Rule 1118.1 – Control of Emissions from Non-Refinery Flares

Final Beneficial Use Technical Assessment

Alternatives to Gas Flaring





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South Coast Air Quality Management District

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Introduction

This technical assessment of the beneficial use of flare gas will examine the benefits of utilizing the gas generated from certain industries and processes that would otherwise be flared. Besides the benefits, this assessment includes an evaluation of emission reductions, avoiding costs, potential revenue, and other incentives. Along with the benefits, this assessment will evaluate the challenges that exist, including systematic issues, legal constraints, and regulatory hurdles.

There is a significant amount of information and studies already available on the beneficial use of gas that would otherwise be flared, and this document will serve as a clearinghouse for the existing data and studies. Specific references and links to those studies can be found in the References section of this document.

Purpose

The purpose of this technical assessment is to be an informative guide for the owners or operators of facilities subject to the requirements of South Coast Air Quality Management District (South Coast AQMD) Rule 1118.1 – Control of Emissions from Non-Refinery Flares (Rule 1118.1) who are seeking alternative strategies to flaring the gas. The intent of the assessment is to provide information on the benefits and potential impediments to various alternative beneficial uses for each industry sector. It is a comprehensive guide but not exclusive as new future technologies and alternatives to flaring will continue to be developed over time.

Background

On January 4, 2019, the South Coast AQMD adopted Rule 1118.1 that applies to facilities that operate non-refinery flares located at landfills, wastewater treatment plants (WWTPs), oil and gas production facilities, organic liquid loading stations, and tank farms. There are 424 flares subject to Rule 1118.1, including 187 landfill gas flares, 83 digestive gas flares located at wastewater treatment plants, 100 produced gas flares located at oil and gas sites, and 54 flares located at other regulated facilities regulated under this rule. Rule 1118.1 established the requirements to reduce Nitrogen Oxides (NOx) and Volatile Organic Compounds (VOC) emissions from non-refinery flares and to encourage alternative acts to flaring gas (e.g., beneficial use), such as energy generation, transportation fuels, or pipeline injection. To encourage beneficial use of flare gas and discourage routine flaring, the rule establishes industry specific capacity thresholds for existing flares. The capacity thresholds serve as a metric to identify routine flaring occurrence at open flares and flares that combust digester gas, landfill gas (LFG), and gas produced at oil and gas production facilities. Any flare that operates at a level greater than the applicable capacity threshold defined by Rule 1118.1 is required to either reduce the level of flaring to below the capacity threshold (e.g., implement beneficial use of the gas that would otherwise be flared) or replace the flare with a unit that complies with a lower NOx emissions limit.

Upon adoption of the rule, the Governing Board directed staff to conduct a technical assessment of various technologies, techniques, approaches, and the associated costs to beneficially use the flared gas to reduce flaring and its corresponding emissions. This technical assessment will reference, but not duplicate, existing reports, or documents, and will build upon existing data to create a unique and expanded technical assessment of the beneficial use of flare gas for facilities within the South Coast AQMD's jurisdiction.

The technical assessment shall identify reliable technologies that promote energy production or transportation fuels and includes a discussion on the NOx emissions and costs of the different technologies. The technical assessment will evaluate technologies most applicable to the type of the generated flare gas, considering:

- Estimated NOx emissions and relative costs
- Challenges (e.g., legal or regulatory hurdles)
- Potential systematic issues (safety/reliability)
- Incentive Opportunities

In accordance with the 2022 AQMP, South Coast AQMD is seeking to require the application of zero-emission technologies in any industry where feasible. Combustion operational practices will be allowed in areas where zero-emission technologies are not feasible, however, South Coast AQMD will continue to encourage the beneficial use of the gas that is produced at the facilities subject to Rule 1118.1 as an alternative to combusting the gas in a flare.

Potential Alternatives to Flaring Gas

Flaring typically emits NOx and other greenhouse gases emissions; therefore, taking advantage of more environmentally friendly alternatives contributes to reducing the associated emissions of both ozone and greenhouse gases. However, some sources such as medium to small oil fields produce significantly more stranded gas than can be consumed onsite at the oil fields itself, presenting unique challenges to harnessing generated gas. Flare throughput reduction can be achieved by harnessing and conditioning the waste gas for a variety of uses. Alternatives to flaring the gas include: 1) energy generation through utilizing the gas in fuel cells to create electricity and hydrogen or using the gas to run micro-turbines or boilers to create power for use at the facility or to generate heat in anaerobic digesters; 2) use as transportation fuel through selling the gas to be used in transportation or converting the gas to liquids for transportation; and 3) inject the gas into natural gas pipelines.

Implementation of alternatives to gas flaring helps to reduce flaring at target industries; however, backup flares and/or other control equipment may be required even when beneficial use technologies are being implemented. Also, staff acknowledges that facilities might have different capabilities to implement beneficial use projects with respect to space availability or access to necessary infrastructure. Therefore, even though a beneficial use technology or project is compatible with specific source category, not all facilities under that category may be able to take advantage of such beneficial use option.

Alternatives to flaring have their specific challenges, but one of the major challenges among different alternatives is that on-site gas clean-up of biogas, e.g., LFG and digester gas, is costly as most associated equipment requires the gas to be cleaned up. The level of contamination in LFG and digester gas at different facilities is site-specific and may change over time. As a result, not all energy recovery options may be possible or cost-effective at every facility. There are companies that operate portable equipment designed to clean up the gas on-site before selling the product to third party customers and can support the beneficial use of flared gas in short-term. However, long-term beneficial use projects would likely be more cost-effective with the installation of permanent gas clean-up technologies to be permitted and operated on-site.

There are also challenges related to specific types of facilities. For example, essential consideration of built in redundancies of emission control equipment/technology, including flares or beneficial use alternatives, is necessary to maintain a reliable and safe operation at wastewater treatment plants and landfills, due to the continuous stream of gas.

There is a wealth of existing information on alternative technologies to flaring in the Staff Report for Proposed Rule 1118.1. The current report will briefly describe several technologies which are the focus of this assessment. This is not an all-inclusive list and not all the discussed technologies will be suitable for every facility, the purpose is to provide information that could be useful for facilities striving to reducing flaring at their facility.

ENERGY GENERATION

Energy generation is an alternative to flaring that is commonly used by facilities with energy intensive operations due to its potential cost savings at specific sites. Energy generation technologies include microturbines, engines, fuel cells, microgrids, and combined heat and power systems.

There are environmental and economic benefits associated with the use of LFG or digester gas as a source of renewable energy to the energy portfolio, including:

- Generating energy that produces no greenhouse gas emissions from fossil fuels and reduces some types of air pollution;
- Diversifying energy supply and reducing dependence on imported fuels; and
- Creating economic development and jobs in manufacturing, installation, etc.

A brief description of some key technologies for generating energy is included below:

Microturbines and Turbines

Microturbines and turbines can be powered by the gas that would otherwise be flared to generate power. In general, microturbines and turbines can be used at each of the source categories subject to Rule 1118.1. An example of using microturbines to generate power is Biosolids and Energy Recovery Facility at Irvine Ranch Water District, located in Irvine, California, which operates a biosolids-to-biogas plant as a scrubbing system to purify the digester gas to run through the microturbines.

Figure 1. Irvine Ranch Water District
(Image Credit: Informed Infrastructure)

Microturbines and turbines are sources of NOx emissions, but modern units with NOx control technologies can be low emitting. Microturbines can also be portable, allowing flexible use without investing in permanent infrastructure as facility needs change, but site specific (fixed location) permits for LFG combustion equipment is required by South Coast AQMD.

Fuel Cells

Fuel cells use a chemical reaction, rather than combustion, to generate electricity. They have high electrical efficiency (30 to 70 percent) and produce zero to very low level of NOx emissions. Fuel cells can utilize LFG, digester gas, or produced gas as the fuel, but the contaminants, especially the siloxanes and sulfur in LFG and digester gas, must be removed as they will poison the catalyst. Fuel cells represent a great opportunity for beneficial use of flare gas and NOx emission reductions; however, the technology and the associated gas clean-up is costly.

Combined Heat and Power

Combined heat and power (CHP) can be an efficient technology that generates additional electricity compared to the electricity generated by a gas turbine through capturing the heat, that would otherwise be wasted, to provide useful thermal energy, such as steam or hot water. Nearly two-thirds of the energy used by conventional electricity generation is wasted in the form of heat discharged to the environment.

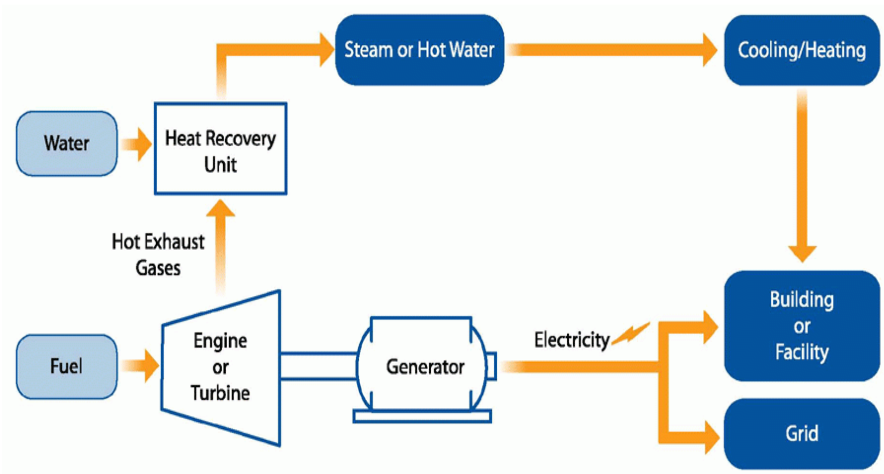


Figure 2. Illustration of Combined Heat and Power Technology

Barriers to Energy Generation

Although price competitiveness is the best-known barrier to renewable energy installations, in many cases, the primary barriers to expanding renewable energy are regulatory and are within state control. Some examples include:

- **Utility Rate Structures**

  Unfavorable utility rate structures have been a perennial barrier to increased deployment of renewable energy technologies. Unless carefully monitored to encourage the development of distributed generation, rate structures can increase the cost of renewables (e.g., through stand-by rates, lack of net metering) or cause prohibitive conditions that prevent their connection to the electrical grid.

- **Lack of Interconnectivity Standards**

  The absence of standard interconnection rules, or uniform procedures and technical requirements for connecting renewable energy systems to the electric utility's grid often make it difficult, if not impossible, for renewable systems to connect to the electric utility's grid.

- **Challenges in Environmental Permitting**
  Large-scale renewable energy technologies are subject to the same necessary environmental permits as major industrial facilities. Plus, renewable energy generation using new technologies may face additional permitting hurdles until permitting officials become more familiar with the technologies associated with renewable energy projects and their environmental impacts. While the permitting process is necessary to implement the requirements of the federal and state Clean Air Act (CAA), the Air Quality Management Plan, and air quality rules and regulations, the process could be a more complicated challenge for smaller facilities looking for alternatives to flaring, though any facility installing a flare would also be required to go through the permit process.

- **Lack of Transmission Infrastructure**
  Many renewable resources are located in remote areas where they lack the ready or cost-effective access to transmission. The development of utility–scale renewable projects may be slow if there is no clear and coordinated planning and permitting processes or no established clear utility regulations that encourage investments in transmission to be reimbursable (i.e., cost recovery).

Distribution of Generated Energy

Generated energy could be used onsite to meet the electrical demands of the facility or other onsite uses. Any power not utilized onsite would be available for export to the grid. In California, surplus cogenerated electricity, which is exported to the public grid, is assumed to displace the California marginal portfolio mix of electrical power generating assets. At the facilities where biogas electricity generation projects are feasible to be implemented, these projects can save customer costs and have the potential to displace other power generating assets. Such projects may include long-term contracts with customers to whom they directly supply electricity onsite or can include contracts with community choice aggregators (CCAs).

TRANSPORTATION FUEL

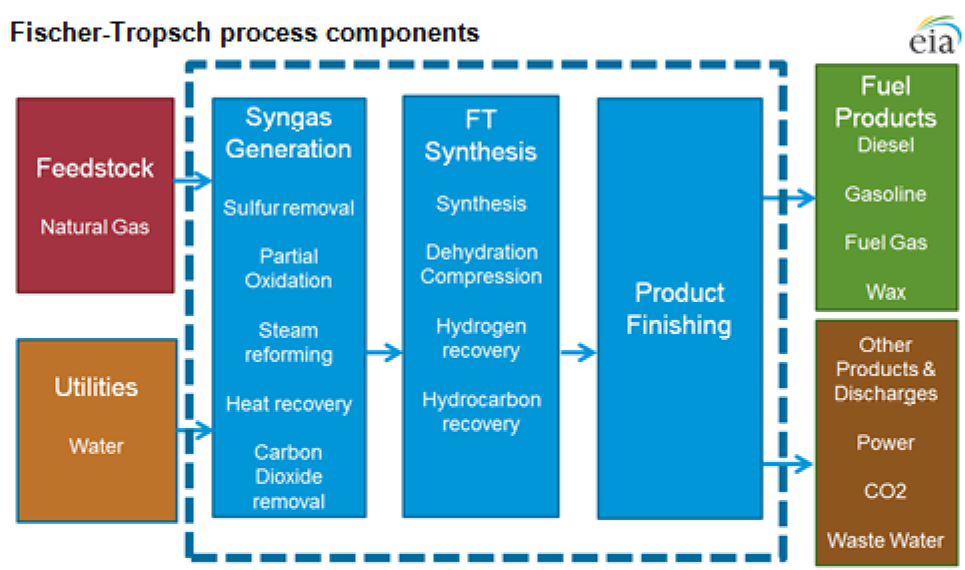
LFG and digester gas can be upgraded to biomethane and be used for vehicle fuel applications as renewable compressed natural gas (R-CNG) or renewable liquid natural gas (R-LNG). The use of upgraded LFG or digester gas for vehicles can be an attractive alternative to distribution of generated power (primarily because air emissions are transferred to the vehicle, simplifying the local air permitting process) and is possibly economical (due to the established markets that provide greater incentives). Also, renewable gases can be used to generate electricity and recharge battery electric vehicles (BEVs).

There is also emissions benefit in converting LFG and digester gas to R-CNG or R-LNG. When natural gas displaces diesel as vehicle fuel, estimated emissions reductions of 60 to 85 percent for NOx, 10 to 70 percent for CO, and 60 to 80 percent for particulates may be realized. Additionally, non-methane VOC emissions and the ozone forming potential decrease by an estimated 50 percent. Challenges of producing vehicle-grade R-CNG and R-LNG include cleaning LFG or digester gas and upgrading it to biomethane. Moisture, siloxanes, sulfur, carbon dioxide, and hydrogen sulfide (and possibly other contaminants) are cleaned from the gas which is then upgraded to biomethane (which typically contains more than 88 percent methane). Oxygen content will have to be closely monitored and adjusted to avoid gas mixtures that permit explosions to occur.

Gas-to-liquids Process

Gas-to-liquids (GTL) is a process that converts natural gas to liquid fuels such as gasoline, jet fuel, and diesel. GTL can also make waxes. The most common technique used at GTL facilities is Fischer-Tropsch (F-T) synthesis. Although F-T synthesis has been around for nearly a century, it has attracted increased interest recently because of the high value of petroleum products and the relatively low cost of natural gas.

The first step in the F-T GTL process is converting the natural gas, which is mostly methane, to a mixture of hydrogen, carbon dioxide, and carbon monoxide. This mixture is called syngas. The syngas is cleaned to remove sulfur, water, and carbon dioxide to prevent catalyst contamination. The F-T reaction combines hydrogen with carbon monoxide to form different liquid hydrocarbons. These liquid products are then further processed into liquid fuels using different refining technologies. F-T GTL process has not been demonstrated at a facility that generates LFG or digester gas, but it may be an applicable process at such facility given the high percentage of methane in these types of biogases.



Source: U.S. Energy Information Administration

Figure 3. Fischer-Tropsch Process

Barriers to Transportation Fuel

Using biomethane, LFG, digester gas, and renewable gas as a transportation fuel can be negatively influenced by the producer- and user-specific challenges, such as access to pipeline and transmission lines for distribution, renewable gas proximity and accessibility to vehicle fleets and heavy-duty trucks as end users, inability of renewable gas to compete in the electricity market, and project costs and economies of scale.

There are also regulatory barriers that might disincentivize the use of biomethane and renewable gas for transportation fuel. CARB's Advanced Clean Fleets regulation that seeks to deploy medium- and heavy-duty zero-emission vehicles (ZEV) everywhere feasible and CARB's zero-emission vehicle program that is designed to control the pollutants and greenhouse gas emissions of passenger vehicles in California are examples of potential barrier to this alternative use of flared gas.

PIPELINE INJECTION

Another option for LFG and digester gas utilization is to upgrade and inject it into natural gas pipelines. This choice is ideal in situations wherein the energy and fuel demand at the location of the gas production are either insignificant or are already met by a fraction of the available gas. Injection of upgraded LFG or digester gas into the pipeline takes advantage of the pre-existing network infrastructure and ideally allows 100 percent of the gas to be utilized if it meets specific quality. Such injection requires the installation of certain gas conditioning and upgrading equipment to achieve the pipeline natural gas quality, utility interconnection, and in some cases, gas (i.e., LFG or digester gas) gathering lines. Pipeline injection also allows for more efficient use of LFG and digester gas compared to produced gas, since larger natural gas power generation facilities are much more efficient than the ones which are small-scale, on-site, and distributed.

LFG and digester gas typically have a methane content around 45 to 50 percent and it must be directed to a treatment plant, where a series of steps convert it into renewable natural gas (RNG). RNG, when meets pipeline-quality standards, is a gas that is fully interchangeable with conventional natural gas. As RNG is a “drop-in” replacement for natural gas, it can be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, industrial applications, and transportation. RNG must have a methane content around 96 to 98 percent to be injected into a natural gas pipeline and the carbon dioxide, hydrogen sulfide, moisture, nitrogen, oxygen, and siloxanes must be removed.

An example of a RNG pipeline injection project is the CR&R anaerobic digestion facility in Perris California which is permitted to transport RNG for about 1.4 miles via a high-pressure steel pipe to the SoCalGas interconnection “point of receipt” (as shown in pictures below).

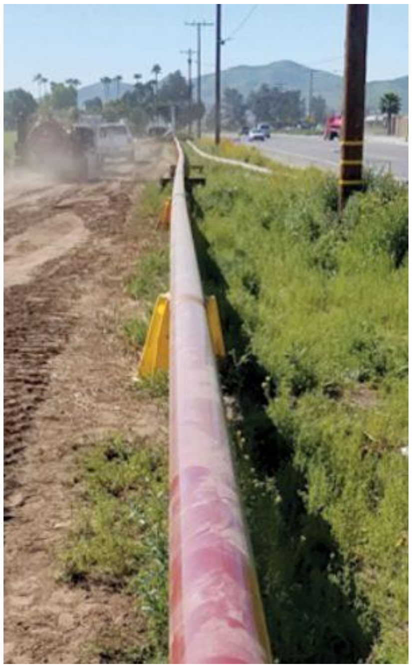


Figure 4. RNG transported with the 1.4-mile pipe (left) and SoCal gas point of receipt (right), Photo courtesy of CR&R Waste and Recycling Services

Barriers to Pipeline Injection

High investment and operating costs, as well as complicated regulatory hurdles (e.g., gas quality standards, gas testing and monitoring requirements, permits) imposed by government agencies and utility companies, have generally limited the availability of pipeline injection alternative to large LFG and digester gas producers with high biomass throughput (i.e., landfills, WWTPs, centralized digester plants) that have the resources to pursue such an endeavor. For example, pipeline injection may be less applicable for the case of landfills due to lower heat content of the LFG which could make it more challenging to meet the pipeline natural gas standards.

Another concern is regarding the local pipeline capacity not being sufficient, especially in more rural locations. Even if there is a pipeline, not all sites can feasibly participate in injection projects since some may not be close enough to gas transmission lines. Moreover, even if there is a pipeline close enough, it may not be able to handle the necessary throughput capacity for injection of LFG or digester gas. However, sites such as oil and gas facilities that do not produce enough gas or are not located near appropriate pipelines for injection could route the gas towards power generation, such as micro-turbines, and/or capture for use in transportation.

There are also regulatory hurdles for the use of biomethane for pipeline injection. For example, any facility that produces methane onsite (in excess of its onsite use) exceeding a specific threshold quantity is subject to Occupational Safety and Health Administration (OSHA) Process Safety Management (PSM) standards. Also, the facility owner is required to prepare and implement a Risk Management Plan pursuant to EPA CAA Risk Management Program (RMP) rule. Challenges caused by the requirements of PSM and RMP program, and the associated costs, may hinder facilities ability to pursue pipeline injection of biomethane as an alternative.

Affected Industries

The technical assessment considers the main sources regulated by Rule 1118.1, which include landfills, wastewater treatment plants, and oil and gas production sites. The figure below (left) provides a breakdown of NOx emissions (averaged over a 3-year period) for each affected source category. The second figure below (right) shows throughput of flared gas, also averaged over a 3-year period. The category with the largest emissions from flaring and the largest flare throughput is by a large margin landfill when compared to the other non-refinery industries.

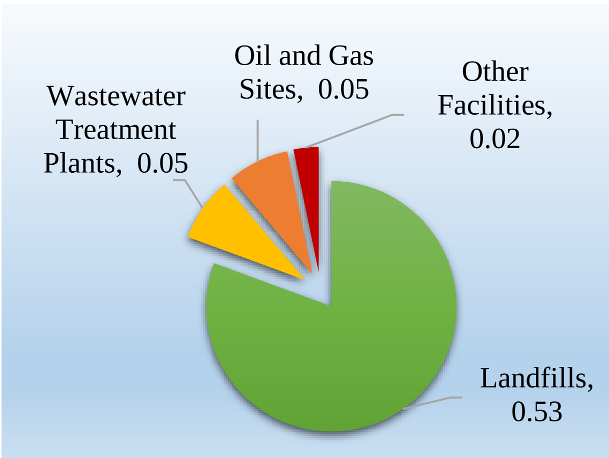


Figure 5. NOx Emissions (tpd) – three-year average (2020-2022)

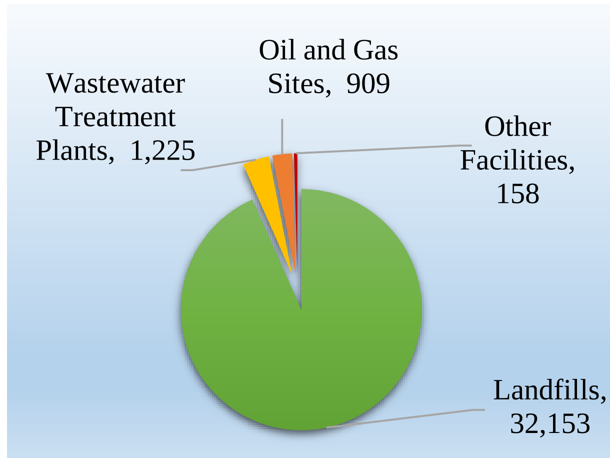


Figure 6. Flare Throughput (MMscf/year) – three-year average (2020-2022)

LANDFILLS

Landfills generate the largest throughput of flared gas, account for the largest share of NOx emission in the Rule 1118.1 universe and generate landfill gas for many decades, even when they are closed and inactive. Landfill gas is a type of biogas that is produced naturally by anaerobic bacteria in municipal solid waste landfills. This breakdown of organic waste in landfills produces gases and contaminants including methane, carbon dioxide (CO_2), sulfides, siloxane, and VOCs. LFG is primarily composed of two potent greenhouse gases, methane, and CO_2. Landfill gas typically has a methane content around 40 to 50 percent, though every landfill is different in terms of methane content. To capture landfill gas as it is produced, landfills install a system of wells and collectors which is called a landfill gas collection system.

Federal, state, and local regulations require the capture of landfill gas. For example, one of the early action measures included in the 2008 Scoping Plan of AB 32 was the improvement of capturing and collecting LFG at California landfills. This led to the implementation of the Methane Emissions from Municipal Solid Waste Landfills Regulation (LMR), dated June 2010. The LMR requires that owners and operators of active, inactive, and closed municipal waste (MSW) landfills over a certain size that accepted waste after January 1, 1977, undertake certain actions, including installation of gas collection and control systems. This creates the potential to retrieve several million cubic feet of LFG per landfill per day, which can be pulled from beneath a landfill through the gas collection and control system and then be combusted through a flare or be used beneficially if gas quality meets the requirements for applicable beneficial reuse options. For examples, the

LFG can be directed to a treatment plant, where a series of steps convert the gas into RNG, or it can be sent to equipment capable of cleaning and conditioning the LFG for power generation purposes, like creating electricity using micro-turbines. Other potential beneficial uses of landfill gas include power generation using steam turbines, internal combustion engines (ICE), and fuel cells; use as transportation fuel; or pipeline injection.

The quality of landfill gas varies at each landfill and can decompose at different rates, depending on pressure and temperature. Besides the quality of LFG, there are differences among landfills with respect to amount of contamination in LFG (which changes over time based upon the composition of the waste stream), variation in the amount of gas available for any beneficial use, and closure date of the landfill. Overtime, landfills experience a decrease in quantity of gas and quality of heat content (measured as British thermal units per standard cubic foot or Btu/scf) until eventually neither flaring nor beneficial use is feasible. For example, the landfill gas produced at closed landfills has a low heat content which diminishes overtime and generates additional challenges for beneficial use of LFG. Other challenges associated with LFG include a low heat content ranging from 400 to 500 Btu/scf, and the high expense to remove siloxane contaminants, which can damage equipment or poison the catalyst used to control NOx emissions.

Landfills are not energy intensive operations. However, due to the large quantity of landfill gas consistently being produced at active landfills, such landfills can beneficially use LFG to generate energy that powers onsite uses or provides power to surrounding users.

WASTEWATER TREATMENT PLANTS

At wastewater treatment plants, digester gas is produced through anaerobic decomposition in digester units, which is a type of flammable biogas composed of methane, hydrogen sulfide, CO_2, and siloxane. This source category generates the second largest volume of flared gas and is expected to increase proportionally due to organic waste diversion efforts mandated by state law.

Senate Bill 1383 – Short-Lived Climate Pollutants (Methane Emissions, Dairy and Livestock, Organic Waste, and Landfills) was approved in 2016 and seeks to reduce organic waste methane emissions from landfills. Such reductions require food wastes, currently being disposed at landfills, to be diverted to anaerobic digesters or composting facilities. As organic waste is diverted away from landfills, additional digester gas is anticipated to be produced at wastewater treatment plants and other digesters that receive the organic waste.

Similar to landfill gas, the removal of siloxane contaminate is a challenging and costly process for digester gas. In general, wastewater treatment plants have different concentrations of contaminants which may cause potential site-specific limitations.

Digester gas is relatively low on heat content compared to produced gas but has relatively higher heat content compared to landfill gas, ranging from 500 to 600 Btu/scf. Wastewater treatment facilities have a high energy demand; therefore, many facilities can utilize the digester gas for power generation using turbines, micro-turbines, internal combustion engines (ICE), or boilers to make steam for heating digesters.

Oil and Gas Production Sites

The third category subject to Rule 1118.1 with the largest volume of flare gas is oil and gas production sites. The flare gas at these sites if called produced gas which is the biproduct of oil extraction. Many oil and gas sites that produce significant quantities of gas have incorporated beneficial use alternatives to reduce the amount of gas flared. Due to the high quality of produced gas, there are considerable opportunities for beneficial use, including pipeline injection and energy production (e.g., turbines, fuel cells, etc.). While some sites are remote without a large energy demand, others are energy intensive, making it more cost effective to implement beneficial use projects that provide energy either onsite or to surrounding areas.

In addition to oil production, the oil extraction process produces gas, water, and other contaminants. The produced gas is naturally occurring and has relatively high heat content (around 900 Btu/scf) but requires gas treatment to remove sulfides, water, CO_2, and other contaminants.

Some facilities beneficially use the produced gas to generate energy or inject the gas into pipeline. Pipeline injection is cost effective for companies that have connections nearby or can inter-connect to another company's pipeline or through a municipal connection. Produced gas in not considered RNG, so incentives are not available to assist with its conversion or capture; however, the Southern California Gas Company has a tariff program to assist companies generating produced gas with installing skid-mounted units for gas clean-up and developing connection to existing natural gas pipelines. In addition, there are opportunities to use the produced gas to generate energy through fuel cells and micro-turbines as well as to consume as transportation fuel.

Assessment of Potential Alternatives to Gas Flaring

Table 1 compares the three primary potential alternatives to gas flaring: energy generation, transportation fuel, and pipeline injection. The assessment considers emissions, estimated costs, potential challenges, and technologies that can use the gas beneficially in lieu of flaring.

Table 1. Potential Alternatives to Flaring Gas

	Energy Generation	Transportation Fuels	Pipeline Injection
Technology	- Microturbines - Fuel cells - Combined Heat and Power	- Compressing gas to CNG or LNG - Gas to Liquid - Gas to Hydrogen	N/A
NOx Emissions Evaluation	- Emissions from heat and power generation - Emission savings from displacing existing heating	- NOx emissions generated - NOx emissions offset from fuel displacement (GREET model)	- NOx emissions generated - NOx emissions offset from gas displacement
Costs and Revenue	- Additional gas clean-up - Energy generation equipment - Total install cost (TIC) and O&M - Potential energy/heat cost savings - Potential revenue from sales to the grid	- Additional gas clean-up/upgrade - New equipment - TIC and O&M - Revenue and incentives - Cost saving from fueling existing fleet	- Additional gas clean-up/upgrade - New equipment - TIC and O&M - Connection to pipeline - Revenue and incentives
Legal or Regulatory Hurdles	- California Public Utilities Commission (CPUC) (e.g., 1 MW restriction) - Permitting - California Environmental Quality Act (CEQA) - Land use (local) approval - Political will - Other regulations (e.g., state GHG goals)	- Permitting - CEQA - Land use (local) approval - Political will - Other regulations (e.g., state GHG goals)	- Permitting - CEQA - Land use (local) approval - Political will - Other regulations (e.g., state GHG goals, OSHA PSM, EPA RMP)
Other Challenges	- Infrastructure (electric grid) - Utilities charges + restrictions (demand charge) - On-site gas cleanup - Transmission - Gas quality/quantity	- Infrastructure (dispensing) - On-site gas cleanup - Transmission - Gas quality/quantity	- Infrastructure (pipeline) - Trucking to end user (if no pipeline) - On-site gas cleanup - Transmission - Gas quality/quantity

Incentives

Market-based incentives are available to encourage the beneficial use of digester gas from wastewater treatment plants and landfill gas (but not produced gas, which is not considered RNG). Wastewater treatment plants and landfills constantly generate low-quality gas often with about half the heating value of pipeline quality natural gas and with significant contamination. The most problematic contaminants are siloxanes, which are used in a variety of personal care products, such as deodorants, shampoos, skin creams, and hair styling products. Siloxanes are costly to remove from the gas stream and are harmful to combustion equipment and post-combustion control equipment used to control NOx emissions, such as selective catalytic reactors. Federal and state market-based programs provide incentives for alternative use of flared gas. A list of incentives can be found below:

- California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS) (https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard)
  The LCFS is designed to encourage the use and production of cleaner low-carbon transportation fuels in California, to reduce GHG emissions, and to decrease petroleum dependence in the transportation sector. CARB is is expected to phase out this incentive aligned with the endeavors to meet California's health-based air quality standards and greenhouse gas emission reduction goals through zero-emission technologies and the zero-emission vehicle (ZEV) program.

- U.S. EPA Renewable Fuel Standard/Renewable Identification Numbers (RINs) (https://www.epa.gov/renewable-fuel-standard-program/renewable-identification-number-rin-data-renewable-fuel-standard)
  The Renewable Fuel Standard (RFS) program is implemented by the EPA in consultation with U.S. Department of Agriculture and the Department of Energy. The RFS program is a national policy that requires a certain volume of renewable fuel to replace and reduce the quantity of petroleum-based transportation fuel, heating oil, or jet fuel. The four renewable fuel categories under the RFS are:
  - Biomass-based diesel
  - Cellulosic biofuel
  - Advanced biofuel
  - Total renewable fuel

- SoCalGas Biogas Conditioning/Upgrading Services (BCUS) Tariff Program (https://www.socalgas.com/for-your-business/power-generation/biogas-conditioning-upgrading)
  The BCUS Tariff is an optional tariff service for customers that allows SoCalGas to plan, design, procure, construct, own, operate and maintain biogas conditioning and upgrading equipment on customer premises. Examples of customer end-use applications that can be served by the BCUS Tariff include but are not limited to renewable natural gas for pipeline injection, CNG for vehicle refueling stations, and conditioned/upgraded biogas for CHP facilities. The BCUS Tariff is a fully elective, optional, nondiscriminatory 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 way these services are delivered.

- Advanced Transportation Tax Exclusion (https://www.treasurer.ca.gov/caeatfa/ste/index.asp)
  Senate Bill 71[1] of 2010 established a sales-and-use tax exclusion (STE) for eligible projects on property utilized for the design, manufacture, production or assembly of advanced transportation technologies or alternative source (including energy efficiency) products, components, or systems. The California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) is administering the program.

- Senate Bill 100 – Zero Carbon Electricity by 2045 (https://www.energy.ca.gov/sb100)
  This policy requires California's renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers and 100 percent of electricity procured to serve state agencies by December 31, 2045. The policy also requires that the transition to a zero-carbon electric system does not cause or contribute to increases of greenhouse gas emissions elsewhere in the western electricity grid. Senate Bill 100 (SB 100) requires the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and CARB to submit a joint agency report to the Legislature evaluating the 100 percent zero-carbon electricity policy.

- Executive Order B-55-18 Carbon Neutrality by 2045 (https://ww2.arb.ca.gov/our-work/programs/local-actions-climate-change/local-government-actions-climate-change)
  California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative GHG emissions thereafter. Achieving this goal would complete a chain of other ambitious statewide targets for reducing greenhouse gas emissions.

- World Bank Zero Routine Flaring by 2030 Initiative (https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030)
  The World Bank's international Global Gas Flaring Reduction Partnership (GGFRP) is a public-private partnership with the aim of retiring the wasteful practice of flaring by ending routine gas flaring at oil production sites across the world. In 2015, The World Bank further launched the Zero Routine Flaring by 2030 Initiative, which was endorsed by 32 countries, 37 companies, and 15 banking institutions by the end of 2019.

- Self-Generation Incentive Program (SGIP) (https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program)
  The CPUC's Self-Generation Incentive Program (SGIP) provides incentives to support existing, new, and emerging distributed energy resources. SGIP provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems. Fuel cell projects that generate electricity for on-site use are eligible for funding under SGIP.

[1] http://leginfo.ca.gov/pub/09-10/bill/sen/sb_0051-0100/sb_71_bill_20100324_chaptered.pdf

- Senate Bill 1122 – Bioenergy Market Adjusting Tariff (BioMAT) (https://www.pge.com/en_US/for-our-business-partners/floating-pages/biomat/biomat.page?WT.mc_id=Vanity_rfo-biomat&ctx=large-business)
  In-state electricity generation from renewable gas has faced several barriers that have decreased cost competitiveness. For this reason, the Bioenergy Market Adjusting Tariff (BioMAT) was created to support small in-state bioenergy generators of 5 megawatts capacity or smaller that export no mor ethan 3 megawatts electricity to the state's largest three investor-owned utilities. The BioMAT program secures an additional capacity of up to 250 megawatts to eligible bioenergy projects, which includes electricity generation using digester gas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, through a fixed-price standard contract to export electricity to California's three large investor-owned utilities.

- Other resources which encourage the beneficial use of flared gas are as follows:
  - Partnerships with other entities
    State law predominantly relies on a design-bid-build (DBB) project delivery method to design and build infrastructure projects. Often referred to as a "traditional" delivery method, most Caltrans' projects are delivered using DBB, where the public sector retains most of the risk for design, permitting, and right of way. Project delivery methods that transfer certain responsibilities for project delivery from the public sector to the private sector include design-build, construction manager/general contractor (CM/GC), and Public-Private Partnership (P3).
  - Potential future developments for energy/fuel incentives (https://www.energy.ca.gov/programs-and-topics/topics/renewable-energy)
    Senate Bill 350 (SB 350) increases California's renewable electricity procurement goal from 33 percent by 2020 to 50 percent by 2030. This objective will increase the use of Renewables Portfolio Standard (RPS) eligible resources, including solar, wind, biomass, geothermal and others. SB 350 also requires the state to double statewide energy efficiency savings in electricity and natural gas end uses by 2030.
  - California laws and incentives related to alternative fuels (https://afdc.energy.gov/laws/all?state=CA)

Conclusion

It is the goal of the South Coast AQMD and intent of this technical assessment to provide a guidance document that industry can refer to for new ideas and incentives to handle flare gas more beneficially in the future. The assessment presents potential alternatives that beneficially use flare gas at landfills, wastewater treatment plants, and oil and gas sites based on their feasibility, cost, and emission impacts. Staff discusses the hurdles to beneficial use of flare gas at facilities with routine flaring that are not beneficially using flare gas to the maximum extent feasible. Through beneficial use of flared gas, businesses can find ways to save costs, gain a co-benefit, generate revenue, and contributing to a healthier clean air environment.

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