RENEWABLE NATURAL GAS (RNG)

TOOL KIT

SoCalGas

Last updated September 2021

FOREWORD

SoCalGas® believes that renewable gas will play a fundamental role in California's clean energy future, alongside wind and solar. Developing renewable gas resources from our state's abundant organic waste streams provides an exciting solution to California's ambitious climate change goals, while also creating additional renewable fuel and jobs for our communities, and potentially billions of dollars in economic benefits.

SoCalGas has more than a decade of experience fostering the growth of renewable gas. Our culture is deeply rooted in customer service and we are committed to finding innovative solutions to meet customers' needs. To date, several projects have demonstrated that biogas can be successfully cleaned to meet pipeline quality specifications.

- In February 2019, Calgren Dairy Fuels, working with SoCalGas, began injecting RNG sourced from cow manure from dairy clusters in Pixley, California.
- At a wastewater treatment plant in Point Loma, California, SoCalGas collaborated with its sister company, San Diego Gas & Electric Company (SDG&E®), to install a renewable gas pipeline interconnection facility to deliver renewable gas into the SDG&E pipeline network.
- In July 2018, CR&R, a waste and recycling management company, began injecting renewable natural gas sourced from landfill-diverted food and green waste into SoCalGas's pipeline to fuel CR&R's waste hauling trucks.

California has a challenging path ahead. Meeting the state's climate goals will require a fundamental shift in the way we power our homes and businesses, transport goods, and manage the lifecycle of our food and waste. By developing renewable gas in California, we can help to meet our climate goals sooner, while diversifying our carbon-free energy sources and improving energy resilience and reliability. SoCalGas stands ready to support biogas producers and to pursue renewable gas projects with pipeline injection. We created this tool kit to assist producers with information and technical guidance to support the interconnection process.

TABLE OF CONTENTS

RENEWABLE NATURAL GAS

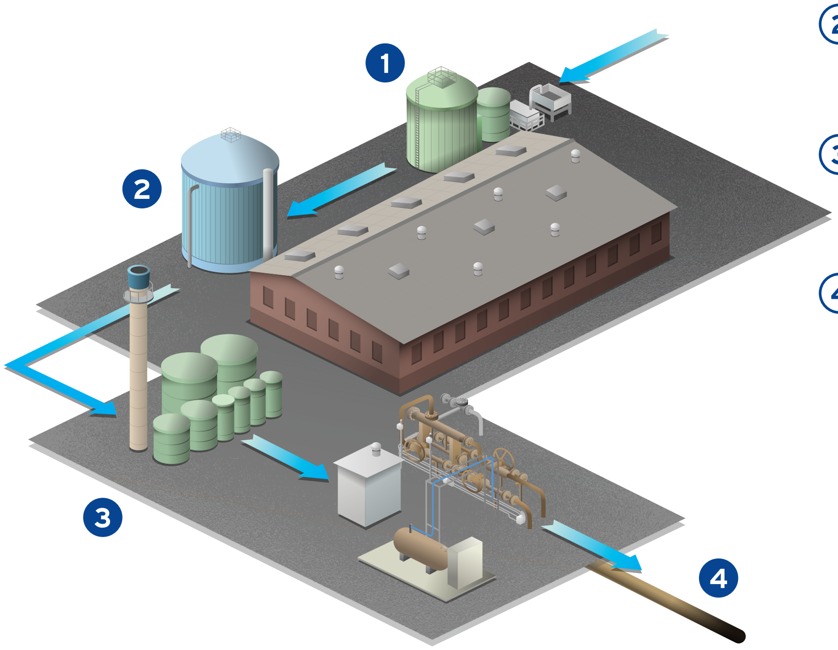
PART OF CALIFORNIA'S RENEWABLE ENERGY FUTURE

WHAT IS RENEWABLE NATURAL GAS?

Traditionally, pipeline natural gas comes from deep underground wells and is often associated with petroleum production. On the other hand, renewable natural gas (RNG) is natural gas derived from organic waste material found on the surface of the earth. In California, and throughout the United States, there are a variety of sources of this organic waste, which we see in daily life. These include food waste, garden and lawn clippings, animal and plant-based material as well as degradable carbon sources such as paper, cardboard and wood. The abundance of this material can allow for production of biogas in significant quantities.

The most common source of biogas is the naturally occurring biological breakdown of organic waste at facilities such as wastewater treatment plants and landfills. Biogas typically consists of methane and carbon dioxide, with traces of other elements. Biogas is cleaned and conditioned to remove or reduce non-methane elements in order to produce RNG. The converted RNG is then put into the utility pipeline as a replacement for traditional natural gas. This process helps promote the safe and reliable operation of the natural gas pipeline distribution network as well as the natural gas equipment and appliances used by customers.

HOW ORGANIC WASTE IS CONVERTED INTO RNG



1. Waste products, such as sludge, food waste or manure are processed in a biodigester.
2. The biodigester breaks down the organic material to create biogas – a mixture of methane and other elements.
3. The biogas can then be processed and conditioned leaving behind RNG, which can be used interchangeably with traditional natural gas.
4. This RNG can be used where it is produced for things like generating electricity or fueling vehicles, or it can be injected into a utility pipeline for transportation to other customers.

SoCalGas™

GREENHOUSE GAS REDUCTIONS

RNG comes from organic sources that originally removed carbon dioxide from the atmosphere during photosynthesis, so it is considered a carbon-neutral fuel. Often, RNG can be produced from organic waste that would otherwise decay and create methane emissions. Capturing these methane emissions can actually make RNG a carbon-*negative* fuel by removing emissions from the atmosphere. Reducing carbon dioxide and other greenhouse gas levels is important to help reduce global warming.

GREEN ENERGY AROUND THE CLOCK HELPS CALIFORNIA'S ECONOMY

Unlike certain other sources of renewable energy, such as solar and wind technologies, RNG is available 24 hours per day, seven days a week. It can be deployed when and where it is needed through the existing pipeline network. Converting waste products into RNG could help California meet its energy needs with local resources. Investing in RNG production in California could help create jobs in all regions of the state while improving air quality by better managing our waste streams.

UP TO 400 PERCENT CARBON DIOXIDE REDUCTIONS FOR TRANSPORTATION

Studies conducted by the University of California at Davis have estimated that more than 20 percent of California's current residential natural gas use can be provided by RNG derived from our state's existing organic waste alone[1]. This can help reduce the need for other fossil-based fuels, and increase our supplies with a local renewable fuel. According to the California Air Resources Board[2], RNG sourced from landfill diverted food and green waste can provide a 125 percent carbon dioxide reduction, and RNG from dairy manure can result in a 400 percent carbon dioxide reduction when replacing traditional vehicle fuels.

More than half of all natural gas dispensed in California for transportation is RNG, powering buses, refuse trucks and heavy-duty trucks.

SOCALGAS® IS A SUPPORTER OF RNG

As part of our commitment to help the environment and support California in meeting its greenhouse gas reduction goals, SoCalGas® offers expertise and assistance to customers and project developers who want to convert organic waste material into biogas or RNG. Through our network of natural gas pipelines, SoCalGas offers the opportunity for RNG to be accepted into our transmission and distribution system and delivered to our customers.

FIND OUT MORE

For more information visit:

socalgas.com/rng

Or contact our Market Development Team at:

MarketDevelopment@socalgas.com

1. "The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute", Prepared for the California Air Resources Board and the California Environmental Protection Agency by Amy Jaffe, Principal Investigator. STEPS Program, Institute of Transportation Studies, UC Davis: https://ww3.arb.ca.gov/research/apr/past/13-307.pdf

2. "Low Carbon Fuel Standard Pathway Certified Carbon Intensities": https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm

RENEWABLE NATURAL GAS (RNG)

INTERCONNECTION PROCESS

OVERVIEW

Renewable Gas (RG) is gas from biogenic or other renewable sources, such as biogas, biomass, or power to Gas from renewable electricity that has been conditioned or upgraded to be interchangeable with traditional natural gas.

SoCalGas® Rule 45, "Standard Renewable Gas Interconnection", describes the specifications, terms, and conditions adopted that must be met in order for SoCalGas to accept RG into its pipeline network.

The process begins with a renewable source, such as anaerobic digestion of landfills or landfill diversion facilities, dairies, and wastewater treatment plants. The raw biogas is mainly methane and carbon dioxide with traces of other elements such as water, hydrogen sulfide, siloxanes, nitrogen, and oxygen.

Prior to injection into the pipeline, renewable gas must be conditioned and upgraded to remove or reduce non-methane elements to promote the safe and reliable operation of the pipeline network and end-use natural gas equipment.

BIOGAS PROCESSING TECHNOLOGIES

There are several methods and technologies available to condition biogas. Technology selection can be based on many criteria, including renewable gas source and product gas makeup as well as site and operating conditions. Some examples of technologies used in biogas conditioning include:

- High-selectivity membranes
- Pressure swing adsorption systems
- Water scrubbing systems
- Solid scavenging media
- Regenerative or non-regenerative adsorbent media
- Catalytic O_2

It is common to find a combination of these technologies working in conjunction to meet a set of specifications.

Biomethane Producer's Piping

SoCalGas Pipeline Network

Utility Interconnection

BIOMETHANE INJECTION PROCESS

SoCalGas Rule No. 45, "Standard Renewable Gas Interconnection," provides detailed information on the requirements to interconnect and inject renewable gas into utility pipelines. The section below describes the three basic steps of the interconnection process.

STEP 1

Interconnection Screening Study

The process starts with the execution of a Service Agreement and Confidentiality Agreement and request for an Interconnection Screening Study, which determines the utility's downstream capacity to take the renewable natural gas away from the interconnection point. The utility provides one free Interconnection Screening Study per project and requires up to 15 business days to complete and return to Interconnector.[1]

STEP 2

Preliminary Engineering Study

The Preliminary Engineering Study (PES) requires an Attachment A-1 agreement and develops the Total Installed Cost estimate within +100%/-50% and preliminary Piping and Instrumentation Diagrams (P&ID's). Interconnectors must pre-fund the Preliminary Engineering Study. The PES costs approximately $100,000 and typically requires 90 business days to complete.[1]

STEP 3

Detailed Engineering Study

The Detailed Engineering Study (DES) requires an Attachment A-2 agreement and develops the Total Installed Cost estimate accurate to +50%/-30% and Issued for Construction P&ID's. Interconnectors must pre-fund the Detailed Engineering Study. These costs typically start at $325,000 and requires 180 business days to complete and return to Interconnector.[1]

BIOMETHANE INTERCONNECTION INCENTIVE PROGRAM

In 2015, the California Public Utilities Commission (CPUC) established the Biomethane Interconnector Monetary Incentive Program[2]. This program may provide an incentive that can contribute up to 50 percent of interconnection costs, with a cap of $3 million per project. The cap is $5 million for dairy cluster projects, defined as three or more dairies in close proximity. In December 2020, the CPUC approved an additional $40,000,000 into the Biomethane Interconnector Monetary Incentive Program of which SoCalGas was allocated $19,704,000 in additional incentive funds. During the same proceedings, San Diego Gas & Electric (SDG&E) was allocated $2,708,000 in additional incentive funds. The program is described in detail in SoCalGas Rule 45 Section I (5). Your SoCalGas account executive can help to navigate the qualification and application process for this incentive.

FIND OUT MORE

For more information, please visit:

socalgas.com/rng

or contact us at:

GasStudyRequests@socalgas.com

[1] The provided estimated costs are based on historical projects and can vary based on site specific conditions. The estimated costs and timeline does not include requests involving a deviation from the gas quality specifications.

[2] D.15-06-02: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K572/152572023.PDF

This program is funded by California utility customers and administered by Southern California Gas Company (SoCalGas) under the auspices of the California Public Utilities Commission. Program funds, including any funds utilized for rebates or incentives, will be allocated on a first come, first-served basis until such funds are no longer available. This program may be modified or terminated without prior notice.

SoCalGas™

TOOLS AND TIPS

FOR RENEWABLE NATURAL GAS (RNG) PROJECTS CONNECTING TO THE SOCALGAS® PIPELINE

INTRODUCTION

Renewable natural gas (RNG) is a carbon-neutral gaseous fuel that replaces traditional natural gas. RNG can play an important role in reducing the impact of greenhouse gas (GHG) emissions from the natural gas system. RNG typically comes from biogas sources such as landfills, wastewater treatment facilities, manure, and food and green waste. This raw biogas contains byproducts or compounds that need to be removed so they won't negatively impact end-use equipment or the environment. Removing these compounds, also called conditioning and/or upgrading, ensures the RNG can meet pipeline standards, as defined in SoCalGas' Tariff Rule No. 30.[1] Conditioning and upgrading biogas to meet pipeline standards typically includes removal of water, carbon dioxide (CO_2), hydrogen sulfide (H_2S) and other elements. Numerous commercially-available conditioning and upgrading systems are already in use here in the United States and in Europe.

Once RNG is conditioned and upgraded, it can be injected into SoCalGas® pipelines. The location of the interconnection is critical. A nearby pipeline must have the capacity to accept the volume of RNG produced. Customer demand fluctuates daily and seasonally, and natural gas pipelines typically flow in one direction — from higher pressure feeder systems to lower pressure distribution systems. For this reason, SoCalGas must conduct an engineering analysis to find a feasible location.

WHAT FACTORS DETERMINE THE VIABILITY OF PRODUCING PIPELINE RNG?

The necessary components and related costs to condition and upgrade raw biogas and inject it into the pipeline can vary, depending on the source and quality of the raw biogas as well as the project location. Below a certain quality level and scale, it may not be economical to produce RNG without incentives. Typically, the larger the project and the cleaner the raw biogas, the more economically feasible that project will be. Project scale isn't the only design factor that may impact project economics. Some other major components that can play a significant, but often manageable, role in project costs are:

- Equipment to remove nitrogen and oxygen (capital and operating cost driver)
- Compression for processing and pipeline injection (capital and operating cost driver)
- Long-distance high pressure pipeline extension (capital cost driver)

1. **REMOVING NITROGEN AND/OR OXYGEN**
Often landfills and other biogas sources have air infiltration, meaning that nitrogen and oxygen can be inadvertently mixed with raw biogas. Both nitrogen and oxygen removal can increase capital and operating costs while reducing methane recovery efficacy. A recent Black & Veatch study estimated that eliminating the need to remove nitrogen during biogas processing can result in up to 20 to 25 percent cost reduction.[2] Because of this, it is often more cost-effective to reduce air infiltration upstream of the conditioning system by improving system integrity and adjusting landfill gas collection systems, or by implementing measures that limit or avoid introduction of air in anaerobic digesters.

2. **COMPRESSION FOR PROCESSING AND PIPELINE INJECTION**
Several biogas processing technologies require gas compression, and depending on the utility pipeline network pressure, final injection of RNG may require higher levels of compression (400 PSIG and greater). Conversely, lower pressure utility pipeline networks may be closer, but they typically have less connected demand available to accept RNG deliveries. Compression energy and maintenance costs can account for one-half to two-thirds of total operating costs, depending on final delivery pressure required. Siting projects to access lower pressure pipelines for injection can result in up to 5 to 15 percent savings in total operating costs.[3]

3. **DISTANCE TO NEAREST VIABLE INJECTION LOCATION**
The length of the pipeline extension necessary to interconnect with the utility system is also a critical cost driver. Finding routes for pipelines that require minimal traffic control and re-paving during installation can significantly reduce costs. For example, a 1,000-foot pipeline could equate to around one percent of estimated project lifecycle costs for a typical economically sized upgrade and injection project but can grow up to 20 percent of project lifecycle costs when a two-mile pipeline is required.[3]

HOW CAN I FIND OUT MORE ABOUT SITING A PROJECT NEAR AN EXISTING PIPELINE?

To get a general idea about project siting, review the SoCalGas pipeline maps online at: **socalgas.com/rng**

Keep in mind that the existence of a pipeline on this map is not a guarantee it will have the capacity necessary to support renewable natural gas injection. These maps also don't include many lower-pressure pipelines which could provide injection access. Learn more about the interconnection process at: **socalgas.com/rng**

The SoCalGas low-carbon fuels Market Development Team can also provide you with more information about renewable natural gas project development. You can email the team at: **MarketDevelopment@socalgas.com**

1. socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf

2. "Biogas Conditioning and Upgrading Technologies, Technical Characterization and Economic Evaluation" Black & Veatch, Commissioned by SoCalGas, 2015.

3. The provided estimates are based on internal evaluation and assessment work and can vary based on site-specific conditions.

SoCalGas™

RENEWABLE NATURAL GAS (RNG)

GAS QUALITY STANDARDS

THE SOCALGAS® GAS QUALITY STANDARDS

SoCalGas® Rule 30 describes the requirements for natural gas to be injected into the utility pipeline. These requirements reflect the first and foremost priority of SoCalGas to protect its customers, employees, contractors and pipeline system, as well as the public. The standards described in Rule 30 cover two major aspects: gas constituent limits (composition-based specifications) and gas interchangeability specifications (performance-based quality specifications). Gas constituent limits restrict the concentration of gas impurities to protect pipeline integrity and ensure safe and proper combustion in end-user equipment. The interchangeability specifications address end-user combustion performance, ensuring safe and proper combustion for customers.

SoCalGas Rule 30, Section I.5. provides interconnectors with the option to request specific deviations from meeting the defined gas quality specifications in Section I.3. If SoCalGas determines such gas will not negatively impact system operations, SoCalGas is then required to file an Advice Letter for California Public Utilities Commission (CPUC) approval before the gas is permitted to flow into the utility pipeline system.

The table below shows some gas quality standards from across the United States[1]. These requirements are specific to each pipeline network.

Pipeline Company	Heating Value (Btu/scf)		Water Content	Various Inerts			Hydrogen Sulfide (H_2S)
	Min	Max	(Lbs/ MMscf)	CO_2	O_2	Total Inerts	(Grain/100scf)
SoCalGas	970	1150	7	3%	0.20%	4%	0.25
Dominion Transmission	967	1100	7	3%	0.20%	5%	0.25
Equitrans LP	970	–	7	3%	0.20%	4%	0.3
Florida Gas Transmission Co.	1000	1110	7	1%	0.25%	3%	0.25
Colorado Intrastate Gas Co.	968	1235	7	3%	0.001%	–	0.25
Questar Pipeline Co.	950	1150	5	2%	0.10%	3%	0.25
Gas Transmission Northwest Co.	995	–	4	2%	0.40%	–	0.25

TYPICAL GAS CONSTITUENTS FOUND IN BIOGAS

In 2012, the CPUC issued a decision in the Biomethane Phase I Order Instituting Rulemaking (OIR)[2] in response to California Assembly Bill 1900 (AB 1900) (Gatto, 2012). In this OIR the CPUC, in collaboration with other state agencies, adopted 17 constituents of concern that can potentially be found in biogas. The CPUC established reasonably acceptable levels of these constituents to protect human health and system integrity, and ordered them to be included in SoCalGas Rule 30 (See Section J.5). As directed by AB 1900, the protection levels for each constituent along with the monitoring, testing, reporting and recordkeeping requirements are reviewed and updated every five years, or sooner, if new information becomes available. Siloxanes, one of the constituents of concern,

1. Source: American Gas Association, Report #4A Natural Gas Contract Measurement and Quality Clauses (2009). Some standards have been updated based on publicly available information

2. R.13-02-008

can be found in a variety of consumer products. Siloxanes are typically present in biogas created at landfills and wastewater treatment plants, and can sometimes be found in diverted food and green waste biogas. Siloxanes can create problems in end-user equipment because during combustion, they can coat equipment with a fine layer of silica and silocates. This is especially problematic for sensitive end-user equipment found in Southern California. For example, siloxanes can cause expensive catalysts to fail. These catalysts perform an important service reducing emissions to keep our air clean, and are found in all fuel cells, natural gas vehicles, and the majority of electric power generators. The local aerospace industry and other manufacturers have also expressed concerns with siloxanes potentially entering their sensitive facilities through the fuel supply.

CLEANING BIOGAS TO PIPELINE QUALITY STANDARDS

Several methods and technologies are available to condition and upgrade biogas into renewable natural gas (RNG) and remove constituents of concern. Technology selection can be based on many criteria, including the makeup of the biogas as well as site and operating conditions. Some examples of technologies used in biogas conditioning and upgrading are:

- High-selectivitymembranes
- Pressure swing adsorption systems
- Water scrubbing systems
- Solid scavenging media
- Regenerative or non-regenerative adsorbent media
- Catalytic O_2

It is common to find a combination of these technologies working together to meet a set of specifications.

GAS CONSTITUENT MONITORING AND MEASUREMENT

Gas quality is maintained by two different types of monitoring, based on the Biomethane OIR requirements. Some attributes such as carbon dioxide, total inerts, and heating value are continuously monitored at the point of utility interconnection. Other constituents, such as siloxanes, are monitored by taking quarterly or annual samples of the gas and testing it in a laboratory.

SoCalGas Rule 30 requires gas quality testing on biomethane constituents of concern be done by independent certified third-party laboratories[3]. The NELAC Institute (TNI) maintains a list of laboratories (http://lams.nelac-institute.org/search) which are able to test for constituents of concern, including the measurement of siloxanes below the defined trigger level.

FIND OUT MORE

For more information, please visit:

socalgas.com/rng

or contact our Low Carbon Fuels Market Development Team at:
MarketDevelopment@socalgas.com

[3] SoCalGas utilizes an independent third party laboratory and may include a performance sample when measuring siloxane levels.

BIOGAS CONDITIONING/UPGRADING
SERVICES TARIFF

The Biogas Conditioning/Upgrading Services Tariff is a fully elective, optional, nondiscriminatory tariff service for customers that allows SoCalGas® to plan, design, procure, construct, own, operate, and maintain biogas conditioning and upgrading equipment on customer premises. The biogas will be conditioned/upgraded to the gas quality specifications as requested by the customer and agreed to by SoCalGas.

KEY ELEMENTS

- The Biogas Conditioning/Upgrading Services Tariff is a service fully paid for by participating customers. Monthly tariff services pricing will vary based on the size, scope and location of each project.
- The Biogas Conditioning/Upgrading Services Tariff will be provided through a long-term Service Agreement, typically 10-15 years. At the end of the contract term, customer may request to extend the term of the agreement or ask SoCalGas to remove the equipment.
- The tariff service is neither tied to any other tariff or non-tariff services the customer may receive from SoCalGas nor will it change the manner in which these services are delivered.
- Non-utility service providers may offer services that are the same or similar to the Biogas Conditioning/Upgrading Services Tariff and customers are encouraged to explore these service options.
- To assist customers in understanding all of their service options, SoCalGas maintains and provides customers with a list of non-utility service providers at **socalgas.com/rng**

FREQUENTLY ASKED QUESTIONS

WHAT ARE SOME EXAMPLES OF END-USE APPLICATIONS THAT WOULD USE THIS TARIFF?

Examples of customer end-use applications that can be served by the Biogas Conditioning/Upgrading Services Tariff include but are not limited to: renewable natural gas for pipeline injection, compressed natural gas for vehicle refueling stations, and conditioned/upgraded biogas for combined heat and power (CHP) facilities.

IS THE BIOGAS CONDITIONING/UPGRADING SERVICES TARIFF MANDATORY IF CUSTOMERS WANT TO PUT RENEWABLE NATURAL GAS (BIOMETHANE) INTO THE PIPELINE?

No. Customers may elect to install and maintain their own biogas conditioning and upgrading equipment or engage a third party to install and maintain their biogas conditioning and upgrading equipment rather than take the Biogas Conditioning/Upgrading Services Tariff from SoCalGas.

DOES ENROLLMENT IN THIS TARIFF RESULT IN ANY PREFERENTIAL TREATMENT WHEN IT COMES TO GETTING GAS SERVICE?

No. The Biogas Conditioning/Upgrading Services Tariff is a fully elective, optional, non-discriminatory tariff service that is neither tied to any other tariff or non-tariff services the customer may receive from SoCalGas nor will it change the manner in which these services are delivered. As an example, requests for an interconnection capacity study are processed on a "first come, first served" basis for all customers, including customers that elect to take the Biogas Conditioning/Upgrading Services Tariff and customers that do not.

WHO CAN RECEIVE SERVICE UNDER THE BIOGAS CONDITIONING/UPGRADING SERVICES TARIFF?

The Biogas Conditioning/Upgrading Services Tariff is generally applicable to producers of biogas. Any agreement to provide service under the Biogas Conditioning/Upgrading Services Tariff is at the discretion of SoCalGas and will depend on non-discriminatory factors such as safety, SoCalGas resource availability, technical feasibility, and acceptability of commercial terms.

UNDER THIS SERVICE, WILL SOCALGAS BE RESPONSIBLE FOR ALL EQUIPMENT CONNECTED TO THE BIOGAS CONDITIONING AND UPGRADING FACILITIES?

No. This service does not cover any activities either upstream from the receipt point of untreated biogas or downstream from the point of service delivery for conditioned/upgraded biogas.

WHO OWNS BIOGAS TREATED UNDER THE BIOGAS CONDITIONING/UPGRADING SERVICES TARIFF?

Any gas processed under the Biogas Conditioning/Upgrading Services Tariff is solely owned by the customer before, during, and after processing. It is solely the customer's responsibility to ensure that treated biomethane intended for pipeline injection meets Rule 30 standards for pipeline injection of customer-owned gas. The customer is solely responsible for any damage to pipeline integrity or human health which results from improperly treated gas entering SoCalGas' natural gas pipeline system.

FIND OUT MORE

For more information, please visit:

socalgas.com/rng

or contact our Low Carbon Fuels Market Development Team at:
MarketDevelopment@socalgas.com

SoCalGas

BIOGAS INDUSTRY LIST

Last updated March 2022

NORTH AMERICA

UNITED STATES

Acrion Technologies www.acrion.com	7777 Exchange Street, Suite 5 Cleveland, OH 44124	314-669-2612
AECOM www.aecom.com	1999 Avenue of the Stars, Suite 2600 Los Angeles, CA 90067	213-593-8100
Air Liquide Advanced Separations www.airliquideadvancedseparations.com/our-membranes/biogas	200 GBC Drive Newark, DE 19702	484-666-9088
AMP Americas www.ampamericas.com	811 W. Evergreen Ave, Suite 201, Chicago, IL 60642	949-514-8518
Anacapa Engineering and Design, Inc. www.anacapa.com	9100 Ming Avenue, Suite 101 Bakersfield, CA 93311	661-332-7087
Anaergia Services, LLC www.anaergia.com	5780 Fleet Street, Suite 310 Carlsbad, CA 92008	760-436-8870
Babcock & Wilcox MEGTEC	830 Prosper Street, De Pere, WI 54115	920-337-1500
BioCNG, LLC www.biocng.us	8413 Excelsior Drive, Suite 160 Madison, WI 5371	630-410-7202
CDM Smith www.cdmsmith.com	600 Wilshire Boulevard, Suite 750 Los Angeles, CA 90017	213-457-2153
CGRS www.cgrs.com	1301 Academy Court, Fort Collins, CO 80524	800-288-2657
CH4 Biogas www.ch4biogas.com	30 Lakewood Circle N. Greenwich, CT 6830	203-869-1446
Clean Energy Fuels www.cleanenergyfuels.com	4675 MacArthur Court, Suite 800 Newport Beach, CA 92660	949-437-1000
Clear Horizons, LLC www.clearhorizonsllc.com	5070 N. 35th Street Milwaukee, WI 53209	414-831-1264
Colony Energy Partners www.colonyenergypartners.com	4940 Campus Drive, Suite C Newport Beach, CA 92660	949-752-7120
Digester Doc www.digesterdoc.com	7835 W. Mossy Cup St. Boise, ID 83709	208-278-2651

DMT Clear Gas Solutions www.dmt-cgs.com	19125 SW 125th Court Tualatin, OR 97062	503-379-0147
EcoCorp www.ecocorp.com	1211 S. Eads Street Arlington, VA 22202	703-979-4999
Eisenmann Corporation www.eisenmann.com	150 East Dartmore Drive Crystal Lake, IL 60014	815-455-4100
Energy Systems Group www.energysystemsgroup.com	4655 Rosebud Lane, Utility Services Business Unit Newburgh, IN 47630	812-492-3703
Enource, LLC www.enource.com	1403 Azalea Bend Sugar Land, TX 77479	832-449-8478
Entegris www.entegris.com	129 Concord Road, Billerica, MA 01821	978-436-6500
EnviTec-Biogas USA www.envitec-biogas.com	7 Fennell Street, Skaneateles, NY 13152	585-802-0174
FirmGreen www.firmgreen.com	2901 West Coast Highway, Suite 200 Newport Beach, CA 92663	949-270-2941
Generon IGS www.generon.com	16250 Tomball Parkway, Houston, TX 77086	713-937-5200
Guild Associates, Inc. www.guildassociates.com	5750 Shier-Rings Road Dublin, OH 43016	614-798-8215
Haldor Topsoe www.topsoe.com	770 The City Drive, Suite 8400 Orange, CA 92868	714-621-3800
Harveset Power www.harvestpower.com	221 Crescent Street, Suite 402 Waltham, MA 2453	781-314-9500
Hitachi Zosen Inova USA, LLC www.hz-inova.com	3930 E. Jones Bridge Road, Suite 200 Norcross, GA 30092	678-987-2500
John Zink Hamworthy Combustion www.johnzink.com	11920 East Apache Street Tulsa, OK 74105	918-234-1800
Northern Biogas www.northernbiogas.com	PO Box 643 Fond du Lac, WI 54936	920-948-3216
PlanET Biogas USA www.planet-biogas-usa.com	5937 State Route 11 Homer, NY 13077	877-266-0994
PCL Industrial Services, Inc. www.pcl.com	1500 South Union Avenue Bakersfield, CA 93307	661-835-4440
Prometheus Energy www.prometheusenergy.com	10370 Richmond Avenue, Suite 450 Houston, TX 77042	832-456-6500
Ross Group www.withrossgroup.com	510 E. 2nd Street Tulsa, OK 74120	918-234-7675
SCS Engineers www.scsengineers.com	3900 Kilroy Airport Way, Suite 100 Long Beach, CA 90806	562-426-9544

Tetra Tech www.tetratech.com	3475 East Foothill Boulevard Pasadena, CA 91107	703-387-2117
TMC Fluid Systems, Inc. www.tmcfluidsystems.com	13217 Jamboree Road, Suite 482 Tustin, CA 92782	949-269-1472
True North Renewable Energy, LLC www.tnrenewableenergy.com	2390 E. Camelback Road, Ste 203 Phoenix, AZ 85016	602-476-5800
Unison Solutions, Inc. www.unisonsolutions.com	5451 Chavenelle Road Dubuque, Iowa 52002	563-585-0967
U.S. Gain www.usgain.com/what-we-do/rng-alternative-fuel-source	425 Better Way Appleton, WI 54915	920-243-5856
Veolia technomaps.veoliawatertechnologies.com/biothane-anaerobic-technologies/en/	6981 North Park Drive, Suite 600 Pennsauken, NJ 08109	856-438-1776
Western Biogas Systems www.firmgreen.com	2522 Chambers Road, Suite 100 Tustin, CA 92780	866-511-1420
Xebec Adsorption USA www.xebecinc.com	14090 Southwest Freeway, Suite 300 Sugarland, TX 77478	604-362-7297
Xergi www.xergi.com	9825 NW Maring Drive Portland, OR 97229	503-830-4086

CANADA

Air Liquide Advanced Separations www.airliquideadvancedseparations.com/our-membranes/biogas	Suite 500, 140-4 Ave SW Calgary, AB T2P 3N3	403-585-2620
Greenlane Biogas www.greenlanebiogas.com	102-4238 Lozelis Avenue Burnaby, British Columbia, V5A OC4	604-805-8532
PlanET Biogas Solutions www.planet-biogas.ca	56-113 Cushman Road St. Catharines, Ontario, L2M 6S9	905-935-1969
Xebec www.xebecinc.com	730 Boulevard Industriel Blainville, Quebec, Canada, J7C 3V4	450-979-8700

EUROPE

AUSTRIA

Gastechnik Himmel www.gt-himmel.com	Industriestrasse 3 2100 Korneuburg, Austria	+43 2262 / 613 69

DENMARK

Ammongas www.ammongas.dk	Ejby Mosevej 5 2600 Glostrup, Denmark	+45 69134084

Biogasclean www.biogasclean.com	Egelundsvej 18 DK-5260 Odense S, Denmark	+45 41964569
Gemidan Ecogi www.gemidan.dk/en/frontpage/	Øster Dahl Hjallerupvej 36 DK-9320 Hjallerup, Denmark	+45 98283000
LSM Pumps www.lsmpumps.com	Sigenvej 7 DK-9760 Vraa, Denmark	+45 51247543
Nature Energy www.natureenergy.dk	Ørbækvej 260 DK-5220 Odense SØ, Denmark	+45 63156451
Renew Energy www.renewenergy.dk/en	Kullinggade 31E DK-5700 Svendborg, Denmark	+45 62220001

FINLAND

Metener www.metener.fi	Vaajakoskentie 104 41310 Leppävesi, Finland	+358 50 591 3861

FRANCE

Air Liquide Advanced Separations www.airliquideadvancedseparations.com/our-membranes/biogas	2 Rue de Clemenciere 38360 Sassenage, France	+33 06 26 80 28 31
Cryostar www.cryostar.com	2 Rue de l'Industrie ZI BP 48 68220 Hesingue, France	+33 389 70 27 27
Prodeval www.prodeval.eu	Rovaltain, Parc du 45ème Parallèle - 11 rue Olivier de Serres, 26300 Châteauneuf-sur-Isère, France	+33 0 4 75 40 37 37

GERMANY

BebraBiogas www.bebra-biogas.com	Kurze Muhren 1 20095 Hamburg, Germany	+49 231 9982 700
Carbotech www.carbotech.info	Natorpstrabe 27 45139 Essen, Germany	+49 201 50709-300
Eisenmann www.eisenmann.com	Tubinger Str. 81 71032 Boblingen, Germany	+49 7031 78-0
EnviTec Biogas www.envitec-biogas.com	BoschstraBe 2 48369 Saerbeck, Germany	+49 (0) 2574 / 8888-0
ETW Energietechnik www.etw-energy.com	Ferdinand-Zeppelin-Str. 19 47445 Moers, Germany	+49 2841 9990 0
HAASE Energietechnik www.haase.de	OderstraBe 76 24539 Neumunster, Germany	+49 4321 / 878-0

Mahler www.mahler-ags.com	Inselstr. 140 70327 Stuttgart, Germany	+49 (7 11) 87030 - 0
Mainsite Technologies www.mainsite-technologies.de	Industrie Center Obernburg 63784 Obernburg, Germany	+49 (0) 6022 / 81-3366
Schwelm Anlagentechnik www.schwelm-at.de	Hattinger StraBe 10-12 (oder Eisenwerkstrasse) D-58332 Schwelm, Germany	+49 2336 / 809 - 0
Strabag www.strabag-umweltanlagen.com	Vogelsanger Weg 111 40470 Düsseldorf, Germany	+49 211 6104-50
Weltec Biopower GmbH www.weltec-biopower.com	Zum Langenberg 2 49377 Vechta, Germany	+49 4441 999780

NETHERLANDS

DMT www.dmt-et.nl	Yndustrywei 3, 8501 SN Joure, The Netherlands	+31 (0) 513 636 789
Gas Treatment Services www.gastreatmentservices.com	Timmerfabriekstraat 12 2861 GV Bergambacht, The Netherlands	+31 182-621890

NORWAY

Memfoact www.memfoact.no	Industriveien 39 E 7080 Heimdal, Norway	+47 47 971 69 635

PORTUGAL

Sysadvance www.sysadvance.com	4470-605 Moreira da Maia Portugal	+351 229 436 790

SPAIN

HERA CleanTech www.heracleantech.com	Parc Tecnològic de Cerdanyola del Vallès, Ronda Can Fatjo nº 9, edifici C, (Primera Planta) 08290 Cerdanyola, Barcelona	+33 (0) 6 4858 8458
RosRoca www.rosroca.com	PCITAL Gardeny, Edificio H2, Planta 2a 25003 Lleida, Spain	+34 973 508 100

SWEDEN

Biofrigas www.biofrigas.se	J.A. Wettergrensgata 7 SE-421 30 Västra Frölunda, Sweden	+46 708-183807

Biosling www.biosling.se	Marknadsvägen 202 981 91 Jukkasjärvi, Sweden	+46 0980-23 000
Econet www.econetgroup.se	Singelgatan 12, 212 28 Malmö, Sweden	+46 0 4010 5070
Malmberg Water www.malmberg.se	SE-296 85 AHUS, Sweden	+46 44 780 18 00
Neo-Zeo www.neo-zeo.com	Svante Arrhenius vag 21 B 10691 Stockholm, Sweden	+46 7 6219 9731
Purac Puregas www.lackebywater.se	Torsasgatan 5 E 392 39 Kalmar, Sweden	+46 480 38 100

SWITZERLAND

Acrona Projects www.acrona-group.com	Avenue des sports 42 CH-1400 Yverdon-les-Bains, Switzerland	+41 (0) 78 723 04 02

UNITED KINGDOM

Gasrec www.gasrec.co.uk	Paddington Station 19 Eastbourne Terrace London, W2 6LG, United Kingdom	+44 0203 0046888
Hamworthy www.hamworthy.com	Fleets Corner, Poole, Dorset, BH17 055, United Kingdom	+46 0980-23 000

Information related to this list is available at www.socalgas.com/rg. To inquire about being added to this list, please send an e-mail to MarketDevelopment@SoCalGas.com.

The information contained herein is made available solely for informational purposes. Although SoCalGas has used reasonable efforts to assure the accuracy of the information at the time of its inclusion, no express or implied representation is made that it is free from error or suitable for any particular use or purpose. This list is not exhaustive, and there are numerous qualified vendors not listed herein that can provide products and services needed for the construction and operation of biogas conditioning and upgrading facilities. Vendors are listed alphabetically, and the order of listing implies no preference of any particular vendor by SoCalGas. SoCalGas does not recommend or endorse the products or services of any particular vendor listed herein, or represent that the particular products or services provided by such vendor are fit for any particular purpose or use. By publishing this list, SoCalGas is not acting in an advisory capacity and does not assume any responsibility for use of the list by you. You should discuss decisions related to this subject with your own advisors and experts.

SoCalGas™

Rule No. 30 Sheet 1

TRANSPORTATION OF CUSTOMER-OWNED GAS

The general terms and conditions applicable whenever the Utility System Operator transports customer-owned gas, including wholesale customers, the Utility Gas Procurement Department, other end-use customers, aggregators, marketers and storage customers (referred to herein as “customers") over its system are described herein.

A. General

1. Subject to the terms, limitations and conditions of this rule and any applicable CPUC authorized tariff schedule, directive, or rule, the customer will deliver or cause to be delivered to the Utility and accept on redelivery quantities of gas which shall not exceed the Utility's capability to receive or redeliver such quantities. The Utility will accept such quantities of gas from the customer or its designee and redeliver to the customer on a reasonably concurrent basis an equivalent quantity, on a therm basis, to the quantity accepted.

2. The customer warrants to the Utility that the customer has the right to deliver the gas provided for in the customer's applicable service agreement or contract (hereinafter "service agreement") and that the gas is free from all liens and adverse claims of every kind. The customer will indemnify, defend and hold the Utility harmless against any costs and expenses on account of royalties, payments or other charges applicable before or upon delivery to the Utility of the gas under such service agreement.

3. The point(s) where the Utility will receive the gas into its intrastate system (point(s) of receipt, as defined in Rule No. 1) and the point(s) where the Utility will deliver the gas from its intrastate system to the customer (point(s) of delivery, as defined in Rule No. 1) will be set forth in the customer's applicable service agreement. Other points of receipt and delivery may be added by written amendment thereof by mutual agreement. The appropriate delivery pressure at the point(s) of T
delivery to the customer shall be that existing at such point(s) within the Utility's system or as T
specified in the service agreement.

B. Quantities

1. The Utility shall as nearly as practicable each day redeliver to customer and customer shall accept, a like quantity of gas as is delivered by the customer to the Utility on such day. It is the intention of both the Utility and the customer that the daily deliveries of gas by the customer for transportation hereunder shall approximately equal the quantity of gas which the customer shall receive at the point(s) of delivery. However, it is recognized that due to operating conditions either (1) in the fields T
of production, (2) in the delivery facilities of third parties, or (3) in the Utility's system, deliveries into and redeliveries from the Utility's system may not balance on a day-to-day basis. The Utility and the customer will use all due diligence to assure proper load balancing in a timely manner.

(Continued)

B. Quantities (Continued)

2. The gas to be transported hereunder shall be delivered and redelivered as nearly as practicable at uniform hourly and daily rates of flow. The Utility may refuse to accept fluctuations in excess of ten percent (10%) of the previous day's deliveries, from day to day, if in the Utility's opinion receipt of such gas would jeopardize other operations. Customers may make arrangements acceptable to the Utility to waive this requirement.

3. The Utility does not undertake to redeliver to the customer any of the identical gas accepted by the Utility for transportation, and all redelivery of gas to the customer will be accomplished by substitution on a therm-for-therm basis.

4. Transportation customers, including the Utility Gas Procurement Department, wholesale customers, contracted marketers, and Core Transport Agents (CTAs) will be provided monthly balancing services in accordance with the provisions of Schedule No. G-IMB.

C. Electronic Bulletin Board

1. The Utility prefers and encourages customers, including the Utility Gas Procurement Department, to use Electronic Bulletin Board (EBB) as defined in Rule No. 1 to submit their transportation nominations to the Utility. Imbalance trades, Scheduled Quantity Trades, Producer Daily Delivery Trades, and Payback Imbalance Trades are to be submitted through the EBB. Monthly Imbalance Trades may also be submitted by means of the Imbalance Trading Agreement Form (Form 6544). Use of EBB is not mandatory for transportation only customers. N | N

2. Transportation nominations may be submitted manually or through EBB.

D. Operational Requirements

1. Customer Representation

   The customer must provide to the Utility the name(s) of any agents ("Agent") used by the customer for delivery of gas to the Utility for transportation service hereunder and their authority to represent customer.

   A customer may choose only one of the following gas supply arrangements: 1) one Contracted Marketer, 2) one or multiple Agents (in addition to a Contracted Marketer if desired), or 3) itself for purposes of nominating to its end-use account (OCC).

(Continued)

(Continued)

D. Operational Requirements (Continued)

2. Receipt Points

Utility accepts nominations from transportation customers or their representatives at the following Receipt Points into the SoCalGas system, as referenced in Schedule No. G-BTS*:

- El Paso Pipeline at Blythe (Southern Transmission Zone)
- North Baja Pipeline at Blythe (Southern Transmission Zone)
- Transportadora de Gas Natural de Baja California at Otay Mesa (Southern Transmission Zone)
- Kern River Pipeline and Mojave Pipeline (Wheeler Transmission Zone)
- PG&E at Kern River Station (Wheeler Transmission Zone)
- Occidental of Elk Hills at Gosford (Wheeler Transmission Zone)
- Transwestern Pipeline at North Needles (Northern Transmission Zone)
- Transwestern Pipeline at Topock (Northern Transmission Zone)
- El Paso Pipeline at Topock (Northern Transmission Zone) D
- Kern River Pipeline and Mojave Pipeline at Kramer Junction (Northern Transmission Zone)
- Line 85 (California Supply)
- North Coastal (California Supply)
- Other (California Supply)
- Storage

* Additional Receipt Points will be added as they are established in the future.

3. Backbone Transmission Capacity

Each day, Receipt Point and Backbone Transmission Zone capacities will be set at their physical operating maximums under the operating conditions for that day. The Utility will schedule nominations for each Receipt Point and Backbone Transmission Zone to the maximum operating capacity of that individual Receipt Point or Backbone Transmission Zone. The maximum operating capacity is defined as the facility design or contractual limitation to deliver gas into the Utility's system adjusted for operational constraints (i.e. maintenance, localized restrictions, and upstream delivery pressures) as determined each day.

The NAESB elapsed pro rata rules require that the portion of the scheduled quantity that would have theoretically flowed up to the effective time of the intraday nomination be confirmed, based upon a cumulative uniform hourly quantity for each nomination period affected. As such, the scheduled quantities for each shipper are subject to change in the Intraday 1 Cycle, the Intraday 2 Cycle, and the Intraday Cycle 3. However, each shipper's resulting scheduled quantity for the Gas Day will be no less than the elapsed prorated scheduled quantity for that shipper.

(Continued)

D. Operational Requirements (Continued)

3. Backbone Transmission Capacity (Continued)

Each day, the Utility will use the following rules to confirm nominations to the Receipt Point and Backbone Transmission Zone maximum operating capacities. The Utility will also use the following rules to confirm nominations to the system capacity limitation as defined in Section F for OFO events during the Intraday 1, Intraday 2, and Intraday 3 cycles; and during the Intraday 3 cycle when an OFO event is not called and nominations exceed system capacity. D,N

Confirmation Order:

- Nominations using Firm Primary backbone transportation rights will be first; pro-rated if over-nominated*.
- Nominations using Firm Alternate backbone transportation rights within the associated transmission zone will be second (“Firm Alternate Within-the-Zone”); pro-rated if over-nominated.
- Nominations using Firm Alternate backbone transportation rights outside the associated transmission zone will be third (“Firm Alternate Outside-the-Zone”); pro-rated if over-nominated.
- Nominations using Interruptible backbone transportation rights will be fourth, pro-rated if over-nominated.
- Southern Transmission Receipt Points will not be reduced in any cycle below 110% of the Southern System minimum flowing supply requirement established by the Gas Control Department.

Bumping Rules:

- Firm Primary rights can “bump” any Firm Alternate scheduled quantities through the Evening Cycle.
- Firm Alternate Within-the-Zone rights can “bump” Firm Alternate Outside-the-Zone scheduled quantities through the Evening Cycle.
- Firm Primary and any Firm Alternate can “bump” interruptible scheduled quantities through the Intraday 2 Cycle subject to the NAESB elapsed pro-rata rules.
- Bumping will not be allowed in the Intraday 3 Cycle.

* If the available firm capacity at a particular receipt point or within a particular transmission zone is less than the firm capacity figures stated in Schedule No. G-BTS, scheduling of firm backbone transportation capacity nominations will be pro rata within each scheduling cycle. Any nominations of firm backbone transportation rights acquired through the addition of Displacement Backbone Transmission Capacity facilities will be reduced pro rata to zero at the applicable receipt point or within the applicable transmission zone prior to other firm backbone transportation rights nominations being reduced.

(Continued)

(Continued)

D. Operational Requirements (Continued)

3. Backbone Transmission Capacity (Continued)

Priority Rules:

a. Firm primary scheduled quantities in the Evening Cycle will have priority over a new firm primary nomination made in the Intraday 1 Cycle.
b. Firm Alternate Inside-the-Zone scheduled quantities in the Evening Cycle will have priority over a new Firm Alternate Inside-the-Zone nomination made in the Intraday 1 Cycle.
c. Firm Alternate Outside-the-Zone scheduled quantities in the Evening Cycle will have priority over a new Firm Alternate Outside-the-Zone nomination made in the Intraday 1 Cycle.
d. Interruptible scheduled quantities in the Evening Cycle will have priority over a new Interruptible nomination made in the Intraday 1 Cycle.
e. This same structure will be applied in going from Intraday 1 Cycle (Cycle 3) to Intraday 2 Cycle (Cycle 4) to Intraday 3 Cycle (Cycle 5). However, this hierarchy will not affect Intraday 4 Cycle (Cycle 6) nominations or the elapsed pro-rata rule.

4. Storage Service Capacity

Each day, storage injection and withdrawal capacities will be set at their physical operating maximums under the operating conditions for that day and posted on the Utility's EBB. *Injection nominations will be held to the injection capacity specified in the Operational Flow Order (OFO) calculation on the EBB in every flowing cycle regardless of OFO status.** The Utility will use the following rules to limit the nominations to the storage maximums. D

As necessary, available withdrawal or injection capacities will be prorated to the core and daily balancing functions based on the maximum authorized withdrawal or injection capacities, as detailed in Decision (D.) 20-02-045. D,N N D,N

- Nominations using Firm storage rights will have the highest priority, pro-rated, if necessary to the available storage capacity. D,N
- All other nominations using Interruptible storage rights will have the lowest priority, pro-rated if over-nominated based on the daily volumetric price paid.
- On low OFO days the volume of interruptible withdrawal will be cut in half relative to the calculation on a non-OFO day. If interruptible nominations immediately prior to the low OFO were above this level, then they will be held constant through the low OFO.
- Firm storage rights can "bump" interruptible scheduled storage quantities through the Intraday 3 cycle.

Notice to bumped parties will be provided via the Transactions module in EBB. Bumping is subject to the NAESB elapsed prorata rules.

(Continued)

D. Operational Requirements (Continued)

5. Off-System Delivery (OSD) Service

For each flow date, the Utility will determine the quantity of capacity available for off-system deliveries. The quantity will include that available via physical redelivery from the Utility system along with displacement of forward haul flowing supplies. For each nomination cycle, the Utility customers who have contracted with the Utility for off-system delivery service may submit a nomination for such service pursuant to Schedule No. G-OSD and Section D.6. "Nominations" below, for deliveries to the PG&E system and to the Utility Transmission system's interconnection points with all interstate and international pipelines, but excluding California-produced gas supply lines.

The following rules will be used in scheduling of Off-System Delivery Services:

- Nominations using Firm OSD rights will have first priority; pro-rated if over-nominated.
- Nominations using Interruptible OSD rights will have second priority; pro-rated if over-nominated.
- Firm OSD rights can "bump" Interruptible OSD scheduled quantities through the Intraday 2 Cycle, subject to the NAESB elapsed pro-rata rules.
- Bumping of Interruptible OSD rights by Firm OSD rights will not be allowed in the Intraday 3 Cycle.
- Both Firm and Interruptible OSD rights, at any Delivery Point, can be reduced in any cycle, D
including during curtailment events, (subject to the NAESB elapsed pro rata rules) if, in the N
sole judgment of the Utility, the discontinuation or reduction of OSD service at that D,N
Delivery Point would diminish the need for the Utility to bring additional gas into the D,N
Utility's system at an additional cost or reduce the level of curtailment to any Utility N
customer. N
- Reduction of Interruptible OSD nominations at any Delivery Point will be prorated at that D
particular Delivery Point.
- Reduction of Firm OSD nominations at any Delivery Point will be prorated at that particular D
Delivery Point.

(TO BE INSERTED BY UTILITY) ISSUED BY (TO BE INSERTED BY CAL. PUC)
ADVICE LETTER NO. 5050 **Dan Skopec** DATE FILED Oct 25, 2016
DECISION NO. 16-07-008 Vice President EFFECTIVE Nov 1, 2016
6C15 Regulatory Affairs RESOLUTION NO.

D. Operational Requirements (Continued)

6. Nominations

The customer shall be responsible for submitting gas service nominations to the Utility no later than the deadlines specified below.

Each nomination shall include all information required by the Utility's nomination procedures. Nominations received by the Utility will be subject to the conditions specified in the service agreements with the Utility. The Utility may reject any nomination not conforming to the requirements in these rules or in applicable service agreements. The customer shall be responsible for making all corresponding upstream nomination/confirmation arrangements with the interconnecting pipeline(s) and/or operator(s).

Evening and Intraday nominations may be used to request an increase or decrease to scheduled volumes or a change to receipt or delivery points.

Intraday nominations do not roll from day to day.

Nominations submitted in any cycle will automatically roll to subsequent cycles for the specified flow date and from day-to-day through the end date or until the end date is modified by the nominating entity.

Nominations may be made in the following manner:

FROM	TO	
Pipeline/CA Producer	Backbone Transportation Service Contract	
Backbone Transportation Service Contract	End User, Contracted Marketer, CTA	
Backbone Transportation Service Contract	Citygate Pool Account	
Backbone Transportation Service Contract	Storage Account	
Citygate Pool Account	End User, Contracted Marketer, CTA	
Citygate Pool Account	Citygate Pool Account	
Storage Account	End User, Contracted Marketer, CTA	
Citygate Pool Account	Storage Account	L
Storage Account	Citygate Pool Account	|
Storage Account	Storage Account	|
Storage Account	Off-System Delivery Contract	|
Citygate Pool Account	Off-System Delivery Contract	|
End User, Contracted Marketer, CTA	Storage Account	L

(Continued)

(Continued)

D. Operational Requirements (Continued)

6. Nominations (Continued)

FROM	TO (Continued)	
Off-System Delivery Contract	PG&E Pipeline (at Kern River Station)	
Off-System Delivery Contract	Mojave Pipeline (at Wheeler Ridge)	
Off-System Delivery Contract	Mojave Pipeline (at Kramer Junction)	
Off-System Delivery Contract	Kern River Pipeline (at Wheeler Ridge)	
Off-System Delivery Contract	Kern River Pipeline (at Kramer Junction)	D
Off-System Delivery Contract	Transwestern Pipeline (at North Needles)	
Off-System Delivery Contract	Transwestern Pipeline (at Topock)	
Off-System Delivery Contract	El Paso Pipeline (at Topock)	
Off-System Delivery Contract	El Paso Pipeline (at Blythe)	
Off-System Delivery Contract	North Baja Pipeline (at Blythe)	
Off-System Delivery Contract	Transportadora de Gas Natural de Baja California (at Otay Mesa)	
Receipt Point Pool Account	Receipt Point Pool Account	
Receipt Point Pool Account	Backbone Transportation Contract	

7. Timing

All times referred to below are in Pacific Clock Time. Requests for deadline extensions may be granted for 15 minutes only if request is made prior to the deadlines shown below.

Timely Cycle

Transportation nominations submitted via EBB for the Timely Nomination cycle must be received by the Utility by 11:00 a.m. one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 10:00 a.m. one day prior to the flow date. Timely nominations will be effective at 7:00 a.m. on the flow date.

Evening Cycle

Nominations submitted via EBB for the Evening Nomination cycle must be received by the Utility by 4:00 p.m. one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 3:00 p.m. one day prior to the flow date. Evening nominations will be effective at 7:00 a.m. on the flow date.

(Continued)

D. Operational Requirements (Continued)

7. Timing (Continued)

Intraday 1 Cycle

Nominations submitted via EBB for the Intraday 1 Nomination cycle must be received by the Utility by 8:00 a.m. on the flow date. Nominations submitted via fax must be received by the Utility by 7:00 a.m. on the flow date. Intraday 1 nominations will be effective at 12:00 p.m. the same day.

Intraday 2 Cycle

Nominations submitted via EBB for the Intraday 2 Nomination cycle must be received by the Utility by 12:30 p.m. on the flow date. Nominations submitted via fax must be received by the Utility by 11:30 a.m. on the flow date. Intraday 2 nominations will be effective at 4:00 p.m. the same day.

Intraday 3 Cycle

Nominations submitted via EBB for Intraday 3 Nomination cycle must be received by the Utility by 5:00 p.m. on the flow date. Nominations submitted via fax must be received by the Utility by 4:00 p.m. on the flow date. Intraday 3 nominations will be effective at 8:00 p.m. the same day.

Intraday 4 Cycle

Nominations submitted via EBB for the Intraday 4 Nomination cycle must be received by the Utility
by 9:00 p.m. Pacific Clock Time one calendar day after the flow date. Nominations submitted via D,N
fax must be received by the Utility by 8:00 p.m. Pacific Clock Time one calendar day after the flow D,N
date. N

Intraday 4 nominations are available only for firm nominations relating to the injection of existing flowing supplies into a storage account or for firm nominations relating to the withdrawal of gas in storage to meet an identified customer's usage. A customer may make Intraday 4 nominations from a third-party storage provider that is directly connected to the Utility's system or from the Utility's storage, subject to the storage provider or the Utility being able to deliver or accept the daily quantity nominated for Intraday 4. Third-party storage providers will be treated on a comparable basis with the Utility's storage facilities to the extent that it can provide the equivalent service and operations.

Scheduled Quantity Trading

Customers may trade scheduled quantities for any Gas Day.

A scheduled quantity trade must occur between a Buyer End-use contract and Seller End-use contract. The Buyer End-use contract must be different from the Seller End-use contract.

D. Operational Requirements (Continued)

Scheduled Quantity Trading (Continued)

Customers may post scheduled quantity trades between the time a Gas Day is finished being processed by the Utility and 9:00 PM Pacific Clock Time one business day following the Intraday 4 nomination deadline. Utility will not grant any extensions beyond this deadline. N N

After Utility confirms a scheduled quantity trade, it may only be voided at the discretion of Utility on behalf of the Buyer and Seller involved. The Buyer and Seller must send an email to GasScheduling@socalgas.com by 3:00 PM Pacific Clock Time on the second day of the month after the month of the Gas Day.

Customers may not enter into a trade that results in negative scheduled quantities. If negative scheduled quantities result due to reallocations, void trades, or other circumstances, Utility shall contact the Buyer and Seller of the trade to resolve the issue.

Daily Deliveries Trading (For California Producers)

California Producers may trade daily deliveries for any Gas Day.

California Producers either have a California Producer Operational Balancing Agreement (CPOBA) or a non-CPOBA.

A daily delivery trade must occur between 1) a Buyer CPOBA contract and a Seller CPOBA contract; or 2) a Buyer non-CPOBA contract and Seller non-CPOBA contract.

For CPOBA contracts, California Producers may post daily delivery trades between the time a Gas Day is finished being processed by the Utility and 9:00 PM Pacific Clock Time one business day following the Intraday 4 nomination deadline. Utility will not grant any extensions beyond this deadline. N D,N D,N

For non-CPOBA contracts, California Producers may post daily delivery trades between the time a Gas Day is finished being processed by the Utility and 9:00 PM Pacific Clock Time one business day following the Intraday 4 nomination deadline. Utility will not grant any extensions beyond this deadline. T D,N

After Utility confirms a daily delivery trade, it may only be voided at the discretion of Utility on behalf of the Buyer and Seller involved. The Buyer and Seller must send an email to GasScheduling@socalgas.com by 3:00 PM Pacific Clock Time on the second day of the month after the month of the Gas Day.

L

(Continued)

D. Operational Requirements (Continued)

Daily Deliveries Trading (For California Producers) (Continued)

California Producer may not enter into a trade that puts its Daily Operational Imbalance position into OFO penalty. If a California Producer is outside of its daily OFO tolerance, California Producer may not enter into a trade that increases its OFO imbalance position. L | L

California Producers may not enter into a trade that results in negative daily deliveries. If negative daily deliveries result due to reallocations, void trades, or other circumstances, Utility shall contact the Buyer and Seller of the trade to resolve the issue.

Payback Imbalance Trading (For California Producers with CPOBA)

For CPOBA contracts, California Producers may trade Cumulative Operational Imbalances during a payback period (payback imbalance trade) subject to the CPOBA.

A payback imbalance trade must occur between a Buyer CPOBA contract and a Seller CPOBA contract. At least one of the CPOBA contracts must be in a payback period.

California Producers may post payback imbalance trade once a CPOBA is in a payback period.

After Utility confirms a payback imbalance trade, it may only be voided at the discretion of Utility on behalf of the Buyer and Seller involved. The Buyer and Seller must send an email to GasScheduling@socalgas.com by 3:00 PM Pacific Clock Time on the second day of the month after the month of the Gas Day.

8. Confirmation and Ranking Process

A ranking must be received by the Utility at the time the nomination or the confirmation is submitted. The nominating party will rank its supplies and the confirming party will rank its markets. The Utility will then balance the pipeline system using the "lesser of" rule and the rankings submitted.

The ranking will automatically roll from cycle-to-cycle and day-to-day until the nomination end date, unless modified by the nominating entity.

If no ranking is submitted at the time the nomination is submitted, the Utility will assign the lowest ranking to the nomination.

L

(Continued)

D. Operational Requirements (Continued)

8. Confirmation and Ranking Process (Continued) T

The Utility will compare the nominations received for each transaction and the corresponding confirmation. If the two quantities do not agree, the "lesser of" the two quantities will be the quantity scheduled by the Utility. Subject to the Utility receiving notification of confirmed transportation from the applicable upstream pipeline(s) and/or operator(s), the Utility will provide scheduled quantities on EBB. L

9. As between the customer and the Utility, the customer shall be deemed to be in control and possession of the gas to be delivered hereunder and responsible for any damage or injury caused thereby until the gas has been delivered at the point(s) of receipt. The Utility shall thereafter be deemed to be in control and possession of the gas after delivery to the Utility at the point(s) of receipt and shall be responsible for any damage or injury caused thereby until the same shall have been redelivered at the point(s) of delivery, unless the damage or injury has been caused by the quality of gas originally delivered to the Utility, for which the customer shall remain responsible.

10. Any penalties or charges incurred by the Utility under an interstate or intrastate supplier contract as a result of accommodating transportation service shall be paid by the responsible customer.

11. Customers receiving service from the Utility for the transportation of customer-owned gas shall pay any costs incurred by the Utility because of any failure by third parties to perform their obligations related to providing such service.

E. Interruption of Service

1. The customer's transportation service priority shall be established in accordance with the definitions of Core and Noncore service, as set forth in Rule No. 1, and the provisions of Rule No. 23, Continuity of Service and Interruption of Delivery. If the customer's gas use is classified in more than one service priority, it is the customer's responsibility to inform the Utility of such priorities applicable to the customer's service. Once established, such priorities cannot be changed during a curtailment period.

2. The Utility shall have the right, without liability, to interrupt the acceptance or redelivery of gas whenever it becomes necessary to test, alter, modify, enlarge or repair any facility or property comprising the Utility's system or otherwise related to its operation. When doing so, the Utility will try to cause a minimum of inconvenience to the customer. Except in cases of unforeseen emergency, the Utility shall give a minimum of ten (10) days advance written notice of such activity.

F. Nominations in Excess of System Capacity

1. In the event customers fail to adequately reduce their transportation nominations, the Utility shall reduce the confirmed receipt point access nominations as defined in Section D.

(Continued)

(Continued)

G. Operational Flow Orders and Emergency Flow Orders

1. Operational Flow Order (OFO)

a. The Utility System Operator's protocol for declaring an Operational Flow Order (OFO) is described in Rule No. 41. All OFO declarations will be identified by stage that will specify a Daily Imbalance Tolerance and Noncompliance Charge per the table below. The daily balancing standby rate is not applicable to High OFOs. Pursuant to D.19-05-030, this OFO Noncompliance Charge structure shall remain in effect until October 31, 2021, unless modified by a subsequent Commission decision. L

Effective June 1 – September 30

Stage	Daily Imbalance Tolerance	Noncompliance Charge ($/therm)
1	Up to +/-25%	0.025
2	Up to +/-20%	0.10
3	Up to +/-15%	0.50
4	Up to +/-5%	0.50
5	Up to +/-5%	0.50 plus Rate Schedule G-IMB daily balancing standby rate
EFO	Zero	5.00 plus Rate Schedule G-IMB daily balancing standby rate

L

Effective October 1 – May 31

Stage	Daily Imbalance Tolerance[1]	Noncompliance Charge ($/therm)
1	Up to +/-25%	0.025
2	Up to +/-20%	0.10
3	Up to +/-15%	0.50
3.1	Up to +/-15%	1.00
3.2	Up to +/-15%	1.50
3.3	Up to +/-15%	2.00
4	Up to +/-10%	2.50
5	Up to +/-5%	2.50 plus Rate Schedule G-IMB daily balancing standby rate
EFO	Zero	5.00 plus Rate Schedule G-IMB daily balancing standby rate

[1] Negative daily imbalance tolerances for all stages are capped at up to -5% until Aliso Canyon's withdrawal capacity is available without constraint to the System Operator for load balancing.

L

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued)

1. Operational Flow Order (OFO) (Continued)

b. The OFO shall apply to all customers financially responsible for managing and clearing transportation imbalances (Balancing Agents), including wholesale customers, Contracted Marketers, core aggregators, California Gas Producers and the Utility Gas Procurement Department. L

c. The OFO period shall begin on the flow date(s) indicated by the Utility Gas Control Department. Generally an initial OFO event will start at Stage 1; however an OFO event may begin at any stage as deemed appropriate by the Utility Gas Control Department with the corresponding noncompliance charge.

d. An OFO will normally be ordered with at least twelve (12) hours notice prior to the beginning of the gas day, or as necessary as dictated by operating conditions. Charges for the first day of the OFO event will not be imposed if notice is given after *8:00 p.m.** Pacific Time the day prior to the start of the OFO event. L

e. OFO and EFO compliance and charges will be based on the following for determination of daily usage quantities:

i. For a Noncore End-Use Customer equipped with automated meter reading device (AMR) and SDG&E's Electric & Gas Fuel Procurement Department, compliance during an OFO will be based on actual daily metered usage, and the calculation after the OFO event of any applicable noncompliance charge will be based on actual daily metered usage.

ii. For a Noncore End-Use Customer with non-functioning AMR meters, compliance during an OFO or EFO will be based on the Customer's actual daily metered usage; or the estimated daily usage in accordance with Section C of SoCalGas Rule 14 will be substituted for the actual daily metered usage when actual metered usage is not available.

iii. For a Noncore End-Use Customer without AMR capability compliance during an OFO or EFO will be based on the Customer's MinDQ.

iv. For the Utility Gas Procurement Department, the Daily Usage for the Utility Gas Procurement Department will be used.

v. For core aggregators, their Daily Contract Quantity will be used as a proxy for daily usage.

L

(TO BE INSERTED BY UTILITY) ISSUED BY (TO BE INSERTED BY CAL. PUC)
ADVICE LETTER NO. 5681 Dan Skopec SUBMITTED Aug 28, 2020
DECISION NO. 19-08-002 Vice President EFFECTIVE Sep 1, 2020
14C7 Regulatory Affairs RESOLUTION NO.

G. Operational Flow Orders and Emergency Flow Orders (Continued)

1. Operational Flow Order (OFO) (Continued)

e. (Continued) L

vi. For a California Producer with an effective California Producer Operational Balancing Agreement, Form 6452, compliance with an OFO and EFO and calculation of any noncompliance charges will be based on the difference between scheduled receipts and measured receipts for each day of an event. OFO and EFO compliance for a California Producer with an existing non- California Producer Operational Balancing Agreement, Form 6452 access agreement will be treated consistent with the terms of that access agreement. L

f. If a Balancing Agent's OFO daily gas imbalance exceeds the applicable daily imbalance tolerance by 10,000 therms or less, the OFO, noncompliance charge will be zero. If the daily gas imbalance amount exceeds the daily imbalance tolerance by more than 10,000 therms, the Balancing Agent will be responsible for the full noncompliance charge; i.e. 10,000 therms will not be deducted from the daily gas imbalance that exceeds the daily imbalance tolerance.

g. The daily measurement quantity used to calculate the Noncompliance Charge for each OFO event will be the daily quantity recorded as of the month-end close of the applicable month.

h. *Low OFO noncompliance charges for the gas flow day will be waived when the confirmation process limiting nominations to system capacity cuts previously scheduled BTS nominations during any of the Intraday 1-3 Cycles.**

i. *SoCalGas will have the discretion to waive OFO noncompliance charges for an electric generation customer who was dispatched after the Intraday 1 (Cycle 3) nomination deadline in response to (1) a SoCalGas System Operator request to an Electric Grid Operator to reallocate dispatched electric generation load to help maintain gas system reliability and integrity, or (2) an Electric Grid Operator request to the SoCalGas System Operator to help maintain electric system reliability and integrity that can be accommodated by the SoCalGas System Operator at its sole discretion. For electric generators served by a contracted marketer, OFO noncompliance charges can be waived under this section only to the extent the contracted marketer nominates their electric generation customer's gas to the electric generation customer's Order Control Code.**

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued) L

2. Emergency Flow Order (EFO)

a. The Utility System Operator's protocol for declaring an Emergency Flow Order (EFO) is described in Rule No. 41.

b. During an EFO Customer usage must be less than or equal to scheduled supply for a gas day. EFOs will have a zero percent tolerance and a noncompliance charge of $5.00 plus the Schedule G-IMB Daily Balancing Standby Rate for each therm of usage in excess of scheduled supply.

c. The EFO shall apply to all customers financially responsible for managing and clearing transportation imbalances (Balancing Agents), including wholesale customers, Contracted Marketers, core aggregators, California Gas Producers and the Utility Gas Procurement Department.

d. When an EFO is in effect interruptible storage withdrawals are limited to one half of the capacity normally available for interruptible withdrawals. Interruptible storage withdrawal capacity is equal to Withdrawal Capacity minus confirmed firm storage withdrawal nominations minus withdrawal allocated to the balancing function.

e. Daily measurement quantities used to determine EFO compliance and charges are the same as those used to determine OFO compliance and charges.

f. The daily measurement quantity used to calculate the noncompliance charges for each EFO event will be the daily quantity recorded as of the month-end close of the applicable month. L

L

(Continued)

Rule No. 30 Sheet 17
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

G. Operational Flow Orders and Emergency Flow Orders (Continued) L

3. Information regarding the System Sendout, Withdrawal Capacity and Net Withdrawals will be made available to customers on a daily basis via the EBB.

4. If a wholesale customer so requests, the Utility will nominate firm storage withdrawal volumes on behalf of the customer to match 100% of actual usage assuming the customer has sufficient firm storage withdrawal and inventory rights to match the customer's supply and demand.

5. The Utility will accept intra-day nominations to increase deliveries.

6. In all cases, current rules for monthly balancing and monthly imbalance trading continue to apply. Quantities not in compliance with the Daily Imbalance Tolerance that are purchased at the daily balancing standby rate are credited toward the monthly 92% delivery requirements. Daily balancing charges remain independent of monthly balancing charges. Noncore daily balancing and monthly balancing charges go to the Purchased Gas Account (PGA). Net revenues from core daily balancing and monthly balancing charges go to the Noncore Fixed Cost Account (NFCA). Schedule No. G-IMB provides details on monthly and daily balancing charges.

H. Accounting and Billing

1. The customer and the Utility acknowledge that on any operating day during the customer's applicable term of transportation service, the Utility may be redelivering quantities of gas to the customer pursuant to other present or future service arrangements. In such an event, the Utility and customer agree that the total quantities of gas shall be accounted for in accordance with the provisions of Rule No. 23. If there is no conflict with Rule No. 23, the quantities of gas shall be accounted for in the following order:

   a. First, to satisfy any minimum quantities under existing agreements.

   b. Second, after complete satisfaction of (a), then to any supply or exchange service arrangements with the customer.

   c. Third, after the satisfaction of (a) and (b), then to any subsequently executed service agreement. L

L

(Continued)

H. Accounting and Billing (Continued) L

2. The customer agrees that it shall accept and the Utility can rely upon, for purposes of accounting and billing, the allocation made by customer's shipper as to the quality and quantity of gas, expressed both in Decatherm and therms, delivered at each point of receipt during the preceding billing period for the customer's account. If the shipper does not make such an allocation, the customer agrees to accept the quality and quantity as determined by the Utility. All quality and measurement calculations are subject to subsequent adjustment as provided in the Utility's tariff schedules or applicable CPUC rules and regulations. Any other billing correction or adjustment made by the customer or third party for any prior period shall be based on the rates or costs in effect when the event occurred and accounted for in the period they are reconciled.

3. The Utility shall render to the customer an invoice for the services hereunder showing the quantities of gas, expressed in therms, delivered to the Utility for the customer's account, at each point of receipt and the quantities of gas, expressed in therms, redelivered by the Utility for the customer's account at each point of delivery during the preceding billing period. The Customer shall pay such amounts due hereunder within nineteen (19) calendar days following the date such bill is mailed.

4. Both the Utility and the customer shall have the right at all reasonable times to examine, at its expense, the books and records of the other to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to service hereunder. The Utility and the customer agree to keep records and books of account in accordance with generally accepted accounting principles and practices in the industry.

I. Gas Delivery Specifications

1. The natural gas stream delivered into the Utility's system shall conform to the gas quality specifications as provided in any applicable agreements and contracts currently in place between the entity delivering such natural gas and the Utility at the time of the delivery. If no such agreement is in place, the natural gas shall conform to the gas specifications as defined below. L

L

I. Gas Delivery Specifications (Continued)

2. Gas delivered into the Utility's system for the account of a customer for which there is no existing contract between the delivering pipeline and the Utility shall be at a pressure such that the gas can be integrated into the Utility's system at the point(s) of receipt.

3. Gas delivered, except as defined in I.1 above, shall conform to the following quality specifications at the time of delivery:

   a. Heating Value: The minimum heating value is nine hundred and seventy (970) Btu (gross) per standard cubic foot on a dry basis. The maximum heating value is one thousand one hundred fifty (1150) Btu (gross) per standard cubic foot on a dry basis. T,R

   b. Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20 degrees F at delivery pressure.

   c. Hydrogen Sulfide: The gas shall not contain more than twenty-five hundredths (0.25) of one (1) grain of hydrogen sulfide, measured as hydrogen sulfide, per one hundred (100) standard cubic feet (4 ppm). The gas shall not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products in the gas stream.

   d. Mercaptan Sulfur: The gas shall not contain more than three tenths (0.3) grains of mercaptan sulfur, measured as sulfur, per hundred standard cubic feet (5 ppm).

   e. Total Sulfur: The gas shall not contain more than seventy-five hundredths (0.75) of a grain of total sulfur compounds, measured as sulfur, per one hundred (100) standard cubic feet (12.6 ppm). This includes COS and CS2, hydrogen sulfide, mercaptans and mono, di and poly sulfides.

   f. Carbon Dioxide: The gas shall not have a total carbon dioxide content in excess of three percent (3%) by volume.

   g. Oxygen: The gas shall not have an oxygen content in excess of two-tenths of one percent (0.2%) by volume, and customer will make every reasonable effort to keep the gas free of oxygen.

   h. Inerts: The gas shall not contain in excess of four percent (4%) total inerts (the total combined carbon dioxide, nitrogen, oxygen and any other inert compound) by volume.

(Continued)

I. Gas Delivery Specifications (Continued)

3. (Continued)

i. Hydrocarbons: For gas delivered at a pressure of 800 psig or less, the gas hydrocarbon dew point is not to exceed 45 degrees F at 400 psig or at the delivery pressure if the delivery pressure is below 400 psig. For gas delivered at a pressure higher than 800 psig, the gas hydrocarbon dew point is not to exceed 20 degrees F measured at a pressure of 400 psig.

j. Merchantability: The gas shall not contain dust, sand, dirt, gums, oils and other substances at levels that would be injurious to Utility facilities or that would cause gas to be unmarketable.

k. Hazardous Substances: The gas must not contain hazardous substances (including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins) at concentrations which would prevent or restrict the normal marketing of gas, be injurious to pipeline facilities, or which would present a health and/or safety hazard to Utility employees and/or the general public.

l. Delivery Temperature: The gas delivery temperature is not to be below 50 degrees F or above 105 degrees F.

m. Interchangeability: The gas shall have a minimum Wobbe Number of 1279 and shall not have a maximum Wobbe Number greater than 1385. The gas shall meet American Gas Association's Lifting Index, Flashback Index and Yellow Tip Index interchangeability indices for high methane gas relative to a typical composition of gas in the Utility system serving the area.

Acceptable specification ranges are:

* Lifting Index (IL)
  IL <= 1.06

* Flashback Index (IF)
  IF <= 1.2

* Yellow Tip Index (IY)
  IY >= 0.8

n. Liquids: The gas shall contain no liquids at or immediately downstream of the receipt point.

(TO BE INSERTED BY UTILITY) ISSUED BY (TO BE INSERTED BY CAL. PUC)
ADVICE LETTER NO. 5471 Dan Skopec SUBMITTED May 31, 2019
DECISION NO. 19-05-030 Vice President EFFECTIVE May 31, 2019
20C12 Regulatory Affairs RESOLUTION NO.

I. Gas Delivery Specifications (Continued)

4. The Utility, at its option, may refuse to accept any gas tendered for transportation by the customer or on his behalf if such gas does not meet the specifications at the time of delivery as set out in I. 2, I. 3, and J.5, as applicable.

5. The Utility will grant specific deviations to California production from the gas quality specifications defined in Paragraph I.3 above, if such gas will not have a negative impact on system operations. Any such deviation will be required to be filed through Advice Letter for approval prior to gas actually flowing in the Utility system.

6. The Utility will post on its EBB and/or general website information regarding the available real-time Wobbe Number of gas at identified operational locations on its system.

7. Gas monitoring and enforcement hardware and software including, but not limited to, a gas chromatograph and all related equipment, communications facilities and software, identified in Exhibit A to Schedule No. G-CPS, are required, and shall be installed at each interconnection meter site where a California Producer delivers natural gas into the Utility's gas transportation system. The gas chromatograph shall monitor non-hydrogen sulfide constituents in the gas delivered, and deny access to gas that does not comply with the gas specifications set forth in the Gas Delivery Specifications, Section I.1 or I.3 above. Compliance shall be assessed using the 4- to 8-minute monitoring interval adopted in D.07-08-029 and D.10-09-001.

8. The gas chromatograph and all related equipment and software, identified in Exhibit A to Schedule No. G-CPS, shall monitor and enforce the gas quality specifications, using the 4- to 8-minute monitoring interval adopted in D.07-08-029 and D.10-09-001. Access shall be denied by the Utility on a non-latching basis after a second consecutive monitoring interval results in an alarm for gas which exceeds the non-hydrogen sulfide specifications. The gas chromatograph and all related equipment and software shall also enable the Utility to remotely gather and retain gas quality and alarm data. Where additional measures are necessary to promote or enhance safety, SoCalGas may request a deviation from the aforementioned monitoring interval requirements established by the CPUC.

9. For California Producers currently delivering gas into the Utility's transportation system without a gas chromatograph and all related equipment and software in place, as required in Rule No. 39, non-hydrogen sulfide constituents of gas will, on an interim basis, continue to be monitored and access denied under the methods currently in place, until such time as a gas chromatograph and all related equipment and software are installed and operational, subject to Rule No. 39 conditions.

(Continued)

J. Renewable Gas Delivery Specifications D,N

1. Renewable Gas delivered, except as defined in Section I.1, must meet the gas quality specifications set out in Section I and the renewable gas-specific specifications set out in the Standard Renewable Gas Interconnections to the Utility's Pipeline System Rule No. 45 Section K Renewable Gas Quality and Specifications. The terms and conditions contained in Section J apply solely to suppliers of renewable gas and are incremental to Section I's gas quality requirements for their entire gas deliveries if renewable gas is a part of supplier's deliveries. D,N D,N N | | N

K. Termination or Modification L

1. If the customer breaches any terms and conditions of service of the customer's service agreement or the applicable tariff schedules and does not correct the situation within thirty (30) days of notice, the Utility shall have the right to cease service and immediately terminate the customer's applicable service agreement.

2. If the contract is terminated, either party has the right to collect any quantities of gas or money due them for transportation service provided prior to the termination.

L. Regulatory Requirements

1. Any gas transported by the Utility for the customer which was first transported outside the State of California shall have first been authorized under Federal Energy Regulatory Commission (FERC) regulations, as amended. Both parties recognize that such regulations only apply to pipelines subject to FERC jurisdiction, and do not apply to the Utility. The customer shall not take any action which would subject the Utility to the jurisdiction of the FERC, the Economic Regulatory Administration or any succeeding agency. Any such action shall be cause for immediate termination of the service arrangement between the customer and the Utility.

2. Transportation service shall not begin until both parties have received and accepted any and all regulatory authorizations necessary for such service.

M. Warranty and Indemnification

1. The customer warrants to the Utility that the customer has the right to deliver gas hereunder and that such gas is free from all liens and adverse claims of every kind. Customer will indemnify, defend and save the Utility harmless against all loss, damage, injury, liability and expense of any character where such loss, damage, injury, liability or expense arises directly or indirectly out of any demand, claim, action, cause of action or suit brought by any person, association or entity asserting ownership of or any interest in the gas tendered for transportation hereunder, or on account of royalties, payments or other charges applicable before or upon delivery of gas hereunder. L

Rule No. 30 Sheet 23
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

M. Warranty and Indemnification (Continued) N

2. The customer shall indemnify, defend and save harmless the Utility, its officers, agents, and employees from and against any and all loss, costs (including reasonable attorneys' fees), damage, injury, liability, and claims for injury or death of persons (including any employee of the customer or the Utility), or for loss or damage to property (including the property of the customer or the Utility), which occurs or is based upon an act or acts which occur while the gas is deemed to be in the customer's control and possession or which results directly or indirectly from the customer's performance of its obligations arising pursuant to the provisions of its service agreement and the Utility's applicable tariff schedules, or occurs based on the customer-owned gas not meeting the specifications of Sections I or J of this rule. L

N. Temporary Settlement Term

1. The Sections of this Rule italicized and followed by an asterisk (*) are temporary and will end when an adopted decision is issued in SoCalGas' next Triennial Cost Allocation Proceeding. L

L

Rule No. 45 Sheet 1 N

STANDARD RENEWABLE GAS INTERCONNECTION N

Standard Renewable Gas Interconnections to the Utility's Pipeline System N

Table of Contents

N

(Continued)

Rule No. 45 Sheet 2 N
STANDARD RENEWABLE GAS INTERCONNECTION N

(Continued)

Table of Contents (Continued) N

(Continued)

Rule No. 45 Sheet 3 N
STANDARD RENEWABLE GAS INTERCONNECTION N

(Continued)

Table of Contents (Continued) N

(Continued)

Rule No. 45 Sheet 4 N
STANDARD RENEWABLE GAS INTERCONNECTION N

(Continued)

Table of Contents (Continued) N

(Continued)

(Continued)

B. Definitions N

The definitions set forth in this Section B of this Rule shall only apply to this Rule and may not apply to Utility's other tariffs. Certain words beginning with capital letters that are not defined in this Rule may be defined in SoCalGas' Rule 1 and Rule 30 or as approved by Energy Division.

1. Alternative Dispute Resolution (ADR)
   Processes administered by the Administrative Law Judge (ALJ) Division of the Commission to help disputants resolve a conflict without a formal decision by a court or agency.

2. Biogas
   Gas produced from the anaerobic decomposition of organic material.

3. Biomethane
   Biogas that has been conditioned or upgraded to comply with this Rule's gas quality specifications. Biomethane does not include Biogas collected from a hazardous waste facility, as defined in California Health & Safety Code § 25117.

4. Blending
   Utility pipeline mixing with other pipeline gas to dilute conditioned or upgraded Raw Product Gas or Biogas that does not meet all gas specifications at the Interconnection Point to achieve pipeline gas quality specifications as required under the Pipeline Blending Exception Study.

5. British Thermal Unit (Btu)
   The standard unit for measuring a quantity of thermal energy. One Btu equals the amount of thermal energy required to raise the temperature of one pound of water one-degree Fahrenheit and is exactly defined as equal to 1,055.05585262 joule, rounded to 1,055.056 joule. A joule is equal to one watt-second.

6. Btu District
   A physically identifiable area of the gas transmission and/or distribution system in which the heating value of the Gas is measured and is representative of the entire area.

7. California Producer or Production
   An entity which interconnects with the Utility's pipeline system to deliver Gas produced in California.

8. CARB
   California Air Resources Board of the California Environmental Protection Agency. N

(Continued)

(Continued)

B. Definitions (Continued) N

9. CARB/OEHHA Report
The report entitled Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Renewable Natural into the Common Carrier Pipeline, prepared by Staff of the California Air Resources Board and the Office of Health Hazard Assessment. The CARB/OEHHA Report was submitted in Rulemaking (R.)13-02-008 and adopted in Decision (D.) 14-01-034.

10. Commission (CPUC)
The Public Utilities Commission of the State of California, sometimes referred to as the Public Utilities Commission (PUC), CPUC, or Commission.

11. Conditioning or Upgrading
The removal of non-compliant components from Biogas or Raw Product Gas, or the addition of other gases, in order to meet Utility pipeline quality gas specifications. Blending is not considered to be a form of Conditioning or Upgrading.

12. Conditioning or Upgrading Facilities
Interconnector's Facilities used for Conditioning and Upgrading.

13. Constituent of Concern (Constituent)
A chemical or compound that may negatively impact the Merchantability of Renewable Gas.

14. Day(s)
Refers to calendar day(s) unless otherwise stated.

15. Displacement Receipt Point Capacity
Utility pipeline system improvements which increase the takeaway capacity from a Receipt Point but do not increase the overall downstream capacity of the Utility's pipeline system. The addition of Displacement Receipt Point Capacity increases the ability of the Utility to receive gas from a particular Receipt Point or zone in competition with other gas supplies delivered into the Utility's pipeline system.

16. End Use Customer (Customer)
Ultimate consumer of gas using Utility intrastate transportation services on either a bundled, commodity and intrastate transportation basis or an intrastate transportation only basis. N

(Continued)

Rule No. 45 Sheet 7 N
STANDARD RENEWABLE GAS INTERCONNECTION N

(Continued)

B. Definitions (Continued) N

17. Expansion Receipt Point Capacity
Utility pipeline system improvements which increase the takeaway capacity from a Receipt Point and the overall downstream capacity of the Utility's pipeline system.

18. Gas
Any mixture of combustible and non-combustible gases used to produce heat by burning that can be accepted into a Utility pipeline without any compromise to operational safety or integrity. It shall include, but not be limited to, natural gas, renewable gas, biomethane, manufactured gas, or a mixture of any or all of the above. It shall meet the Utility's quality specifications, tariffs, rules, and other applicable regulations.

19. Group 1 Compound
Any Health Protective Constituent with a concentration below the Trigger Level.

20. Group 2 Compound
Any Health Protective Constituent with a concentration at or above the Trigger Level.

21. Hazardous Waste Landfill
For the purposes of this Rule, Hazardous Waste Landfill shall be given the same definition as provided in the California Health and Safety Code, including facilities permitted by the California Department of Toxic Substances Control.

22. Health Protective Constituents
1. Carcinogenic (cancer risk): Any Constituent determined by the State of California to cause cancer, as listed below in Table 1, Maximum Constituent Concentrations.
2. Non-carcinogenic (non-cancer risk or chronic risk): Any Constituent determined by the State of California to cause non-cancer health risk, as listed below in Table 1, Maximum Constituent Concentrations.

23. Heating Value
Total heating value of the gas normally measured on a gross dry higher heating value (HHV) basis (unless otherwise specified), and is defined as the number of British Thermal Units (Btu) evolved by the complete combustion, at constant pressure, of one standard cubic foot of gas with air, the temperature of the gas, air and products of combustion being 60 degrees Fahrenheit and all of the water formed by the combustion reaction being condensed to the liquid state. N

(Continued)

(Continued)

B. Definitions (Continued) N

24. Integrity Protective Constituents
Constituents that may impact the integrity of the Utility's pipeline system as listed in Table 1 Maximum Constituent Concentrations.

25. Interconnect Capacity
The metering, regulation and odorization daily capacity of the Utility Facilities, which is not necessarily the Takeaway Capacity and is not, nor is it intended to be, any commitment by Utility of Takeaway Capacity.

26. Interconnection Point
The point where the Utility Facilities and Interconnector's Facilities physically interconnect for delivery of Gas by Interconnector to, and receipt thereof by, Utility.

27. Interconnector's Facilities
The Gas pipeline facilities constructed and operated by an Interconnector up to the Interconnection Point.

28. Issued for Construction (IFC)
Drawings and documents which are used for construction work and activities.

29. Local Government Entity Renewable Gas Interconnector (Government Entity)
A city or county as defined by Article XI of the California Constitution.

30. Lower Action Level
The concentration or measured value of a Constituent, used to screen Renewable Gas during the initial gas quality review and ongoing periodic testing, requiring a shut-off of Renewable Gas supply if exceeded three times in a 12-month period.

31. Merchantability
The ability to purchase, sell, or market Gas. The Gas shall not contain dust, sand, dirt, gums, oils, microbes, bacteria, pathogens and/or other substances at levels that would be injurious to Utility facilities or which would present a health and/or safety hazard to Utility employees, customers, and/or the public or that would cause Gas to be unmarketable.

32. Million Standard cubic feet per day (MMScfd or MMScf/d)
Volumetric flow rate of Gas measured in millions of standard cubic feet per Day. N

(Continued)

(Continued)

B. Definitions (Continued) N

33. OEHHA
Office of Environmental Health Hazard Assessment of the California Environmental Protection Agency.

34. Raw Product Gas or Feedstock Gas
Gas from biogenic or other renewable sources, such as Biogas, biomass, or power to Gas from renewable electricity, before conditioning or upgrading to comply with this Rule's Gas quality specifications.

35. Receipt Point(s) or Points of Receipt
The place(s) where Interconnector delivers, or has delivered on its behalf, Gas into the Utility's pipeline system.

36. Renewable Gas
Gas from biogenic or other renewable sources, such as Biogas, biomass, or power to Gas from renewable electricity that has been conditioned or upgraded to comply with this Rule's Gas quality specifications, including Biomethane.

37. Renewable Gas Interconnector or Producer (Interconnector)
Party physically interconnecting or interconnected with the Utility and effectuates the delivery of Renewable Gas through new or modified facilities, including any third-party delivering renewable gas into the utility pipeline either directly or through one or more intermediary pipelines, and effectuates the delivery of Renewable Gas through new or modified facilities.

38. Takeaway Capacity
Utility's physical takeaway capability downstream of the outlet of the Utility Facilities at the Interconnection Point. Takeaway Capacity for any particular day may be affected by physical flows from other Receipt Points, physical pipeline and/or storage conditions for that Day, and end-use demand on the Utility's pipeline system, and will be solely determined by the Utility.

39. Thousand Standard cubic feet per day (MScfd or MScf/d)
Volumetric flow of Gas measured in thousands of standard cubic feet per day.

40. Trigger Level
The concentration or measured value of a Constituent requiring additional periodic testing and analysis. N

(Continued)

B. Definitions (Continued) N

41. Upper Action Level
The concentration or measured value of a Constituent requiring an immediate shut-off of Renewable Gas supply.

42. Utility Facilities
Facilities owned and operated by Utility, including but not limited to, pipelines, appurtenant facilities, meters, regulators, quality measurement, other equipment and related system upgrades at and from the Interconnection Point, for receipt into Utility's pipeline system in the State of California pursuant to the Utility's interconnection agreement.

43. Wobbe Index
HHV / (√Relative Densityreal) as defined in Section 2.20 in the 2009 American Gas Association (AGA) Report No. 5 Natural Gas Energy Measurement.

C. Applicability / Open Access

1. Applicability
The Utility shall provide nondiscriminatory open access to its system to any party for the purpose of physically interconnecting with the Utility and effectuating the delivery of Renewable Gas, subject to the terms and conditions set forth in this Rule and the Utility's applicable interconnection, operating, and balancing agreements.

2. End Use Customer Priority
The interconnection and physical flows shall not jeopardize the integrity of, or interfere with, the normal operation of the Utility's pipeline system and provision of service to its End Use Customers.

3. Scheduling and Nominations
The Receipt Point shall be established as a transportation scheduling point, pursuant to the provisions of Utility's transportation of customer owned Gas tariff.

4. Interconnect Capacity and Takeaway Services
The maximum physical capacity of the interconnection will be determined by the sizing of the Receipt Point components, including the metering and odorization capacities, but is not the capacity of the Utility's pipeline system to transport gas away from the Interconnection Point and is not, nor is it intended to be, any commitment by the Utility of Takeaway Capacity. The Utility separately provides takeaway services, including the option to expand system capacity to increase takeaway services, through its otherwise applicable tariffs. N

C. Applicability / Open Access (Continued) N

5. Daily Available Receipt Capacity
The available receipt capacity for any particular day may be affected by physical flows from other Points of Receipt, physical pipeline and storage conditions for that day, and end-use demand on the Utility's pipeline system.

6. Pressure Regulation and Flow
Interconnector's Facilities shall be designed, installed, and operated to protect Utility's pipeline system from exposure to pressures in excess of Utility's then current maximum allowable operating pressure and operating pressures at the Interconnection Point.

Interconnector shall monitor discharge pressure and temperature to limit and shut down, or otherwise control, its compression to ensure that it does not cause any damage to the Utility Facilities.

Interconnector shall ensure that compression does not adversely affect or impair the accuracy of Utility measurement equipment at the Interconnect Point. Interconnector shall eliminate compressor-induced pulsation or vibration in compliance with American Petroleum Industry Standards before Gas is delivered at the Interconnection Point. The Utility shall not be required to accept delivery of Interconnector's Gas if compressor-induced pulsation or vibration exists.

7. Compliance with Utility's Tariffs
Interconnector's Gas supply at the Interconnection Point shall comply with all Utility tariffs, including Gas quality and nomination procedures, except as permitted under the Pipeline Blending Exception Study procedures of this Rule.

8. Authorization Required to Operate
The Interconnector and Utility shall execute interconnection, operating and balancing agreements prior to any performance, including, but not limited to, final interconnection and gas flow.

9. Separate Agreements Required for Other Services
An Interconnector requiring other Gas services from Utility, including, but not limited to, Utility intrastate transportation service, must enter into agreements with Utility for such services in accordance with Utility's CPUC-approved tariffs.

10. Services Under This Rule Limited to Interconnection
Interconnection with Utility's pipeline system under this Rule does not provide Interconnector any rights to use Utility's pipeline system for the transportation or selling of Gas, nor does it limit those rights. N

(Continued)

(Continued)

C. Applicability / Open Access (Continued) N

11. Confidentiality
    Utility and Interconnector may enter into a confidentiality or non-disclosure agreement using Utility's then-existing standard agreement, as needed to protect the confidential, critical infrastructure, and trade secret information of either party. If the Utility provides any confidential, critical infrastructure, and/or trade secret information to the Interconnector, provision of such information shall require the Interconnector to enter into a confidentiality or non-disclosure agreement using Utility's then-existing standard agreement.

12. Compliance with and Modifications to Established Deadlines
    The Utility shall use reasonable efforts to meet all of the timelines provided in this Rule. In the event the Utility is not able to meet a particular timeline, the Utility shall notify the Interconnector as soon as practicable and provide an estimated completion date with an explanation of the reasons why additional time is needed. The Utility and Interconnector shall mutually agree upon a modified timeline. Should mutual agreement not be reached on a modified timeline, the Utility and Interconnector may participate in a dispute resolution process pursuant to Section N of the Rule.

D. Interconnector Request

Interconnector shall complete Utility's interconnect fact sheet and submit a written request for each scope of work: screening, engineering, procurement, and construction as further described herein.

E. Interconnection Screening

1. Applicability
   Any Renewable Gas Interconnector, including an interconnecting pipeline or a supply source, may request one displacement Interconnection Screening for each project, free of charge. Any party may request, on an actual cost basis, an expansion or an additional displacement Interconnection Screening for the project, or a Pipeline Blending Exception Study which entails study of an interconnection to a specific pipeline.

2. Scope of Services
   Utility will analyze the impact on its gas system of receiving Interconnector- specified new supply at specified locations. N

(Continued)

E. Interconnection Screening (Continued) N

2. Scope of Services (Continued)
Utility conducts the following analysis:
a. Preliminary, non-binding initial assessment of the nearest pipeline that has Takeaway Capacity to accommodate Interconnector's maximum injection volume/flow rate, and of a pipeline of lesser capacity closest to the Interconnector's Conditioning Facilities and its Takeaway Capacity.
b. A preliminary pipeline route and length for interconnection to Utility's pipeline system.
c. The then-current maximum allowable operating pressure and, if available, operating pressures of the existing Utility pipeline system receiving Gas from the Receipt Point.

3. Report
The report provided to the Interconnector summarizes the study parameters, assumptions, limitations and results of Utility's analysis. The report shall be provided by the Utility within fifteen (15) business days of its receipt of a written request and complete interconnection fact sheet.

F. Preliminary and Detailed Engineering Studies

1. Preliminary Engineering Study (PES)
a. Applicability; No Self-Performance
Upon completion of the Section E Interconnection Screening, if requested by the Interconnector in writing. Utility will perform the PES in accordance with this Section F-1 and the applicable agreement. Interconnector will not have the option of self-performing the PES.

b. Interconnector Request
Interconnector submits a written request detailing the interconnection expected minimum, average and maximum hourly production volume(s) and proposed site location(s) in addition to the information provided during the Interconnection Screening.

c. Scope of Services
Utility proposes to analyze the impact on its gas system of receiving Interconnector- specified new supply at specified location.

Utility provides:
i. Confirmation that the intended Utility pipeline system has sufficient physical Takeaway Capacity to safely accommodate Interconnector's specified maximum delivery volume. N

(Continued)

Rule No. 45 Sheet 14 N
STANDARD RENEWABLE GAS INTERCONNECTION N

(Continued)

F. Preliminary and Detailed Engineering Studies (Continued) N

1. Preliminary Engineering Study (PES) (Continued)

c. Scope of Services (Continued)
Utility provides:

i. Confirmation that the intended Utility pipeline system has sufficient physical Takeaway Capacity to safely accommodate Interconnector's specified maximum delivery volume.

ii. Recommendation as to the pipeline route using Utility rights of way for interconnection to the gas system.

iii. Confirmation of the then-current maximum allowable operating pressure and, if available, operating pressures of the Utility's gas system.

iv. Potential obstructions in the pipeline route, if applicable, as determined by physical observation by Utility.

v. Cost estimate calculated by the Utility including, but not limited to, land acquisition, site development, right-of-way, metering, gas quality, permitting, regulatory, environmental, unusual construction costs and, if applicable, operating and maintenance costs for any facility improvements. Other service costs associated with construction of the facility that are not part of already offered services could include, but not be limited to, engineering, consulting, contracting, construction costs, environmental studies.

Utility will provide a cost estimate accurate to +100%/- 50% or better based on a site visit and route evaluation for the Interconnector's project in the preliminary engineering estimate.
Because of the exclusions and limitations of this initial review, Utility does not guarantee or recommended use of the PES for any purpose, including any substantive planning or other decisions regarding the cost or viability of its project except to determine whether to proceed with a detailed engineering study.

Any use by the Interconnector is solely at its own risk and should factor in the above risks and limitations. N

(Continued)

F. Preliminary and Detailed Engineering Studies (Continued) N

1. Preliminary Engineering Study (PES) (Continued)

d. Interconnector Pre-payment of Utility Cost Estimates
Interconnector is required to provide funding in advance of a PES being performed for Interconnector's proposed project. Utility personnel will charge their time and any necessary materials to analyze the project on an actual cost basis. Additional funding will be required from Interconnector to continue work if the actual costs exceed the advance.

e. Contracts
The Interconnector and the Utility must execute an agreement prior to initiating any work and Interconnector shall provide payment equal to the estimated cost of the study prior to the Utility proceeding. Within fifteen (15) business days of the Utility's receipt of a request for a PES, the Utility shall provide a draft agreement and estimated cost of the Study to the Interconnector. Payment in full of the estimated cost is required upon execution of an agreement to proceed with the analysis. The Interconnector will be responsible for the actual costs of the services; to this end, an invoice or a refund will be issued to the Interconnector at the completion or earlier termination of the PES for any difference between the actual costs and this advance.

f. PES Report
The Utility shall complete the PES within ninety (90) business days of Interconnector's payment of the estimated study cost. The report summarizes the study parameters, assumptions, limitations and results of Utility's analyses, identifies any facility improvements, and estimates the cost of construction of those improvements. The use and distribution of the PES shall be governed by the confidentiality agreement signed by the Utility and the Interconnector.

2. Detailed Engineering Study (DES)

a. Applicability; Option to Self-Perform
Upon completion of the PES or in combination with a PES, if requested by the Interconnector in writing. Interconnector will have the option of self-performing the DES, in which case:

i. the Interconnector shall be responsible for all tasks in the DES, including but not limited to, permits, land rights, and environmental studies; N

F. Preliminary and Detailed Engineering Studies (Continued) N

2. Detailed Engineering Study (DES) (Continued)

a. (Continued)

ii. The Interconnector must pay the Utility for the Utility's review and approval costs of each step of the DES process, and for each stage of construction;

iii. Within fifteen (15) business days of notice that the Interconnector will prepare a DES, the Utility shall provide relevant guidance regarding the required content of the DES; and

iv. The Interconnector shall pay the Utility's actual costs for reviewing and assisting with preparation of the DES, within forty (40) business days of receiving invoices from the Utility.

If Interconnector elects to have Utility prepare the DES, the remainder of this Section F-2 shall apply.

b. Interconnector Request
Interconnector submits a written request detailing the interconnection expected production volume(s) and proposed site location(s).

c. Scope of Services (Work)
Utility will design and engineer interconnection facilities or provide specifications, inspection and oversight of the Interconnector design and engineering of the interconnection facilities including a Receipt Point station and lateral pipeline, if applicable. Cost estimates may be generated at 30%, for long-lead material items, 60% level and at Issued for Construction level, of facility design based on the Interconnector's estimated completion date accurate to +50% / -30%.

i. Confirm pipeline route using Utility rights-of-way for interconnection to the Gas system.

ii. Confirm obstructions in the pipeline route, if applicable, as determined by physical observation by Utility. N

(Continued)

F. Preliminary and Detailed Engineering Studies (Continued) N

2. Detailed Engineering Study (DES) (Continued)

c. (Continued)

iii. Cost estimate calculated by the Utility including, but not limited to, land acquisition, site development, right-of-way, metering, gas quality, permitting, regulatory, environmental, unusual construction costs and, if applicable, operating and maintenance costs for any facility improvements. Other service costs associated with construction of the facility that are not part of already offered services could include, but not be limited to, engineering, consulting, contracting, construction costs, environmental studies.

d. Interconnector Pre-payment of Utility Cost Estimate
Engineering advances will be collected to fund the DES through commissioning and final drawings. Interconnector is responsible for making all payments in advance of Utility's performance of the interconnection work scope and for the purchase of long lead equipment. All final payments will be determined on the basis of the actual DES project costs incurred by Utility.

e. Contracts
The Interconnector and the Utility must execute an agreement prior to an analysis being performed and payment shall have been provided prior to Utility proceeding with the analysis. Within twenty (20) business days of a request for the Utility to prepare a DES, the Utility shall meet with the Interconnector to discuss project specific design parameters and the Utility shall provide the Interconnector an estimate of the cost to prepare the DES and a proposed agreement. The Interconnector will be responsible for the actual costs of the services; to this end, a refund or an invoice will be issued to the Interconnector at the completion of the DES to true-up actual costs to the estimated costs. Within fifteen (15) business days of notice that the Interconnector will prepare a DES, the Utility shall provide relevant guidance regarding the required content of the DES. The Interconnector shall pay the Utility's actual costs for reviewing and assisting with preparation of the DES, within forty (40) business days of receiving invoices from the Utility.

f. DES Report
The Utility shall complete the DES within one hundred eighty (180) business days of Interconnector's payment of the estimated study cost. The report summarizes the study parameters, assumptions, limitations and results of Utility's analyses, identifies any facility improvements, and estimates the cost of construction of those improvements. The use and distribution of the DES shall be governed by the confidentiality agreement signed by the Utility and Interconnector. N

(Continued)

G. Procurement and Construction and Installation Options N

1. Procurement of Equipment and Materials; Construction and Installation

a. Procurement and Construction and Installation Options
Interconnector may elect for Utility or Interconnector to construct and install new Receipt Point facilities. The party performing the construction and installation work will also be exclusively responsible for procuring the equipment and materials for such work. In either case, Interconnector will be subject to the procurement, construction, and installation terms and conditions provided by the Utility, including those set forth in the interconnection agreement.

b. Commissioning Gas Quality Verification
Prior to commencing Utility operations, sampling of Interconnector's Renewable Gas shall be performed according to the procedures in Section K.5 Renewable Gas Quality and Specifications Testing, as revised from time to time.
Utility may, at Interconnector's expense, perform gas quality and equipment startup testing to verify compliance with this Rule's gas quality specifications and proper operation of gas quality monitoring equipment and enforcement system. Commissioning Gas Quality Verification, as described in this section, also applies to any new gas source supplying Renewable Gas upstream of an existing gas interconnection point.

c. Receipt Point Facilities Ownership
Receipt Point facilities provided by Utility under this Rule or transferred to Utility as part of any Interconnector design-build shall, at all times, be and remain the property of Utility.

2. Alternative Interconnection of a Renewable Gas Production Facility

The parties may consider alternatives to Receipt Point and Utility Facilities to enable interconnection of a Renewable Gas production facility to the Utility pipeline system such as, but not limited to, the utilization of mobile and temporary resources for the delivery of Renewable Gas to the Utility pipeline system. At the Utility's sole discretion, the parties may negotiate interconnection alternatives. N

Rule No. 45 Sheet 19 N
STANDARD RENEWABLE GAS INTERCONNECTION N

(Continued)

H. Interconnection Request Withdrawal N

1. Interconnector may withdraw its Interconnection Request at any time by written notice of such withdrawal to Utility.

2. Withdrawal shall result in the removal of the Interconnection Request from the interconnection process and Utility shall return any unspent funds less any costs to discontinue the work and return the site(s) to pre-existing conditions received from the Interconnector, if applicable.

3. In the event of such withdrawal, Utility shall provide, at Interconnector's request, any completed engineering study conducted up to the date of withdrawal of the Interconnection Request.

I. Costs

1. Interconnector Cost Responsibility
The Interconnector shall pay all costs necessary to effectuate and maintain deliveries at and from the Interconnection Point, including but not limited to computer programming changes to the Utility's pipeline system, engineering, equipment and construction (valves, separators, meters, quality measurement, odorant, and other equipment), land rights and permits necessary to regulate and deliver gas to and from the Interconnection Point, and repairs, upgrades, modifications, or replacements of the Utility Facilities.

2. Expansion of Receipt Point and/or Takeaway Capacity
The Utility will expand specific Receipt Point capacity and/or Takeaway Capacity at the request and expense of the Interconnector. The Interconnector and the Utility must execute the applicable Utility agreement prior to any work commencing.

3. Operation and Maintenance
Utility shall recover its operation and maintenance costs, as determined from time to time by the Utility, associated with the operation and maintenance of the metering equipment and other related facilities at and from the Interconnection Point that are owned and operated by the Utility and that are necessary to accept Renewable Gas from Interconnector and redeliver it to End Use Customers in accordance with good industry practice, Utility's normal procedures and governmental regulations pursuant to the Utility interconnection agreement. N

(Continued)

(Continued)

I. Costs (Continued) N

4. Repair, Upgrade, Modification or Replacement of Utility's Facilities

a. Utility
Utility shall provide notice, except under emergency conditions, to Interconnector if Utility determines, at Utility's sole discretion, that the Utility's Facilities, require repair, upgrade, modification or replacement to operate in compliance with applicable laws, regulations or Public Utilities Commission orders.

Utility's notice shall describe and include Utility's estimate to perform the necessary repairs, upgrades, modifications or replacements, all of which will be at Interconnector's expense as set forth in this Rule's Section I.1, and, if applicable, be prorated for each Interconnector based on each Interconnector's share of the total Interconnect Capacity.

b. Interconnector
Interconnector shall notify Utility within thirty (30) days of receipt of Utility's notice that the Interconnector requests that Utility make the necessary repairs, upgrades, modifications or replacements, which will be at Interconnector's expense.

The Interconnector shall have the right to review and to propose reasonable changes to any Utility proposal or request to repair, upgrade, modify or replace existing equipment so long as the Interconnector's proposed changes meet industry and Utility's standards and applicable codes and neither delay implementation nor jeopardize timely safety and code compliance. Utility is, however, under no obligation, expressed or implied, to accept such proposed changes.

Interconnector shall pay Utility within sixty (60) days of the date of the Interconnector's receipt of Utility's estimate for the necessary repairs, upgrades, modifications or replacements. At Utility's sole discretion, the Parties may agree on a mutually agreeable payment schedule subject to Utility's credit requirements.

If any Interconnector fails to request in writing that Utility make the necessary repairs, upgrades, modifications or replacements within thirty (30) days of receipt of Utility's notice and fails to pay Utility's estimated costs, within sixty (60) days of receipt of Utility's estimate, then Utility shall have the right to refuse to accept that Interconnector's Gas, and may proceed to reallocate the Interconnect Capacity and costs to the remaining Interconnectors or abandon, retire, or sell the Receipt Point facilities, at its sole discretion.

Any Utility abandonment shall be at Interconnector's sole expense. N

(Continued)

I. Costs (Continued)

4. Repair, Upgrade, Modification or Replacement of Utility's Facilities (Continued)

c. Reconciliation of Actual to Estimated Costs

If, at any time and upon completion of the work, the Utility costs exceed or are expected to exceed Utility estimated costs or Interconnector's payments, Utility will invoice the Interconnector for the difference between the estimate and the Utility costs. Interconnector shall pay the invoice for the remaining amount to Utility within thirty (30) days of receipt. At Utility's sole discretion, the Parties can agree on a mutually agreeable payment schedule subject to Utility credit requirements. Upon completion of the work, if the Utility costs are less than Utility's estimate, Utility will refund the difference between the paid estimate and the Utility costs within thirty (30) days of the invoice.

5. Incentive Programs

a. Background

Pursuant to D.15-06-029, as modified by D.16-12-043 and D.19-12-009 and expanded by N
D.20-12-031, the Utility shall provide a monetary incentive to eligible Biomethane N
Interconnections built before December 31, 2026. The monetary incentive program shall be in effect until the end of December 31, 2026, or until the program has exhausted its $40 million funding, including the California Council on Science and Technology study costs. D

b. Monetary Incentive

The monetary incentive is for up to 50% of the eligible interconnection costs incurred by a Biomethane Interconnector, up to $3 million per interconnection for a non-dairy cluster Biomethane Interconnector and up to $5 million per interconnection for a dairy cluster Biomethane Interconnector. A dairy cluster Biomethane interconnection project, as defined by Public Utilities Code Section 399.19(b), is a Biomethane project of three or more dairies in close proximity to one another employing multiple facilities for the capture of Biogas that is transported to a centralized processing facility and ultimately injected into the Utility pipeline through a single interconnection.

The funds authorized pursuant to D.20-12-031 may be expended once the funds approved pursuant to D.15-06-029 have been allocated to projects with an incentive reservation. N

Should a project in a gas utility's service territory not be operational within the three-year period established in D.19-12-009, then the funds reserved for that project shall instead be made available to the next candidate in that service territory. N

I. Costs (Continued)

5. Incentive Programs (Continued)

b. Monetary Incentive (Continued) N
If a balance remains in the funds approved pursuant to D.15-06-029 and there are no candidates remaining in that service territory on the waitlist, then the funds shall be made available to the next project on the waitlist, regardless of service territory.

If there are funds remaining at the time of program termination, Biomethane Interconnectors that have started to deliver qualifying 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. N

c. Eligible Interconnection Costs
The monetary incentive is limited to eligible interconnection costs, which include:

i. Engineering costs (Interconnect Screening, Preliminary Engineering Study, and Detailed Engineering Study costs).

ii. Costs associated with facilities downstream of the Biomethane Interconnector's processing plants used for delivering Biomethane into the Utility or third-party pipeline system.

iii. Total installed costs of receipt point facilities. These facilities include, but are not limited to: meters, regulators, appurtenant facilities, quality measurement, odorization facilities, and auxiliary facilities.

iv. Facility enhancement costs. These enhancements include but are not limited to: enhancements to gas pipelines and other related system upgrades that are required to enable continued safe and reliable operation of Utility's system due to the addition of each Biomethane Interconnection.

v. For dairy cluster Biomethane Interconnection, costs incurred for Biogas gathering lines to help reduce emissions of short-lived climate pollutants pursuant to Section 39730 of the Health and Safety Code shall be considered eligible costs.

Other costs associated with processing and blending upstream of Interconnection Point, including facilities serving natural gas to Biomethane Interconnector's facilities, are ineligible costs.

L

I. Costs (Continued)

5. Incentive Programs (Continued)

d. Eligibility of Interconnector for Monetary Incentive
To be eligible for the monetary incentive program, a Biomethane Interconnector must: L

i. Comply with Utility's rule regarding transportation of customer-owned gas SoCalGas Rule 30, Transportation of Customer Owned Gas, and this Rule.

ii. Comply with the standard and protocols adopted in D.14-01-034 as modified by D.16-11-008. L

iii. Successfully interconnect to the Utility or third-party California pipeline system and meet the operational requirement as described in D.15-06-029 as modified by D.16-12-043. This operational requirement entails that the Biomethane Interconnector produce Biomethane flow for a minimum of 30 days out of a 40- day testing period, within the minimum and maximum measurement range of the meter, as specified by Utility's measurement standards and based on the meter type specified by the Utility.

a) Biomethane Interconnectors must declare in a written notice to the Utility at least two business days in advance, the specific start and end date of this 40- day testing period.

b) The 30 out of 40-day requirement is extended 1 day for each day that the Biomethane Interconnector is unable to produce flow because of an interruption of delivery as set forth in Utility's rule regarding interruption of delivery.

c) Biomethane Interconnectors may elect to restart the 40-day testing period by providing a new written notice declaring the new start and end dates at least two business days in advance of when the new 40-day testing period is to begin.

iv. Provide cost information to Utility for eligible costs in a timely manner, as specified by Utility.

(Continued)

I. Costs (Continued) N

5. Incentive Programs (Continued)

e. Payment of Monetary Incentive
Within 60 days following successful compliance with the 30 out of 40-day biomethane delivery requirement, the Utility will pay the Biomethane Interconnector the amount up to 50% of the eligible reconciled and undisputed portions of the interconnection costs, not to exceed $3 million per interconnection for a non-dairy cluster Biomethane Interconnector, or $5 million per interconnection for a dairy cluster Biomethane Interconnector. Payment will be provided to the Biomethane Interconnector if all costs have been paid in full; if there are remaining costs it shall be treated as a credit. In the event that all interconnection costs have not been reconciled by the Utility and the Biomethane Interconnector within 60 days following the successful compliance with the 30 out of 40-day Biomethane delivery requirement, the Utility shall resume paying the Biomethane Interconnector upon cost reconciliation. If additional eligible cost information becomes available within 12 months following the initial payment, the Utility shall pay to the Biomethane Interconnector up to 50% of the remaining eligible interconnection costs, not to exceed $3 million per interconnection for a non-dairy cluster Biomethane Interconnector, or $5 million per interconnection for a dairy cluster Biomethane Interconnector, including all previous payments. The Utility will provide notification to the CPUC Director of the Energy Division and the Biomethane Interconnector of the initial payment as well as any other potentially eligible future payments.

f. Monetary Incentive Reservation Application Process

i. Interconnector must submit the standard Incentive Reservation Application as required by D.19-12-009.

ii. Upon receipt of a standard Incentive Reservation Application, the Utility will note the date and time of the receipt of the application.

iii. Utilities must verify that the project meets the Incentive Reservation qualifications. The required qualifications are:

a) A completed application which includes Contact Information, Interconnecting Facility Information, and a Proposed Schedule.

b) Documentation of a fully executed and funded agreement to conduct a detailed engineering study. N

(Continued)

(Continued)

I. Costs (Continued) N

5. Incentive Programs (Continued)

f. Monetary Incentive Reservation Application Process (Continued)

iii. (Continued)

c) Utilities will deliver verified Incentive Reservation Applications to the Commission's Energy Division within 5 business days of its receipt.

d) Utilities will provide a quarterly report to the Energy Division within 5 business days of the end of each quarter for all applicants with a reservation on the waiting list reporting the status of the interconnection project.

e) Applicant's project must be operating within three years of the date of the Energy's Division's award of an Incentive Reservation to qualify to receive the incentive.

J. Local Government Entity Renewable Gas Interconnectors

Local Government Entity Renewable Gas Interconnectors may be evaluated by the Utility on a case-by-case basis for the granting of contractual provisions that recognize commercial considerations unique to local government entities including, but not limited to:

1. Transference of title to land owned by the government entity to the Utility or, alternatively, provision of easements satisfactory to the Utility, for the purpose of establishing the Utility's Facilities;

2. Local Government Entity Renewable Gas Interconnectors that generally can meet contractual obligations are not required to post performance assurance; and

3. Allowance of additional flexibility for a Local Government Entity Renewable Gas Interconnector to make payments based on the meeting cycle of the governing body. N

(Continued)

K. Renewable Gas Quality and Specifications N

1. Base Utility Gas Specifications
Renewable Gas must meet the gas quality specifications identified in SoCalGas' Rule 30 I. and this Rule 45, as adopted and periodically updated by the Commission.

2. Renewable Gas Constituent Concentrations
In addition to Section K.1. requirements, the following requirements are also applicable to Renewable Gas injected into the Utility's gas system. The Biomethane rules in this section are intended to implement D.14-01-034 and D.19-05-018, including rules regarding Constituent concentration standards, monitoring and testing requirements, and reporting and record keeping requirements.

a. Renewable Gas must conform to the specifications listed in Table 1 and Table 2.

Table 1
Maximum Constituent Concentrations

Renewable Gas Injection Constituents				**Testing for Gas Source**		
	Trigger Level	**Lower Action Level**	**Upper Action Level**	**Non-Hazardous Landfill**	**Dairies**	**Other**[4]
Base Gas Quality Specifications [1]				X	X	X
Health Protective Constituents (HPC) – Carcinogenic [2]						
Arsenic	0.019 mg/m^3 0.006 ppmv	0.19 mg/m^3 0.06 ppmv	0.48 mg/m^3 0.15 ppmv	X		
p-Dichlorobenzene	5.7 mg/m^3 0.95 ppmv	57 mg/m^3 9.5 ppmv	140 mg/m^3 24 ppmv	X		X

N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

2. Renewable Gas Constituent Concentrations (Continued)

a. (Continued)

Table 1 (Continued)
Maximum Constituent Concentrations

Ethylbenzene	26 mg/m^3 6.0 ppmv	260 mg/m^3 60 ppmv	650 mg/m^3 150 ppmv	X	X	X
n-Nitroso-di-n-propylamine	0.033 mg/m^3 0.006 ppmv	0.33 mg/m^3 0.06 ppmv	0.81 mg/m^3 0.15 ppmv	X	X	
Vinyl Chloride	0.84 mg/m^3 0.33 ppmv	8.4 mg/m^3 3.3 ppmv	21 mg/m^3 8.3 ppmv	X		X
Health Protective Constituents (HPC) - Non-Carcinogenic [2]						
Antimony	0.60 mg/m^3 0.12 ppmv	6.0 mg/m^3 1.2 ppmv	30 mg/m^3 6.1 ppmv	X		
Copper	0.060 mg/m^3 0.02 ppmv	0.60 mg/m^3 0.23 ppmv	3.0 mg/m^3 1.2 ppmv	X		
Hydrogen Sulfide [6]	30 mg/m^3 22 ppmv	300 mg/m^3 216 ppmv	1500 mg/m^3 1080 ppmv	X	X	X
Lead	0.075 mg/m^3 0.009 ppmv	0.75 mg/m^3 0.09 ppmv	3.8 mg/m^3 0.44 ppmv	X		
Mercaptans (Alkyl Thiols) [6]	12 ppmv	120 ppmv	610 ppmv	X	X	X
Methacrolein	1.1 mg/m^3 0.37 ppmv	11 mg/m^3 3.7 ppmv	53 mg/m^3 18 ppmv	X		
Toluene	904 mg/m^3 240 ppmv	9000 mg/m^3 2400 ppmv	45000 mg/m^3 12000 ppmv	X	X	X
Integrity Protective Constituents (IPC) [3]						
Ammonia	0.001%	TBD [5]	TBD [5]	X	X	X

N

(Continued)

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

2. a. (Continued)

Table 1 (Continued)
Maximum Constituent Concentrations

Biologicals	4×10^4 / Scf (qPCR per APB, SRB, IOB[7] group) and commercially free of bacteria of > 0.2 microns	TBD [5]	TBD [5]	X	X	X
Hydrogen	0.10%	TBD [5]	TBD [5]	X	X	X
Mercury	0.08 mg/m^3	TBD [5]	TBD [5]	X	X	X
Siloxanes[8]	0.01 mg Si/m^3	0.1 mg Si/m3	TBD [5]	X	X	X

Notes:
1. Base Utility Gas Specifications are identified in K1.
2. Health Protective Constituents (HPC) are shown in Table V-3 of the CARB/OEHHA Report.
3. Integrity Protective Constituents are shown in Section 4.4.3.3 of D.14-01-034 and identified as pipeline integrity protective constituents.
4. Other organic sources, includes all Biogas sources other than landfill and dairy manure, including but not limited to, a sewage treatment plant or wastewater plant ("Publicly Owned Treatment Works" or “POTW”).
5. The Lower and Upper Action Levels will be established in the next update proceeding.
6. Testing requirement will be the stricter of the stated Renewable Gas values or other tariff requirements.
7. Acid-producing Bacteria (APB), Sulfate-reducing Bacteria (SRB), and Iron-oxidizing Bacteria (IOB).
8. The Interconnector that meets this Rule’s Section K.4.b certification requirements shall have reduced siloxanes testing requirements. Utility, at its discretion and at its own cost, may still test pursuant to Utility’s applicable tariff rules. If the Utility test results show the siloxane levels exceed the Lower Action Level, the full siloxane testing requirements will apply as described in this Rule. N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

2. a. (Continued)

Table 2
Collective Risk from Carcinogenic and non-Carcinogenic Constituents

Risk Management Levels	Risk from Carcinogenic Constituents (chances in a million)	Hazard Index from Non-Carcinogenic Constituents	Action
Trigger Level [1]	≥ 1.0	≥ 0.1	Periodic Testing Required
Lower Action Level [2]	≥ 10.0	≥ 1.0	Supply shut-in after three exceedances in 12 months in which deliveries occur
Upper Action Level [3]	≥ 25.0	≥ 5.0	Immediate supply shut-in

Notes:
1. Applies to individual Constituent concentrations.
2. Applies to the sum of all Constituent concentrations over the Trigger Level.
3. Applies to individual Constituent concentrations or to the sum of all Constituent concentrations over the Trigger Level.

3. RESERVED

4. Interconnector Renewable Gas Source Certification

a. Non-Hazardous Waste Facility
Renewable Gas sourced from Hazardous Waste Landfills will not be knowingly purchased, accepted into or transported on the pipeline system.

i. Interconnector must certify and provide documentation or other suitable proof that: the Renewable Gas source feedstock was not derived or collected from a Hazardous Waste Facility, as that term is defined in Section 25117.1 of the California Health and Safety Code, as may be amended from time to time, and Interconnector is in compliance with the following Health and Safety Code Sections 25421(g)(1) and (2), as they may be amended from time to time.

b. Siloxanes
To qualify for reduced siloxanes testing, Interconnector must execute Utility's certification attesting that: N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

4. Interconnector Renewable Gas Source Certification (Continued)

b. Siloxanes (Continued)

i. Interconnector's Biogas is sourced only from dairy, animal manure, agricultural waste, forest residues, and/or commercial food processing waste;

ii. Products containing siloxanes are not used at Interconnector's Facilities in any way that allow siloxanes to enter the Biogas and/or Biomethane and

iii. Interconnector shall notify Utility within 30 days of discovery, in accordance with the notice provision of the associated interconnection agreement, that the certifications set forth in the above paragraphs are no longer true.

5. Testing

a. Source Feedstock Based Testing

Testing shall be determined according to the source feedstock. Testing for the Health Protective Constituents shall be by the recommended methods specified in Table V-4 of CARB/OEHHA Report submitted in R.13-02-008 as approved by D.14-01-034 or an equivalent national standard test. Testing for Integrity Protective Constituents shall be by national standard test methods or equivalent. Feedstock Based Testing, as described in this section, also applies to any new gas source supplying Renewable Gas upstream of an existing gas interconnection point.

b. Testing Responsibility

i. Interconnector Pre-Injection and Restart Procedure Testing

Pre-injection and Restart Procedure testing for gas quality will be performed by the Interconnector using independent certified third-party laboratories. The Utility shall be notified of the sampling in advance and have the option to observe the samples being taken.

ii. Utility Periodic Testing

The Utility will collect the samples and send the samples to an independent certified laboratory for Constituent analyses. The results will be shared with the Interconnector within two weeks of the Utility receiving the data. If it is agreed to by both parties, the Interconnector can be the periodic testing entity at the interconnection. N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

5. Testing (Continued)

c. Cost Responsibility
Interconnector is responsible for Pre-Injection, Periodic Testing and Restart testing costs. If requested, any retesting for validation of results shall be done at the cost of the entity requesting the retest.

d. Utility Discretionary Testing
This Rule does not prohibit the Utility from engaging in discretionary gas or facility testing on its system at Utility's expense.

e. Pre-Injection Testing Procedure
Interconnector will conduct two successful tests for all Constituents over a two to four-week period, preferably, at least two weeks apart.

i. Health Protective Constituents
If during the pre-injection testing, any Health Protective Constituents are found at or above the Trigger Level, the collective potential cancer or non-cancer risk must be calculated. The collective potential cancer or non-cancer risk is calculated by summing the individual risk for each Health Protective Group 2 Compound.

If the collective potential cancer risk or non-cancer risk is at or above the Lower Action Level (the cancer risk Lower Action Level is ≥10 in a million and the non- cancer risk Lower Action Level is a Hazard Index of ≥1), the Renewable Gas cannot be accepted or transported by the Utility's pipeline system.

The Interconnector shall make necessary modifications to lower the collective potential cancer or non-cancer risk below the Lower Action Level and restart pre- injection testing.

If all the Health Protective Constituents are below the Trigger Level or the collective potential cancer risk and non-cancer risk from the Group 2 Compounds are below the Lower Action Level in both pre-injection tests, the Renewable Gas may be injected into the pipeline system subject to all other requirements set forth in this Rule. N

K. Renewable Gas Quality and Specifications (Continued) N

5. Testing (Continued)

e. Pre-Injection Testing Procedure (Continued)

ii. Integrity Protective Constituents

If any Integrity Protective Constituents are above the Lower Action Level, the Renewable Gas may not be injected into the Utility's system. The Interconnector shall make necessary modifications to lower the levels of the Integrity Protective Constituents to levels below the Lower Action Level equivalent and restart pre-injection testing.

If Integrity Protective Constituents are at or below the Lower Action Level, the Renewable Gas may be injected into the Utility's system subject to all other requirements set forth in this Rule.

a) Reduced Siloxanes Testing

Pursuant to Section K.4.b Renewable Gas certified for reduced siloxanes testing will be as follows:

(i) If the pre-injection testing siloxanes levels are at or below the Trigger Level, then no periodic testing for siloxanes is required.

(ii) If the pre-injection testing siloxanes level exceeds the Trigger Level, then quarterly testing for siloxanes is required for one year, and if none of those samples are above the Lower Action Level, then no periodic testing for siloxanes is required.

(iii) If the siloxanes are above the Lower Action Level, then the Renewable Gas certification for reduced testing is no longer applicable and the Interconnector will be required to comply with the periodic testing requirements for siloxanes.

(iv) Utility, at its discretion and at its own cost, may still test pursuant to Utility's applicable tariff rules. If the Utility test results show the siloxanes levels exceed the Lower Action Level, this Rule's full siloxanes testing requirements will apply. N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

5. Testing (Continued)

f. Periodic Testing

i. Group 1 Compounds

a) Group 1 Compounds will be tested once every 12-month period in which injection occurs.

b) Any Group 1 Compounds with a concentration below the Trigger Level for two consecutive annual tests will be tested once every two-year period in which injection occurs.

c) A Group 1 Compound will become a Group 2 Compound if testing indicates a concentration at or above the Trigger Level and will be tested quarterly.

ii. Group 2 Compounds

a) Testing for Group 2 Compounds will be quarterly (at least once every three- month period in which injection occurs).

b) Any Group 2 Compound with a concentration below the Trigger Level in four consecutive quarterly tests will become a Group 1 Compound and will be tested once every 12-month period in which injection occurs.

c) If any constituent is above the Upper Action Level, the Renewable Gas shall be shut-in until the concentration level is below the Lower Action Level, after which it will be subject to the Section K.5.g. Restart Procedure. N

(Continued)

Rule No. 45 Sheet 34 N
STANDARD RENEWABLE GAS INTERCONNECTION N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

5. Testing (Continued)

f. Periodic Testing (Continued)

iii. Collective risk from Carcinogenic and Non-carcinogenic Health Protective Constituents

a) Cancer Risk
The collective potential cancer risk for Group 2 Compounds is determined by summing the individual potential cancer risk for each carcinogenic Constituent of Concern. Specifically, the cancer risk is calculated using the ratio of the concentration of the Constituent in the Renewable Gas to the health protective ("trigger") concentration value corresponding to one in a million cancer risk for that specific Constituent and then summing the risk for all the Group 2 Compounds (for reference, see CARB/OEHHA Report submitted in R.13-02-008, p. 67).

b) Non-Cancer Risk
The collective non-cancer risk is calculated using the ratio of the concentration of the constituent in Renewable Gas to the health protective concentration value corresponding to a hazard quotient of 0.1 for that specific non-carcinogenic constituent, then multiplying the ratio by 0.1, and then summing the non-cancer chronic risk for these Group 2 compounds (for reference, see CARB/OEHHA Report submitted in R.13-02-008, p. 67).

c) If the result is at or above the Lower Action Level on three occurrences in a 12-month period, the Renewable Gas shall be immediately shut-in until the levels are below the Lower Action Level, after which it will be subject to the Restart Procedures.

d) If quarterly testing over four consecutive tests demonstrates that the collective risk from Carcinogenic and Non-carcinogenic Constituents is below the Lower Action Level, then the testing period will change to once every 12- month period during which injection occurs for each Constituent in the group. N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

5. Testing (Continued)

f. iii. (Continued)

e) If annual testing demonstrates that collective risk from Carcinogenic and Non-carcinogenic Group 2 Compounds is at or above the Lower Action Level, then testing will revert to quarterly.

f) If the collective risk from Carcinogenic or Non-carcinogenic Constituents, is at or above the Upper Action Level, the Renewable Gas shall be shut-in until the concentration is below the Lower Action Level, after which it will be subject to the Restart Procedures.

g) If Interconnector's Renewable Gas is refused in accordance with this Rule, testing for all Group 1 and Group 2 Compounds will then be performed according to the Restart Procedure.

iv. Integrity Protective Constituents

a) Constituents shall be tested once every 12-month period in which injection occurs.

b) Any Constituent with a concentration at or below the Trigger Level during two (2) consecutive annual periodic tests shall be tested once every two-year period in which injection occurs.

c) If periodic testing demonstrates that any Constituent is above the Trigger Level, then it will be tested quarterly.

d) If the Constituent is above the Trigger Level, then it will be tested quarterly until there are four (4) consecutive quarterly tests at or below the Trigger Level, then it will be reduced to once every 12-month period in which deliveries occur.

e) When any Constituent is above the Lower Action Level three times in a 12-month period, the Renewable Gas shall be immediately shut-in and subject to Restart Procedures set forth in Section K.5.g. of this Rule. N

K. Renewable Gas Quality and Specifications (Continued) N

5. Testing (Continued)

g. Restart Procedure

i. Interconnector will repeat the Pre-Injection Testing Procedure until one successful test of all Constituents is completed, when any of the following occurs:

a) There is a change in the Gas source at the facility or a change of the Gas processing equipment design (other than for functional equivalence) that the Commission determines will potentially increase the level of any Constituent over the previously measured baseline levels.

b) A shut-in of the Renewable Gas into the pipeline because there are three exceedances of the Lower Action Level in a 12-month period of the same Constituent.

c) A shut-in of the Renewable Gas into the pipeline because a Constituent concentration or the collective cancer or non-cancer risk is above the Upper Action Level.

ii. After re-starting Renewable Gas deliveries, Periodic Testing will resume based on the results of the successful test.

h. Reporting and Record Keeping Requirements
Reporting and Record Keeping will be in compliance with D.14-01-034 and the CARB/OEHHA Report and includes the following:

i. Pre-injection testing results shall be provided by Interconnector to the Utility within five days of receiving the data.

ii. Startup test results shall be provided to Commission within 30 days of receiving the test data by the testing entity (Utility or Interconnector).

iii. Maintain records of all test results for 3 years from the date when the tests were conducted by the testing entity (Utility or Interconnector).

iv. Annual report to Commission: all test data, production rate, monitoring parameters, and shutoff events. N

(Continued)

K. Renewable Gas Quality and Specifications (Continued) N

5. Testing (Continued)

h. Reporting and Record Keeping Requirements (Continued)

v. If the Utility is the testing entity, test results shall be provided by Utility to the Interconnector within two weeks of receiving the data. Test data that results in shut off shall be provided within 24 hours of receiving the data.

vi. If the Interconnector is the testing entity, the Interconnector shall provide the above information to the Utility within two weeks of receiving the data.

L. Pipeline Blending Exception Study (Blending Study)

1. Intent
In an effort to encourage interconnections of Renewable Gas to Utility pipelines as ordered in D.19-05-018, the Utility will review and consider each blending request thoroughly and make a determination regarding each request. Blending exception requests will be accepted if the Renewable Gas is interchangeable with historical or contractual Gas supplies after blending and will not cause increased risk or safety concerns to the Utility's employees, downstream customers or pipeline. The Interconnector requesting the Blending Study will be responsible for the cost for the Utility to conduct the Blending Study and provide a determination.

2. Interconnector Blending Study Request
Interconnector may request a Blending Study to determine the Utility's downstream blending capability from an Interconnection Point, or proposed Interconnection Point, and the associated Utility monitoring and equipment enhancement costs, if any to be borne by Interconnector.
Interconnector may request an exception to the Gas quality and Heating Value standards established in this rule for a Receipt Point to allow blending in the pipeline of conditioned or upgraded Raw Product Gas or Biogas that does not meet all gas specifications at the Interconnection Point to achieve pipeline gas quality specifications.
Interconnector may initiate a Blending Study request as part of the Interconnection Screening or a subsequent Preliminary or Detailed Engineering Study.
The Blending Study will evaluate feasibility of blending to determine interchangeability with historical or contractual Gas supplies and the increased risk or safety concerns to the Utility's employees, downstream customers or pipeline.
The Utility will evaluate whether it is safe to authorize blending following receipt of the request that shall include the following: N

(Continued)

L. Pipeline Blending Exception Study (Blending Study) (Continued) N

2. Interconnector Blending Study Request (Continued)

   a. Desired interconnect location(s) on the Utility's system

   b. Maximum and minimum flow rates, including seasonal variations, if appropriate

   c. Maximum concentrations of all Constituents listed within this Rule

   d. Maximum and minimum Heating Value and Wobbe Index

   e. Ability of Interconnector to accept limits on flow rates

   f. Reason for request

   g. Information collected from Interconnection Request

3. Utility Evaluation
   If blending is requested, the Utility will evaluate requests for safely blending into the pipeline to determine whether injection of any new or modified supply source can be safely injected into the Utility's pipeline system. At a minimum, the Utility will consider the following factors when determining whether an exception can be allowed:

   a. Flow rates and directional consistency of receiving pipeline(s), including daily and seasonal variations.

   b. Historical Gas composition and contractual Gas quality specification at the Utility's receipt points and area of influence for purposes of determining impact on a Btu District.

   c. Current and expected future composition of Gas supplies at the Utility's Receipt Points for the purpose of determining interchangeability on customers' end use equipment and the pipeline system's future capability to accommodate supplies.

   d. Potential for increased internal corrosion threat at and through the Receipt Point, Receipt Point pipeline lateral and receiving pipelines due to Gas composition.

   e. Current and future customers in receiving pipeline flow rate, distance to these customers, time to first receiving customer, and anticipated downstream Gas demand growth.

   f. Maximum time and distance required for complete mixing to occur under all pipeline flow conditions. N

L. Pipeline Blending Exception Study (Blending Study) (Continued) N

3. Utility Evaluation (Continued)
   g. The design, operation, and overall condition of the receiving pipeline(s), including any sensitivities to Gas Constituents.

   h. Additional monitoring, control, and/or mixing equipment that may be required to verify and ensure that adequate blending has occurred in the receiving pipeline system.

   A request for gas quality exception will be undertaken as part of the Interconnection Screening or subsequent Preliminary and Detailed Engineering Studies upon receipt of all requested information. The evaluation will be completed within 30 additional business days.

4. Utility Report
   Utility shall provide the Interconnector, within thirty (30) business days, with the acceptance or denial of blending request with the associated Interconnection Screening or subsequent Preliminary and Detailed Engineering Studies.

   The Utility will notify the Energy Division of each request for exception, and state whether the request is granted or denied along with reason for denial.

   a. Acceptance
      For each granted request, the Utility shall provide a determination of the following:

      i. Volumetric flow rate: Authorized volume for blending, or a specific volume that is less than requested, and the conditions under which flow will be limited or otherwise restricted;

      ii. Length of time authorization valid: How long authorization for blending in the pipeline is valid before it must be re-evaluated; and

      iii. Special conditions: Any restrictions, special conditions, and/or special equipment, as determined by the Utility, required to grant acceptance.

   b. Denial
      If denied, a written explanation of the basis for denial and all engineering evaluations and calculations prepared to evaluate the request will be provided to the Interconnector. The explanation may include, but not be limited to:

      i. Historical pipeline flow profiles and proposed Interconnector flow. N

(TO BE INSERTED BY UTILITY) ISSUED BY (TO BE INSERTED BY CAL. PUC)
ADVICE LETTER NO. 5697 **Dan Skopec** SUBMITTED Sep 28, 2020
DECISION NO. 20-08-035 Vice President EFFECTIVE Oct 28, 2020
39C18 Regulatory Affairs RESOLUTION NO.

(Continued)

L. Pipeline Blending Exception Study (Blending Study) (Continued) N

4. Utility Report (Continued)

b. Denial (Continued)

iii. Customer and/or safety impact.

Information is subject to a non-disclosure agreement for confidential information, if any.

5. Utility Right to Re-evaluate and Rescind Blending
The Utility shall have the continuing right at any time to re-evaluate, revise, and potentially rescind, the granted exception allowing for blending in the pipeline due to insufficient flow, ongoing operations, changes in the way the Utility manages the operation of its system, or requirements in accordance with the Utility's CPUC-approved tariffs.

M. Discontinuance and Termination
Discontinuance of use and/or termination will be administered pursuant to the terms of the Interconnector and Utility interconnection agreement.

N. Dispute Resolution

1. The Commission shall have initial jurisdiction to interpret, add, delete, or modify any provision of this Rule and/or tariff ("Interconnection Tariff") and to resolve disputes regarding Utility's performance of its obligations under the Interconnection Tariff pursuant to this Rule.

2. Any dispute arising between Utility and Interconnector (individually referred to as "Party" and collectively "the Parties") regarding Utility's or Interconnector's performance of its obligations under the Interconnection Tariffs shall be resolved according to the following procedures:

a. The dispute shall be documented in a written notice by the aggrieved Party to the other Party containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express written notice by the aggrieved Party that it is invoking the procedures under this Section. The written notice shall be sent to the Party's email address and physical address set forth in any interconnection agreement between the Parties or the Interconnection Request, if there is no interconnection agreement. The receiving Party shall acknowledge the written notice within ten (10) Days of its receipt. N

(Continued)

(Continued)

N. Dispute Resolution (Continued) N

b. The Parties shall negotiate in good faith to resolve the dispute. If a resolution is not reached in forty-five (45) Days from the date of the written notice, either 1) a Party may request to continue negotiations for an additional forty-five (45) Days or 2) the Parties may by mutual agreement make a written request for mediation to the Alternative Dispute Resolution (ADR) Coordinator in the Commission's administrative law judge (ALJ) Division. The request may be submitted by electronic mail to adr_program@cpuc.ca.gov. The dispute and its resolution shall be governed by the Commission's ADR rules and procedures. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

3. If resolution is not reached pursuant to this Section N., either Party may file a formal complaint before the Commission pursuant to California PUC section 1702 and Article 4 of the Commission's Rules of Practice and Procedure. Nothing in this section shall be construed to limit the rights of any Party to exercise rights and remedies under applicable Commission decision, order, rule or regulation.

4. Pending resolution of any dispute under this Section, the Parties shall proceed diligently with the performance of their respective obligations under the Interconnection Tariffs, unless the related agreements have been terminated. Disputes as to the Interconnection Request and implementation of this Section shall be subject to resolution pursuant to the procedures set forth in this Section.

5. Guidance can be provided in letter form by the Director of Energy Division or designated delegate.

6. Notwithstanding anything to the contrary set forth in this Section N, if Utility and Interconnector are parties to one or more of the agreements relating to the interconnection to the Utility's pipeline system, and any such agreement(s) includes a dispute resolution procedure, the dispute resolution procedure set forth in such agreement(s) shall control over the dispute resolution procedure set forth in this Section N. N