential barriers in the interconnection process, and how much biomethane is being injected into the gas utilities' pipeline systems.

Structuring this policy and program in the above manner will encourage at least 26 biomethane projects to be developed and interconnected to the utilities' gas pipeline systems over the next five years, or sooner. Such projects can be developed using various in-state biogas resources (such as landfill, dairy, or wastewater treatment), so long as the biomethane meets the health and safety standards and protocols adopted in D.14-01-034, and the other interconnection standards set forth in the utility's tariff.

The successful development of such projects will create a low carbon renewable fuel source, which will reduce GHGs. The reduction of GHGs will benefit the public at large, the utility and its customers, and the operators of these biogas sources. In addition, through the biomethane projects adherence to the standards and protocols adopted in D.14-01-034, we can ensure that the biomethane can be interconnected and transported safely through the utility's pipeline system, and used safely at the customer's burner tip.

The incentive of 50% of the interconnection costs per biomethane project up to the $1.5 million limit, is reasonable given the environmental benefits of promoting a supply of low carbon renewable fuels, and the estimated costs of planning, constructing, interconnecting, and operating a biomethane project. Without such incentives, the current price of natural gas is likely to deter biomethane projects from being developed.

Due to the limited duration of this program, the $40 million cap, and the incentive amount per project, the cost to utility ratepayers should be minimal given the number of gas customers in each utility's service territory.[15]

Several of the parties suggest that the revenues from the cap and trade allowances be used to offset the biomethane producers' costs of ensuring that their biomethane meets the standards and protocols adopted in D.14-01-034, and that ongoing Commission proceedings address whether these revenues can be used for such a purpose. Some of these parties contend that because there are environmental benefits associated with the use of biomethane, that the cap and trade revenues should be used to offset the costs of the biomethane projects.

The ARB is responsible for the administration and enforcement of the cap and trade program. Under the ARB's cap and trade regulations, the electric utilities and the natural gas utilities were required to comply with these

[15] Several of the parties recommended in their comments on the proposed decision that the incentive amount of $1.5 million, and the $40 million program cap, be increased, and that the life of this incentive program be extended beyond five years. We decline to do so for all of the reasons set forth in this decision.

regulations beginning January 1, 2013, and January 1, 2015, respectively. The Commission opened R.11-03-012 to address the use of revenues from the auction of the GHG allowances allocated to the electric utilities from the ARB. The Commission opened R.14-03-003 to address the use of revenues to the gas utilities from the auction of the GHG allowances allocated to the gas utilities from the ARB.

R.11-03-012 has been examining how to allocate the revenues from the electric utilities' sale of the GHG allowances for over four years now, and a number of Commission decisions have been issued in that rulemaking. Due to that history, and because that rulemaking is addressing the allowances allocated to the electric utilities for the benefit of electric ratepayers, we are not persuaded that R.11-03-012 should be used as the forum to decide whether a portion of those allowances should be used to offset the biomethane producers' costs of complying with D.14-01-034.

R.11-05-005 was also suggested as the forum in which subsidies could be used to offset the biomethane producers' costs as part of the effort to achieve the target of 33% renewable energy generation. However, since that proceeding also has a significant regulatory history and is focused on electricity generation, R.11-05-005 is not an appropriate forum to address this offset issue.

The other suggested forum for addressing this issue is in R.14-03-003. The Commission recently adopted D.14-12-040 in that rulemaking. D.14-12-040 adopted a settlement which addressed certain policies, programs, rules and tariffs that the gas utilities must follow in order to comply with the cap and trade regulations. The issue of how the revenues from the auction of the GHG allowances allocated to the gas utilities is to be addressed in the second phase of that rulemaking. Today's decision does not prejudge how the revenue from the sale of gas allowances should be used. This is an issue to be determined by R.14-03-003.

We further note that the Commission has taken an active role in promoting the use of biogas to generate electricity, as well as a fuel. As pointed out by ORA, and above, the RPS process already have policies in place which place a value on renewable low carbon sources such as biogas. These biogas producers are in a position to sell the electricity produced from biogas fueled energy projects, or to sell the biogas, in the annual RPS solicitations. Electricity produced from biogas can also qualify to be sold into the Renewable Auction Mechanism. (See D.10-12-048, D.12-05-035, D.13-05-034, D.14-12-081.) As ORA points out, these market based solutions should make biomethane production more economical over time, while promoting the production and distribution of in-state biomethane.

Today's policy and program of the monetary incentive to help offset the interconnection costs of the biomethane producers will help pave the way, and jump start, the in-state production and distribution of biomethane, regardless of whether that biomethane is derived from landfill, dairies, or wastewater treatment plants. By providing this incentive program, biomethane producers will have a financial incentive to successfully develop such projects in California, and for the state to explore whether further encouragement of such projects is warranted. In addition to facilitating the development of biomethane within California, this incentive program will ensure that the health and safety concerns expressed in AB 1900, and as adopted in D.14-01-034, are adhered to.

To implement the monetary incentive policy and program, we authorize PG&E, SDG&E, SoCalGas, and Southwest Gas, to file Tier 2 Advice Letters to establish their respective balancing accounts to track the costs associated with the monetary incentive that a biomethane producer may receive if it successfully interconnects and operates a biomethane project with the gas utility, and for the utility to recover the monetary incentive amount in rates, plus interest, from its customers. Alternatively, each utility shall have the option of filing a Tier 2 Advice Letter to modify its existing balancing accounts to record and separately track the costs associated with the monetary incentive that a biomethane producer may receive. These advice letters shall be filed with the Energy Division within 90 days from today's date.

4. Comments on Proposed Decision

The proposed decision of Commissioner Carla J. Peterman in this matter was mailed to the parties in accordance with § 311, and comments were allowed pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure. Opening and reply comments were filed by various parties. Those comments have been reviewed and considered, and appropriate changes have been incorporated into the decision.

5. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner, and John S. Wong is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. This Rulemaking was opened to address the actions required of the Commission in AB 1900.

2. In response to AB 1900, the Commission in D.14-01-034 adopted concentration standards for 17 constituents of concern found in biomethane, and adopted certain monitoring, testing, reporting, and recordkeeping protocols that the biomethane producers and gas utilities must comply with.

3. The concentration limits and protocols adopted in D.14-01-034 were adopted to ensure the protection of human health, and the integrity and safety of the pipelines and pipeline facilities.

4. This phase of the proceeding was opened to consider who should bear the costs of complying with D.14-01-034, and to address policies and programs to promote the in-state production and distribution of biomethane.

5. The three types of costs for developing and operating a biomethane project in California are likely to consist of pre-injection costs, interconnection costs, and post-injection costs.

6. The biomethane proponents take the position that most or all of the costs of complying with the standards and protocols adopted in D.14-01-034 should be borne by utility ratepayers.

7. Some utilities and the advocates for end users take the position that all of the costs of developing, interconnecting, and operating a biomethane project should be borne by the biomethane producer.

8. Some of the biomethane proponents and the utilities recommend that the revenues from the sale of the cap and trade allowances be used to offset the biomethane production costs.

9. The purpose behind the adopted standards and protocols in D.14-01-034 is to ensure that the biogas can be treated and conditioned into merchantable biomethane that can be safely injected into the utilities' pipeline systems and used by customers.

10. Due to the adopted limits on certain constituents found in biomethane, and the adopted protocols, the biomethane producers will be faced with certain project costs, in addition to the other interconnection and project costs that all gas

suppliers must meet in order to interconnect with the utilities' gas pipeline systems.

11. There has been no demonstration in this phase of the proceeding, or a finding in D.14-01-034 that biomethane gas is safer or more reliable than fossil natural gas, or that it is less costly than fossil natural gas.

12. The two code sections in AB 1900 that allude to costs are found in Public Resources Code § 25326, which refers to "impediments," and § 399.24, which refers to "policies and programs" that promote and facilitate the development of biomethane.

13. Our cost treatment of the biomethane producers is the same as how the natural gas producers who interconnect to the utilities' pipeline systems are treated.

14. All of the natural gas producers are responsible for their own costs of conditioning their gas to meet the gas interchangeability specifications.

15. The higher cost of treating and conditioning biogas to convert it into merchantable biomethane is simply part of the inherent composition of the biogas itself, and does not discriminate nor prevent the biomethane producers from gaining access to the utilities' pipeline systems.

16. Unless the biomethane producer obtains an IRS ruling that no CIAC tax will be incurred, the biomethane producer must pay a gross-up for the CIAC tax that may be imposed if a utility supplies the gas used for upstream blending of the biomethane.

17. The adoption of the monetary incentive program will encourage biomethane projects to be developed and interconnected to the utilities' gas pipeline systems over the next five years or sooner, and will incentivize potential biomethane producers to decide if such biomethane projects should be built, and

whether such projects are economically feasible in light of current natural gas prices.

18. Interconnection costs are likely to make up a large part of the overall costs of a biomethane project.

19. The successful development of the biomethane projects will create a low carbon renewable fuel source, which will reduce GHGs and provide other environmental benefits to the public at large, the utility and its customers, and the operators of these biogas sources.

20. Through the biomethane projects' adherence to the standards and protocols adopted in D.14-01-034, we can ensure that the biomethane can be interconnected and transported safely through the utility's pipeline system, and distributed safely for use at the customer's burner tip.

21. The incentive amount per interconnecting project is reasonable given the environmental benefits of promoting a supply of low carbon renewable fuels, and the estimated costs associated with a biomethane project.

22. Without the monetary incentive program, the current price of natural gas is likely to deter biomethane projects from being developed.

23. Due to the limited duration of the program, the $40 million cap, and the incentive amount per project, the cost to utility ratepayers should be minimal given the number of gas customers in each utility's service territory.

24. Due to the regulatory history and the focus of R.11-03-012 and R.11-05-005, those proceeding are not the appropriate forum to address whether the use of the revenues from the auction of the GHG allowances should be used to offset the biomethane producers' costs.

25. The Commission has taken an active role in various proceedings to promote the use of biogas to generate electricity, as well as a fuel.

26. Today's policy and program of the monetary incentive to help offset the interconnection costs will help pave the way, jump start, and facilitate the development of biomethane within California, while ensuring that the health and safety concerns expressed in AB 1900, and as adopted in D.14-01-034, are adhered to.

Conclusions of Law

1. Section 399.24 and AB 1900 do not specifically address who should be responsible for the costs of complying with the standards and protocols adopted in D.14-01-034.

2. AB 1900 did not add or amend any code sections to require the Commission to allocate the compliance costs of D.14-01-034 onto a particular group or entity.

3. The language in § 784 about "nondiscriminatory open access to its gas pipeline system" suggests that the allocation of the costs of interconnection should remain the same for both biomethane producers and traditional natural gas suppliers.

4. Section 740.3 is not applicable to the biomethane producers' costs because that code section focuses on low-emission vehicles, whereas AB 1900's focus is on the development and use of biomethane.

5. The cost of complying with D.14-01-034 is to be borne by the biomethane producers.

6. The cost of constructing and operating the equipment needed to treat and condition the biomethane in order to meet the standards and protocols in D.14-01-034 may limit the procurement and distribution of biomethane in California.

7. To allocate some or all of the costs of complying with D.14-01-034 onto the utility and its shareholders would be discriminatory, and in violation of § 784.

8. Section 399.24 explicitly provides for the adoption of policies and programs that promote the production and distribution of biomethane.

9. To fulfill the intent of § 399.24, the Commission should adopt a policy of encouraging the in-state production and distribution of biomethane through the adoption of a monetary incentive program as described in this decision, and as set forth in Conclusions of Law 10 through 16.

10. In order to specify which costs incurred by the developer of the biomethane project are eligible for the monetary incentive program, and to describe the program mechanics related to the distribution of funds to the developer, the utilities shall jointly fill a Tier 2 Advice Letter to modify each of their existing interconnection tariffs. This Advice Letter shall set forth a description of the types of costs that qualify as interconnection costs under the monetary incentive program. In addition, the Advice Letter shall specify the process for determining if a facility has met the 30-day operational requirement, and the process for the distribution of the incentive payment. The Energy Division has discretion over the content and disposition of the advice letter and may elect to hold an informal workshop on the utilities' proposal in this Advice Letter before approving or rejecting this Advice Letter filing.

11. The total monetary incentives under this program shall be capped at $40 million over the five-year duration of this program, and if the $40 million in incentives is exhausted before the expiration of the five-year period, this program shall terminate. If the five-year period expires and there are unused incentives remaining, this program shall end at the end of that period. If there are funds remaining at the time of program termination, then biomethane projects that

have started to inject merchantable biomethane into the utility's pipeline system as of the termination date of this program are eligible for an incentive payment if they otherwise meet the program criteria.

12. Each biomethane project in California that successfully complies with the gas specifications set forth in a gas utility's tariff, including compliance with the standards and protocols adopted in D.14-01-034, and which successfully interconnects with the utility's pipeline system and remains in operation for a minimum of 30 days, with a flow each day for each of those 30 days, shall be entitled to 50% of the interconnection costs incurred by the biomethane producer, up to a total payment of $1.5 million, following this 30-day operational period. This one-time payment shall be credited to the biomethane producer by the interconnecting utility within 60 days after the 30-day operational period expires. This credit to the biomethane producer shall be included in the gas rates of the interconnecting utility and recovered from the utility's customers in such rates on an equal cents per therm basis with interest.

13. At least 90 days prior to the anticipated interconnection date, the utility shall notify the Director of the Energy Division in a letter of the name, developer, and location of the biomethane project, the anticipated total cost of interconnection and the incentive credit amount, the anticipated interconnection date, and the anticipated date of injection of biomethane into the utility's pipeline system. Following the interconnection and successful injection of biomethane for 30 days, and crediting the biomethane project with the incentive credit, the utility shall notify the Energy Division in a letter of the incentive credit amount awarded to the biomethane project.

14. The Energy Division shall be responsible for keeping track of the remaining balance available for use in this program. Each of the utilities may

contact the Energy Division to determine whether there are sufficient funds remaining in this program to provide an incentive.

15. To keep track of the interconnection costs, each utility shall be responsible for obtaining the interconnection costs from the biomethane project developer. Only the interconnection costs described in Section 2.2.2 of this decision shall be eligible toward the costs of computing this incentive payment.

16. If a biomethane project is interconnected to the gas utility and receives an incentive payment, the utility shall thereafter submit an annual report, as described, to the Director of the Energy Division summarizing the following: the number of interconnected biomethane projects on its system; the names and locations of these projects; the total interconnection costs for each project; the total amount of time needed for the interconnection process for each project; the amount and date in which the incentive payment was made; and the therms of biomethane injected into the utility's pipeline from each biomethane project. This annual report shall be submitted by the utility to the Director of the Energy Division on January 15 following the first biomethane project interconnected with the utility, and on each subsequent January 15 until this reporting obligation terminates on January 16, 2021. The utility shall also electronically serve the annual report on the service list in this proceeding.

17. Today's decision does not prejudge whether the second phase of R.14-03-003 should address the issue of whether the revenues from the auction of the GHG allowances should be used to offset the biomethane producers' costs.

18. PG&E, SDG&E, SoCalGas, and Southwest Gas, shall file, within 90 days from today's date, Tier 2 Advice Letters to establish their respective balancing accounts to track the costs associated with the monetary incentive that a biomethane producer may receive if it successfully interconnects and operates a

biomethane project with the gas utility, and to recover the monetary incentive amount in rates, plus interest, from its customers.

O R D E R

IT IS ORDERED that:

1. The costs of complying with the health and safety-related standards and protocols adopted in Decision 14-01-034 shall be borne by the biomethane producers.

2. In accordance with Public Utilities Code Section 399.24, a monetary incentive program, as described herein, is created and adopted to encourage the in-state production and distribution of biomethane.

    a. This monetary incentive program shall be in effect for a period of five years from the effective date of this decision. If there is any unused incentive funding at the end of this five-year period, this program shall terminate. If there are funds remaining at the time of program termination, then biomethane projects that have started to inject merchantable biomethane into the utility's pipeline system as of the termination date of this program are eligible for an incentive payment if they otherwise meet the program criteria.

    b. The Commission authorizes total funding of $40 million for this monetary incentive program.

    c. A biomethane project in California that successfully complies with the standards and protocols adopted in Decision 14-01-034, and which successfully interconnects with the utility's pipeline system and remains in operation for a minimum of 30 days, with a flow each day for each of those 30 days, shall be entitled to a one-time payment of 50 percent of the biomethane project's interconnection costs, up to the amount of $1.5 million, following this 30-day operational period. This one-time incentive payment shall be credited to the biomethane producer by the interconnecting utility within 60 days after the 30-day operational period expires.

d. To keep track of the interconnection costs, each utility shall be responsible for obtaining the interconnection costs from the biomethane project developer. Only the interconnection costs described in Section 2.2.2 of this decision shall be eligible toward the costs of computing this incentive payment.

e. At least 90 days prior to the anticipated interconnection date, the utility shall notify the Director of the Energy Division in a letter of the name, developer, and location of the biomethane project, the anticipated total cost of interconnection and the incentive credit amount, the anticipated interconnection date, and the anticipated date of injection of biomethane into the utility's pipeline system. To the extent that the utility has not received complete information on interconnection costs paid by the developer of the biomethane project, the utility shall notify the Director of the Energy Division of any incomplete information regarding such costs as part of its notification letter. Following the interconnection and successful injection of biomethane for 30 days, and crediting the biomethane project with the incentive credit, the utility shall notify the Energy Division in a letter of the incentive credit amount awarded to the biomethane project.

f. The Energy Division shall be responsible for keeping track of the remaining balance available for use in this program. Each of the utilities may contact the Energy Division to determine whether there are sufficient funds remaining in this program to provide an incentive.

g. The interconnecting utility is authorized under this program to include each incentive awarded to a biomethane project in its gas rate, and to recover such amount from its customers, with interest, through that gas rate.

h. If a biomethane project is interconnected to the gas utility and receives an incentive payment, the utility shall thereafter submit an annual report to the Director of the Energy Division summarizing the following: the number of interconnected biomethane projects on its system; the names and locations of these projects; the total interconnection costs for each project; the total amount of time needed for the interconnection process for each project; the amount and date in which the incentive payment was made; and the therms of biomethane injected into the utility's pipeline from each biomethane project. This annual report shall be submitted by the utility to the Director of the Energy Division on January 15 following the first biomethane project interconnected with the utility, and on each subsequent January 15 until this reporting obligation terminates on January 16, 2021. The utility shall also electronically serve the annual report on the service list in this proceeding.

3. In order to specify which costs incurred by the developer of the biomethane project are eligible for the monetary incentive program, and to describe the program mechanics related to the distribution of funds to the developer, the utilities shall jointly fill a Tier 2 Advice Letter to modify each of their existing interconnection tariffs. This Advice Letter shall set forth a description of the types of costs that qualify as interconnection costs under the monetary incentive program. In addition, the Advice Letter shall specify the process for determining if a facility has met the 30-day operational requirement, and the process for the distribution of the incentive payment. The Energy Division has discretion over the content and disposition of the Advice Letter and may elect to hold an informal workshop on the utilities' proposal in this Advice Letter before approving or rejecting this Advice Letter filing.

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

within 90 days from today's date, Tier 2 Advice Letters to establish their respective balancing accounts to track the costs associated with the monetary incentive program that a biomethane producer may receive if it successfully interconnects and operates a biomethane project with the gas utility, and to recover the monetary incentive amount in rates, plus interest, from its customers. Alternatively, these utilities may file a Tier 2 Advice Letter to modify its existing balancing accounts to record and separately track the costs associated with the monetary incentive program that a biomethane producer may receive.

5. Rulemaking 13-02-008 is closed.

This order is effective today.

Dated June 11, 2015, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
Commissioners

Commissioner Liane M. Randolph,
being necessarily absent, did not
participate.