DOCKETED

Docket Number:	19-IEPR-06
Project Title:	Energy Efficiency and Building Decarbonization
TN #:	229845
Document Title:	Southern California Gas Company Comments - SoCalGas Comments on EE and Building Decarbonization
Description:	N/A
Filer:	System
Organization:	Southern California Gas Company
Submitter Role:	Public
Submission Date:	9/24/2019 5:01:52 PM
Docketed Date:	9/25/2019

Comment Received From: Southern California Gas Company
Submitted On: 9/24/2019
Docket Number: 19-IEPR-06

SoCalGas Comments on EE and Building Decarbonization

Additional submitted attachment is included below.

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September 24, 2019

California Energy Commission
Dockets Office, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: Comments on the IEPR Joint Agency Workshop on Energy Efficiency and Building Decarbonization & *2019 California Energy Efficiency Action Plan Draft Staff Report*, Docket #19-IEPR-06

Southern California Gas Company (SoCalGas) appreciates the opportunity to comment on the *2019 California Energy Efficiency Action Plan Draft Staff Report* (Draft EE Action Plan) as well as the California Energy Commission's (CEC) and California Public Utilities Commission's (CPUC) Joint Agency Workshop on Energy Efficiency and Building Decarbonization held on August 27, 2019 as part of the 2019 Integrated Energy Policy Report (IEPR) proceeding.

SoCalGas fully supports a plan that will reduce greenhouse gas (GHG) emissions from buildings. However, fixating on a one-track solution, such as electrifying end uses, can lead to missing more affordable and better solutions to address climate change. SoCalGas reiterates our concern about the pro-electrification bias of this year's IEPR proceeding. The joint agencies should support an inclusive energy strategy that objectively considers all options and encourages and allows for current and future innovation. This year's IEPR must include recommendations that address the State's climate goals while maintaining energy reliability, resiliency, affordability, and consumer choice.

Our position on balanced energy solutions has been communicated many times,[1,2,3,4] most recently in our Opening and Response Comments to CPUC's Order Instituting Rulemaking regarding Building Decarbonization (see Attachments A & B, respectively). Additionally,

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[1] SoCalGas Comments on the Final 2018 IEPR Update. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=226490&DocumentContentId=57268

[2] SoCalGas Comments on the Draft 2018 IEPR Update. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=225796&DocumentContentId=56469

[3] SoCalGas Comments on the 2018 IEPR Update Commissioner Workshop on Achieving Zero Emission Buildings. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=224017&DocumentContentId=54244

[4] SoCalGas Comments on the 2019 IEPR Building Decarbonization Workshop held on April 8 2019. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=227834&DocumentContentId=59209

SoCalGas recently released a broad, inclusive, and integrated plan titled, *California's Clean Energy Future: Imagine the Possibilities*, to help achieve California's climate goals.[5]

SoCalGas' balanced energy approach is consistent with the Energy Futures Initiative's study developed by Dr. Moniz, former Secretary of Energy under the Obama Administration, titled, *Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California*, which analyzes the ways California can meet its 2030 and 2050 low-carbon energy goals.[6] The report emphasizes that there is no "silver bullet," all energy infrastructure should be utilized, and renewable gas such as hydrogen will need to be part of California's long-term plan to achieve mid-century goals. The authors also emphasize the need for the State to pursue a building decarbonization strategy that allows California to maintain a diverse portfolio of energy options. The Draft EE Action Plan fails to recognize this need.

The Final 2018 IEPR Update[7] and the Draft EE Action Plan make the unsupported claim that "[t]here is a growing consensus that building electrification is the most viable and least-cost path to zero-emission buildings."[8] While it may seem like there is growing consensus based on the like-minded views of panelists and experts the joint agencies regularly select to participate in workshops, the CEC and CPUC must consider the impact that an all-electric solution may have on customer affordability and adoption throughout all of California. About 90% of residential energy consumers in Southern California use natural gas for space and water heating[9] and expressly prefer a choice in how they heat their homes and cook their food.[10]

When the CPUC proposed to direct SoCalGas to implement a moratorium on new commercial and industrial natural gas connections in Los Angeles County,[11] a number of parties—including Los Angeles County, American Gas Association, Los Angeles County Business Community Coalition, Bloom Energy, California Manufacturers and Technology Association, Biz Fed Los Angeles County, PTG Water & Energy, Californians for Affordable and Reliable Energy, California Council for Environmental and Economic Balance, Clean Energy, and Honeybird Restaurant—strongly opposed the proposal and underscored the economic harm that would be

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[5] SoCalGas Website. Available at: https://www.socalgas.com/vision

[6] Energy Futures Initiative. *Optionality, Flexibility, & Innovation. Pathways for Deep Decarbonization in California.* 2019. Available at: https://energyfuturesinitiative.org/

[7] 2018 Final IEPR Update, P. 21. Available at https://efiling.energy.ca.gov/getdocument.aspx?tn=227391

[8] CEC. *CA 2019 EE Action Plan Draft Staff Report.* P.120. Available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=229496

[9] California Energy Commission "2009 California Residential Appliance Saturation Study: Executive Summary," Table ES-3: Natural Gas UEC and Appliance Saturation Summaries by Utility. October 2010.

[10] Natural Gas Institute. *California Reports Show Homeowners Prefer NatGas Over Electrification*. April 25, 2018. Available at: https://www.naturalgasintel.com/articles/114152-california-reports-show-homeowners-prefer-natgas-over-electrification

[11] CPUC Draft Resolution G-3536, Emergency Order Direction Southern California Gas Company to Implement a Moratorium on New Natural Gas Service Connections. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K367/201367863.PDF

done if it were implemented.[12] The following Chambers of Commerce also have expressed their concern of an all-electric focus of decarbonizing buildings: Los Angeles,[13] Azusa,[14] Pomona,[15] Greater Coachella Valley,[16] Glendora,[17] El Monte/South El Monte,[18] and most recently, Lakeside.[19] Additionally, the Kern County Board of Supervisors,[20] Desert Valleys Builders Association,[21] Biz FED Central Valley Business Federation,[22] and Valley Industry and Commerce Association[23] are against an all-electrification path based on impacts on customers choice, cost, and reliability. These parties encourage the joint agencies to adopt fuel-neutral policies and they collectively represent hundreds of thousands of consumers, clearly showing there is not the consensus on electrification suggested by CEC staff in the Draft EE Action Plan.

Furthermore, CPUC Deputy Executive Director Ed Randolph recently noted that "given the role methane plays in short-lived climate pollutants, it may be critical that the state agencies and industry find a way to make renewable natural gas affordable in playing a role in transportation and/or building sectors."[24] Mr. Randolph's comments raise a critical part of California's plan to meet the 2030 targets. The California Air Resources Board's (CARB) Short-lived Climate Pollutant (SLCP) Reduction Strategy accounts for over one-third of the projected GHG emissions reductions in 2030. The capture of methane from organic sources is almost two-thirds

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[12] Los Angeles Business Journal. January 5, 2018. *Business Opposition Mounts to Proposed Moratorium on New Natural Gas Hookups*. Available at: https://labusinessjournal.com/news/2018/jan/05/business-opposition-mounts-proposed-moratorium-new/

[13] LA Chamber Comments on Decarbonizing Buildings Workshop. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223983

[14] Steven Castro - Azusa Chamber of Commerce Comments on Assembly Bill 3232. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223898

[15] ERICA Frausto-Aguado Comments Electrification Zero Emission Buildings- OPPOSE. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223893

[16] Patrick Swarthout Comments AB 3232. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223879

[17] Glendora Chamber of Commerce, Opposition of electrifying all buildings. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223845

[18] El Monte/South El Monte Chamber of Commerce, Ken Comments AB 3232. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=224013

[19] Lakeside Chamber of Commerce Comments On 2019 California Energy Efficiency Action Plan. 2019 IEPR. 5.17.19. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=228315&DocumentContentId=59501

[20] Kern County - Board of Supervisors Comments On Achieving Zero Emission Buildings. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=224029

[21] Desert Valleys Builders Association, Oppose Proposed Legislation AB 3232. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223844

[22] Biz FED Central Valley Business Federation's Comments Re. Achieving Zero Emissions Buildings. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=224024

[23] Valley Industry and Commerce Association, VICA Comments - Achieving Zero Emission Buildings. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223956

[24] CPUC Deputy Executive Director Randolph at September 12, 2019, CPUC Commission Meeting. Available at: http://www.adminmonitor.com/ca/cpuc/voting_meeting/20190912/

of the reductions envisioned in the SLCP Reduction Strategy.[25] In the Assembly Bill 32 Scoping Plan Update, CARB included renewable gas as a key element of 'Achieving Success in Clean Energy' stating "[r]educe the use of heating fuels while concurrently making what is used cleaner by minimizing fugitive methane leaks, prioritizing natural gas efficiency and demand reduction, and enabling cost-effective access to renewable gas."[26] By focusing exclusively on electrification, the Draft EE Action Plan misses the opportunity to provide pathways to achieve the reductions identified in the SLCP Reduction Strategy and Scoping Plan Update.

California's focus should be on decarbonizing both gas and electric supplies, not just the electric supply. We ask the joint agencies to exclude the statement about consensus on electrification in the Final EE Action Plan and upcoming Draft 2019 IEPR. Additionally, we ask the joint agencies to convene panelists with more diverse backgrounds, ideas, and solutions from different geographical locations to promote a more balanced discussion about meeting GHG goals that will equitably inform the public and policy makers.

In addition to the points made above, SoCalGas offers the following specific comments in response to the August 27th workshop and the Draft EE Action Plan:

1. Joint Agencies Equate Building Decarbonization with Electrification
2. The True Cost of Electrification Has Not Been Analyzed
3. How to Decarbonize the Natural Gas Sector
4. Fuel Switching Exacerbates the Risk of Maintaining Electric Reliability
5. Methane Emissions from Natural Gas System are Overstated by CEC
6. Correction of Claims Regarding Natural Gas Use and Air Quality in Homes
7. Building Decarbonization Strategies Must Prioritize Energy Efficiency

1. Joint Agencies Equate Building Decarbonization with Electrification

SoCalGas is concerned that the joint agencies continue to equate building decarbonization solely with electrification. For example, in the Draft EE Action Plan, under Goal 3: Reducing Greenhouse Gas Emission from Buildings, makes a number of statements that show the joint agencies' bias in support of complete electrification [***emphasis added***]:

- "Effective statewide building decarbonization efforts will seek to increase the share of renewable generation on the electricity grid, ***lower barriers to building electrification,*** and increase energy efficiency, all while coordinating efforts to reduce electricity consumption when the GHG intensity of electricity is highest." (p.121)

8. Regarding 2019 Building EE Standards, "***[t]he benefits provided by electrification include many direct benefits to homeowners and tenants.*** Reductions in on-site combustion, particularly for cooking, directly improves indoor air quality and reduces concentrations of criteria pollutants." (p.125) The latter statement is also factually

[25] CARB. Short lived Climate Pollutant Reduction Strategy. March 2017. Available at: https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf
[26] CARB. *California's 2017 Climate Change Scoping Plan*, adopted November 2017. Available at https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf

incorrect, please see #6, Correction of Claims Regarding Natural Gas Use and Air Quality in Homes below for more information.

- The 2022 Building EE Standards "***update will address additional barriers to building electrification, ensuring that all-electric pathways are available to all types of multifamily construction.***" (p.125)
- "For commercial buildings, ***the CEC must first establish an all-electric baseline***, starting with the most common building types." (p.125)

Additionally, the report recommends the joint agencies "***[c]o-fund electrification in buildings*** with flexible assets in order to optimize integration with DERs, DR, and load shifting capabilities." (p.137)

SoCalGas encourages the CEC to expressly confirm in the Final EE Action Plan and the upcoming Draft 2019 IEPR that building decarbonization can have many pathways, including energy efficiency, electrification, renewable gas use in building end uses, and others.

2. The True Cost of Electrification Has Not Been Analyzed

Even while the joint agencies continue to focus on electrifying buildings, the true cost of electrifying end uses has not been analyzed. For example:

- Issues like how electric utilities recover the costs for the recent wildfires remains unresolved. A recent San Francisco Chronicle article posits that utility costs could double as a result of the fires.[27]
- How much will it actually cost to mitigate the risk of wildfires from electric infrastructure? During the joint agencies' Kick Off Workshop for Senate Bill 100 held on September 5, 2019, Commissioner Randolph said that the proposed investor-owned utility budget to mitigate fire risks in 2020-2021 was $1.7 billion.
- How much will it cost to continue to harden or underground the electric grid?
- What are the public health and economic impacts of electric power outages, which are becoming more common?
- Would increasing the use of heat pumps in the winter and summer increase peak electric load?

Additionally, last year the California Building Industry Association asked Navigant Consulting to study the potential costs customers could incur from switching from a mixed-fuel home to an all-electric one.[28] In Phase I of the study, Navigant looked at existing single-family homes in several Southern California locations. They found that "[s]witching to all-electric appliances

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[27] San Francisco Chronicle. April, 10, 2019. *PG&E electricity rates could double after more wildfires, report says.* Available at: https://www.sfchronicle.com/business/article/California-electricity-rates-could-surge-50-13757757.php

[28] Navigant Consulting. April 19, 2018. The Cost of Residential Appliance Electrification, Phase 1 Report- Existing Single-Family Homes.

would cost California consumers over $7,200 and increase energy costs by up to $388 per year."[29]

SoCalGas is concerned about energy affordability for our customers, especially because low-income households would be the most burdened by high building electrification scenarios. Low-income customers will also be denied options to hedge themselves from power outages with no alternative method to cook their food, run medical equipment, or heat their home. It is imperative that the Final EE Action Plan and the upcoming Draft 2019 IEPR provide flexibility, especially regarding potential costs of actions, such that all regions in California benefit from proposed State actions. For example, energy affordability is a critical issue for the San Joaquin Valley, where the median household income is 25% lower than the State average.[30] There are many other counties that have median incomes well below the State's average. Therefore, consideration and evaluation of cost and affordability should be a high priority at the joint agencies.

3. How to Decarbonize the Natural Gas Sector

During the workshop, Commissioner McAllister asked what the path forward is to decarbonize the natural gas sector. As SoCalGas has expressed in detail in previous comments, the path forward is for the joint agencies to support policies and projects to increase investment in a portfolio of options including carbon capture, utilization, and storage; renewable gas such as those derived from woody biomass that can reduce risks of wildfires; and innovative technologies that support the penetration of renewables in the grid, such as power-to-gas technology.

SoCalGas is committed to being the cleanest natural gas utility in North America and is committed to have 20% renewable gas delivered to our core load by 2030. SoCalGas has submitted to the joint agencies extensive information on the opportunity to utilize the existing, reliable, and resilient natural gas infrastructure with renewable gas[31,32] and hydrogen.[33] Nevertheless, the Draft EE Action Plan dismisses renewable gas as a viable option: "[r]enewable gas can be a part of the solution to reduce GHG emissions from buildings, but the role is likely to

[29] *Ibid.* This analysis does not include the cost of necessary infrastructure upgrades to the local and statewide electricity grid to accommodate the additional load on the system.
[30] Department of Numbers Website. California Household Income. Available at: https://www.deptofnumbers.com/income/california/
[31] SoCalGas comments on Zero Emissions Buildings Workshop. 2018 IEPR Update. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=224017&DocumentContentId=54244
[32] SoCalGas & SDG&E RNG Tariff Application A.19-02-015. CPUC. Available at: https://www.socalgas.com/regulatory/A19-02-015.shtml
[33] Final SoCalGas Comments on Clean Transportation Benefits Report Workshop. 2019 IEPR. 8/8/2019. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=229283&DocumentContentId=60689

be constrained by limitations on its availability, cost, and leakage concerns."[34] This conclusion discounts the value of California's natural gas infrastructure and the need to reduce SLCPs.[35]

The fact is that most of the methane in the atmosphere according to CARB's inventory is from the agriculture and waste sectors. Leakage from natural gas distribution pipelines in the State represents less than 1% of the total GHG inventory and there is a CPUC program to further reduce these emissions under the Senate Bill 1371, "Natural Gas Leakage Abatement" rule.[36] Capturing the methane from the agricultural and waste sectors and delivering renewable gas through the existing natural gas pipeline is the best solution to reduce these emissions and create synergies with rural and disadvantaged communities.

As an example, in the San Joaquin Valley Disadvantaged Communities proceeding, the CPUC requested a study to be completed on the costs and feasibility to create renewable gas for a rural farming community that was burning propane and wood waste. The Black & Veatch study attached showed the local dairy farmer could create enough renewable gas to supply the community as well as sell the extra to displace diesel fuel in agricultural trucks and equipment (see Attachment C). This is a "triple win" solution that supports the local community, farmer, and public health.

We recommend the CEC and CPUC thoughtfully consider all options, including renewable gas from agriculture, waste, and forest woody biomass (e.g. 147+ million dead trees) that can reduce the risk of catastrophic wildfires. Also, according to the Energy Futures Initiative study to meet the mid-century goals, hydrogen and carbon negative solutions, such as methanated renewable hydrogen, provide increased climate benefits by removing carbon from other sectors of the economy while also reducing GHG emissions from the building sector.[37]

A portfolio of options approach is consistent with prudent best practices to manage risk, leverages existing energy infrastructure, sustains well-paying union jobs, and creates flexibility that allows

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[34] CEC. *CA 2019 EE Action Plan Draft Staff Report.* P.120 Available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=229496

[35] CARB's AB 32 Scoping Plan states that methane capture is a key strategy in achieving GHG reductions from the agricultural and waste sectors in order to achieve our ambitious climate change goals and Senate Bill 1383 requires a 40% reduction of methane emissions by 2030. SB 1383 text available at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

[36] SB 1371 text. Available at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1371

[37] RG helps us reduce fugitive emissions by harnessing our waste streams, effectively converting emissions into fuel. The largest source of methane emissions in California (more than 80%) is agriculture, dairies, landfills, and waste water. We can capture this waste; convert it into biogas using anaerobic digestion; process the biogas to make it pipeline ready; inject it into existing pipelines; and use the fuel where natural gas is used. RG can also be made from the woody biomass that is removed from forests to reduce the risk of catastrophic wildfires.

innovative and synergistic solutions across multiple sectors.[38] Yet another benefit, consumers do not have to bear the cost and burden of replacing appliances, retrofitting homes, etc.

SoCalGas also believes California should prioritize the development and use of hydrogen—produced from low- or zero-carbon feedstocks—to play a significant role to facilitate California's decarbonization of the transportation sector across multiple vehicle classes used across diverse economic sectors. To do this, hydrogen will need to be produced from steam reforming using carbon capture, utilization, and storage; from renewable sources, like water electrolysis using carbon-free electricity; and by utilizing renewable gas from landfills and dairy feedstocks. This low- or zero-carbon hydrogen can be used in several applications.

SoCalGas has submitted extensive comments[39,40] on the opportunity for power-to-gas technology[41] to convert surplus renewable energy into hydrogen, which can be blended with natural gas or renewable gas and utilized in everything from home appliances to power plants to vehicles as a transportation fuel.

SoCalGas asks the joint agencies to review SoCalGas' previously submitted letters. We strongly urge the joint agencies to support policies and projects to increase the investment in a portfolio of options such as renewable gas; hydrogen; carbon capture, utilization, and storage; fuel cells; and power-to-gas technology. Our subject matter experts would be happy to work with staff so the agencies have a better understanding of the opportunities and challenges associated with decarbonizing all sectors of the economy.

4. Fuel Switching Exacerbates the Risk of Maintaining Electric Reliability

During the workshop, there was quite a bit of discussion about fuel switching. Commissioners on the dais agreed that the amount of fuel substitution should be increased to help meet energy efficiency and GHG goals. SoCalGas echoes the comments of California Independent System Operator (CAISO) Vice President Rothleder, who said that fuel switching is not always going to drive down electric loads. And we want to remind the joint agencies of the challenge to maintain electric reliability and how natural gas supports that effort.

The Energy Futures Initiative report mentioned above rightly points out that "[p]olicies that affect natural gas in some sectors (e.g., building electrification) may have unintended impacts on other sectors that consume and rely on natural gas. These impacts include price volatility;

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[38] Because the underground infrastructure is resilient to wildfires and other extreme climate and weather events, such as wind storms, microgrids supported by RG could be deployed in high-risk areas.
[39] SoCalGas. Comments in response to the 2015 IEPR Draft AB 1257 Report, the 2017 IEPR Increasing the Need for Flexibility in the Electricity System Workshop held on 5/12/17, and the Draft 2017 IEPR.
[40] SoCalGas Comments - E3's Article, Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=220242&DocumentContentId=29876
[41] SoCalGas Website. Available at https://www.socalgas.com/smart-energy/presentations-webinars/decarbonizing-the-pipeline

relatively higher infrastructure costs for sectors that have limited near-term options for decarbonization; and reduced resource availability."[42]

We also want to point out that the natural gas system in California is safe, reliable, and resilient to climate-related disasters. It is essential for reliable 24-hour electric service, particularly for public safety facilities and vulnerable customers. This point was recently made by Commissioner Shiroma at a CPUC meeting: she said, "we do not yet in 2019, have 24-hour source of electricity that is reliable, even, sustainable, and so forth… Currently, we have a gas system that is very essential for sustainability for our hospitals, for our low-income customers, for our med rate customers, and so forth…"[43]

There are several other compelling reasons why attempts "to phase out all existing natural gas infrastructure would be ill advised..."[44] as presented by the Lawrence Livermore National Laboratory. These include the following:[45]

1. Existing natural gas distribution infrastructure could provide a platform to broaden the use of carbon-neutral or carbon-negative renewable gas and clean hydrogen. California should not preclude these options.
2. California has the largest renewable gas potential of any state, and reducing SLCPs is key.
3. Natural gas-fired electricity generation can be decarbonized through efficiencies.
4. Natural gas reduces the need for energy storage by allowing for flexible, dispatchable generation. The CAISO warns that there will be electricity capacity shortfall in 2022 and advocates that the CPUC ensure there are natural gas resources available to ensure reliability.[46]
5. Existing natural gas infrastructure, coupled with a renewable gas supply, can help decarbonize hard-to-electrify sectors, such as industry and transportation.
6. California already has the largest number of natural gas refueling stations in the nation and this number is expected to grow.

5. Methane Emissions from Natural Gas System are Overstated by CEC

The CEC staff presentation by Guido Franco discusses methane emissions from the natural gas value chain that overstate sector emissions. Mr. Franco bases his assessment on the

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[42] Energy Futures Initiative. *Optionality, Flexibility, & Innovation*. *Pathways for Deep Decarbonization in California.* Summary for Policy Makers. 2019. P. xiii. Available at: https://energyfuturesinitiative.org/

[43] CPUC Commissioner Shiroma at September 12, 2019, CPUC Commission Meeting. Available at minute 2:20 at: http://www.adminmonitor.com/ca/cpuc/voting_meeting/20190912/

[44] Lawrence Livermore National Laboratory (LLNL). Comments in response to the CEC's Workshop on The Natural Gas Infrastructure and Decarbonization Targets. P.2. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=228811&DocumentContentId=60143

[45] *Ibid.* Information summarized from LLNL.

[46] CPUC Rulemaking 16-02-007. Comments of the California Independent System Operator Corporation. July 22, 2019. Available at: http://www.caiso.com/Documents/Jul22-2019-Comments-PotentialReliabilityIssues-R16-02-007.pdf

Environmental Defense Fund (EDF) studies for emissions from production to the meter and a limited number of studies looking at after-meter emissions from different sectors. Several of these studies are still in progress. So, we will limit our comments to two of the studies that have been completed: EDF's study titled, *Assessment of methane emissions from the U.S. oil and gas supply chain*[47] and the Jet Propulsion Laboratory (JPL) study titled, *Atmospheric Methane Emissions Correlate With Natural Gas Consumption From Residential and Commercial Sectors in Los Angeles.*[48]

The EDF study suggests methane emissions are 60% higher than the estimate by U.S. EPA. The largest source of methane emissions in the value chain reported by EDF is from the production of natural gas. However, a recent National Ocean and Atmospheric Administration paper, *Long-Term Measurements Show Little Evidence for Large Increases in Total US Methane Emissions Over the Past Decade* finds:

> In the past decade, natural gas production in the United States has increased by ~46%. Methane emissions associated with oil and natural gas productions have raised concerns since methane is a potent greenhouse gas with the second largest influence on global warming. Recent studies show conflicting results regarding whether methane emissions from oil and gas operations have been increased in the United States. Based on long-term and well-calibrated measurements, we find that (i) there is no large increase of total methane emissions in the United States in the past decade; (ii) there is a modest increase in oil and gas methane emissions, but this increase is much lower than some previous studies suggest; and (iii) the assumption of a time-constant relationship between methane and ethane emissions has resulted in major overestimation of an oil and gas emissions trend in some previous studies.[49]

In fact, when we look at methane emissions over a longer period of time, US. EPA data illustrates that methane emissions from the natural gas sector show a significant decline over the past 20 years. Anassessment by the Gas Technology Institute (GTI) of the U.S. EPA inventory shows the methane emissions intensity currently is 40% lower than 1990 levels, dropping from 2.2% of consumption in 1990 to 1.3% in 2017.

The JPL study cited by Mr. Franco was released last month and SoCalGas asked GTI to review it. Attached is an assessment by GTI that raises significant questions about the conclusions drawn by JPL (see Attachment D). Importantly, GTI compared the JPL study to a study of measured appliance leakage and to other studies and data on seasonal trends in atmospheric methane emissions. GTI's assessment finds:

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[47] Alvarez, et al. *Assessment of methane emissions from the U.S. oil and gas supply chain*. 13 July 2018. Available at: https://science.sciencemag.org/content/361/6398/186

[48] He, et al. *Atmospheric Methane Emissions Correlate With Natural Gas Consumption From Residential and Commercial Sectors in Los Angeles*. 15 July 2019. Available at: https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2019GL083400

[49] Lan et al. Long-Term Measurements Show Little Evidence for Large Increases in Total U.S. Methane Emissions Over the Past Decade. April 25, 2019. Available at: https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2018GL081731

1. It is improbable that operation of natural gas space heating is a primary or even secondary contributor to this level of methane emissions.
2. The JPL paper also does not include an important mechanism that is a key contributor to seasonal changes in atmospheric methane concentrations – the process of methane oxidation.

As described in the GTI assessment, methane oxidation leads to a summer drop in atmospheric methane concentrations independent of methane emissions sources; even in locations far from natural gas production and consumption show a summer decline and winter increase in atmospheric methane concentrations.

SoCalGas recognizes the importance of reducing methane leakage from the natural gas sector. We have continuing research and programs to reduce methane leakage from our system. It is unfortunate that the CEC presented such a limited view on methane emissions with a bias to inflate the emissions from the natural gas system. Furthermore, the CEC's view of methane emissions from the natural gas sector is inconsistent with the state emissions inventory maintained by CARB. Greater care should be given by CEC staff in characterizing the current understanding of methane emissions from the use of natural gas.

The joint agencies should include brown carbon and sulfur hexafluoride (SF6) in their analysis if they are to include upstream methane emissions as they examine building electrification. At the CEC's workshop on The Natural Gas Distribution Infrastructure and Decarbonization Targets held on June 6, 2019, AdTra offered an analysis on how electric grid-caused fires create brown carbon emissions that should be considered when developing policies on transportation and building electrification. AdTra concludes that, "[fire-caused attributable indirect] GHG emissions need to be duly considered. Based on our analysis, it is our view that any credible assessment of policy actions and measures to decarbonize California's economy cannot ignore fire-caused attributable indirect GHG emissions."[50]

Additionally, electrification has risks of adding significant amounts of super high global warming potential gases (thousands of times more potential than CO_2) to the atmosphere from refrigerants and SF6. A recent study shows the amount of SF6 has risen rapidly in the atmosphere from the added electrical infrastructure from renewables.[51] The 2018 IEPR Update briefly acknowledged the risk of adding heat pumps with super high global warming potential gases. However, the concern was quickly dismissed by explaining that new lower global warming refrigerants are being developed and will likely be on the market soon. Ironically, SoCalGas is currently demonstrating a highly efficient gas heat pump for a restaurant that eliminates the refrigerant, but this technology would not be considered in the current proposed program due to the bias towards electrification-only technologies.

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[50] AdTra Comments. Docket 19-MISC-03. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=228838&DocumentContentId=60175

[51] Widger, Phillip and Haddad, Abderrahmane. Evaluation of SF_6 Leakage from Gas Insulated Equipment on Electricity Networks in Great Britain. August 6, 2018. Available at: https://www.mdpi.com/1996-1073/11/8/2037

6. Correction of Claims Regarding Natural Gas Use and Air Quality in Homes

During the workshop, Guido Franco presented "CEC Research on GHG impacts of Natural Gas System." He made a blanket statement that "burning of natural gas in our homes can result in poor indoor air quality." This is an over simplification of the factors affecting health and air quality. In fact, the latest study shows that with proper ventilation indoor air quality is not impacted by the use of natural gas appliances and has decreased overall since 2008.[52] Mr. Franco appears to have based his conclusion on two studies – Logue, et al and Garcia, et al. However, he did not give the full context for these studies. The Garcia study concluded decreases in ambient NO_2 and PM2.5 were associated with lower asthma incidence: it did not examine indoor air quality. The transportation sector accounts for over 90% of the ambient NOx inventory in Southern California.

Regarding the Logue study, Mr. Franco "estimated that 62% of the population using natural gas for cooking is exposed to NO_2 levels that exceed acute health-based standards and guidelines." The percentage cited is the model simulation result without coincident venting. The study further states "[s]imulation results suggest that regular use of even moderately effective venting range hoods would dramatically reduce the percentage of homes in which concentrations exceed health-based standards." This result is consistent with previous studies conducted by CEC and CARB.

CARB has found the emissions from the food being cooked, and not from burner or heat source operations, that represent the chief source of concern with respect to indoor air quality.[53] The agency states that exposure to pollutants from natural gas can result from three general scenarios:

- Improper or ineffective venting of exhaust gases from appliances required to be vented;
- Using cooking burners without venting or with ineffective venting; and
- Using illegal vent-free heaters or fireplaces.[54]

In addition, according to CARB, "[t]he act of cooking itself, whether with gas or electric stovetop burners or ovens, can also generate elevated levels of most of these pollutants, due to heating oil, fat, and other food ingredients, especially at high temperatures … and [s]tudies have revealed that home air pollutant levels can exceed health-based standards when people are cooking in kitchens with poor ventilation."[55]

There are many factors that impact indoor air quality and asthma. The joint agencies should not cherry pick studies to support an electrification-only approach. The joint agencies should continue to support research that accurately assesses all causes of poor indoor air quality.

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[52] Chan et al. Ventilation and Indoor Air Quality in New California Homes with Gas Appliances and Mechanical Ventilation. 2019. Available at: https://eta.lbl.gov/publications/ventilation-indoor-air-quality-new

[53] California Air Resources Board. January 2006. Residential Cook Exposure Study Final Report. Retrieved from https://www.arb.ca.gov/research/indoor/cooking/cooking.htm

[54] *Ibid.*

[55] California Air Resources Board Website. "Cooking and Range Hoods." Available at: https://www.arb.ca.gov/research/indoor/cooking/cooking_range_hoods.htm

7. Building Decarbonization Strategies Must Prioritize Energy Efficiency

The Draft EE Action Plan's focus on improving decarbonization must ensure that value is placed on energy efficiency efforts. California has led the nation in energy efficiency programs since the 1970s. In the last five years, SoCalGas' Energy Efficiency Programs have saved more than 180 million therms (enough natural gas usage for 403,000 households a year) and reduced GHG emissions by nearly one million metric tons (the equivalent of removing more than 202,000 cars from the road.) Increasing energy efficiency is one of the fastest, most cost-effective and cleanest solutions to lower GHG emissions.

As stated earlier, switching from a dual-fuel to an all-electric home is not going to drive down electric demand nor be a guarantee of GHG emissions reduction due to the uncertainty around the cost and increased penetration of renewables in the grid, the use of super high global warming gases in electric equipment (e.g. refrigerants, SF6), the adoption rates or acceptance of all-electric homes by consumers, and the need for resilience and reliability of the energy system as a whole. This will present new electric reliability challenges for CAISO. Energy efficiency must remain paramount to minimize peak load.

In the residential sector, energy efficiency plays a vital role in ensuring the reduction of GHG emissions as it can account for as much as 550 million metric tons of CO_2 equivalent emissions reductions annually by 2050. The Final EE Action Plan should ensure cost effective energy efficiency efforts are placed at the forefront of any decarbonization efforts, consistent with the loading order for preferred resources adopted in 2003.

Conclusion

SoCalGas provides these comments to help move California towards meeting our aggressive climate goals in a thoughtful, reasoned, studied, and cost-effective way that also accounts for customer affordability and choice. The joint agencies should support policies that advance decarbonizing the gas delivery system, and not just the electric delivery system, by supporting policies to increase the use of a portfolio of options including renewable gas, hydrogen, and power-to-gas technology. We believe a balanced and diversified approach to decarbonizing buildings should be pursued.

Additionally, we ask the joint agencies to convene a broader array of experts to better inform this year's IEPR proceeding so California can look more objectively at all opportunities available to reduce GHG emissions from buildings.

Sincerely,

/s/ Tim Carmichael

Tim Carmichael
Agency Relations Manager
Southern California Gas Company

SoCalGas Comments in Response to the IEPR Joint Agency Workshop on Energy Efficiency and Building Decarbonization & *2019 California Energy Efficiency Action Plan Draft Staff Report*, Docket #19-IEPR-06

Attachment A:

OPENING COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON ORDER INSTITUTING RULEMAKING REGARDING BUILDING DECARBONIZATION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19.01.011 (Filed on January 31, 2019)

OPENING COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON ORDER INSTITUTING RULEMAKING REGARDING BUILDING DECARBONIZATION

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March 11, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed on January 31, 2019)

OPENING COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON ORDER INSTITUTING RULEMAKING REGARDING BUILDING DECARBONIZATION

Pursuant to the Order Instituting Rulemaking Regarding Building Decarbonization filed by the California Public Utilities Commission (Commission), Southern California Gas Company (SoCalGas) hereby submits its opening comments on the Order Instituting Rulemaking (OIR).

I. INTRODUCTION AND GENERAL DISCUSSION

SoCalGas appreciates the opportunity to participate in this proceeding which will explore options to promote and bolster the State's efforts to curb greenhouse gas (GHG) emissions. SoCalGas supports such efforts and has long been a leader in developing emerging technology and energy efficiency (EE) programs that deliver meaningful GHG emissions reductions. We are proud of the advances we have made through our programs and partnerships with equipment manufacturers and our customers, and we recognize the multifaceted challenges presented in achieving mandated GHG emissions reduction targets by 2030 and achieving carbon neutrality by 2045.

Californians currently rely on a diverse energy system that is reliable, resilient, and strives to remain affordable while maintaining consumer choice. In this OIR, we look forward to working with the Commission as it looks at how to address the State's climate goals while maintaining reliability, resiliency, affordability, and consumer choice. This will require thinking more broadly about renewable energy and supporting an integrated and holistic approach to reducing GHG emissions in the building sector. Fixating on a one-track solution, such as electrifying end uses, can lead to missing real solutions to address climate change. We should support an inclusive energy strategy that objectively considers all options and encourages and allows for current and future innovation. We should not simply assume that all energy solutions to achieve carbon neutrality are known to us today.

The options implemented should not cause significant uncertainty and burden for workers, their families, and the millions of residents and businesses that depend on a reliable and affordable energy supply for their homes and businesses. The solutions should be approachable (in both cost and use) so as to encourage acceptance and adoption by consumers.[1] Any energy solution must factor in choice and affordability, so people can continue to work and live in California, and businesses can remain here.[2]

In order to have any meaningful impact on global GHG emissions, California's energy solutions must demonstrate results that can be adopted by other states and countries.[3] California emits less than 1% of global GHG emissions; thus, reducing California's GHG emissions alone will not be enough.[4] As we address ways to advance carbon neutrality, it will be important to consider solutions that can be adopted by others in the United States and around the world.[5]

With this in mind, and that the "initial scope of this proceeding is designed to be inclusive of *any* alternatives that could lead to the reduction of [GHG] emissions associated with

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[1] Rapid consumer adoption will be key to the success of any policy. We have learned from the transportation sector (zero-emissions vehicles) that the more we depend on consumer behavior change, the more the targets are at risk.

[2] The Los Angeles area is the largest manufacturing region in the United States, and California has the fifth largest economy in the world.

[3] California has set aggressive targets, spurring technology development, and set new standards for buildings. Many, if not most, of the steps we take in the energy and environmental arena ripple benefits across the country and beyond. However, there are many uniquely Californian characteristics that can make replicating California policy challenging for other states and regions. For example, Californians benefit from the availability of solar, while other regions have not adopted renewable portfolio standards due in part to the lack of available renewable resources. If other states and countries cannot generate the same level of renewables in the electric sector, then a push towards a siloed solution of electrifying buildings will not be an effective strategy to reduce GHGs in other regions.

[4] California Energy Commission using data from http://www.globalcarbonatlas.org (last updated December 2018).

[5] Similarly, we must absorb lessons from around the world. Germany spent more than $600 billion on green energy subsidies and infrastructure investments, but will likely miss its 2020 target of reducing GHG emissions by 40% over 1990 levels due to its rush to convert its electricity supply to renewable resources without adequate planning, resulting in the need to turn to coal-fired plants to provide reliability. In 2017, more than one-third of Germany's energy supply came from coal. Germany: Nikolewski, Rob, "Is California going the way of Germany when it comes to energy?" The San Diego Union-Tribune, November 11, 2018.

energy use in buildings,"[6] we propose that the Commission thoughtfully consider all options that will contribute to achieving the State's climate goals, including renewable gas (RG). RG, including biomethane, hydrogen, and methanated renewable hydrogen, can be used to remove carbon from other sectors of the economy[7] while reducing GHG emissions from the building sector.[8] It also allows the existing natural gas infrastructure to be utilized.[9] As an additional benefit, consumers do not have to bear the costs of replacing appliances, retrofitting homes, etc.

Utilizing RG supports energy reliability and resiliency while keeping consumer costs down,[10] and moreover enables consumer choice—which cannot be undervalued. About 90% of residential energy consumers in Southern California use natural gas for space and water heating.[11] Our customers expressly prefer a choice in how they heat their homes and cook their food.[12] When the Commission issued a proposal to direct SoCalGas to implement a moratorium

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[6] OIR at 2 (emphasis added).

[7] While this proceeding pertains specifically to the building sector, we must still consider solutions that address all sectors. Residential and commercial buildings account for 7% and 5%, respectively, of GHG emissions in California. The transportation sector accounts for 41%; the industrial sector accounts for 23%; the electricity sector accounts for 16%; and the agriculture sector accounts for 8%.

[8] RG helps us reduce fugitive emissions by harnessing our waste streams, effectively converting emissions into fuel. The largest source of methane emissions in California (more than 80%) is agriculture, dairies, landfills, and waste water. We can capture this waste; convert it into biogas using anaerobic digestion; process the biogas to make it pipeline ready; inject it into existing pipelines; and use the fuel where natural gas is used. RG can also be made from the woody biomass that is removed from forests to reduce the risk of catastrophic wildfires.

[9] Because the underground infrastructure is resilient to wildfires and other extreme climate and weather events, such as wind storms, microgrids supported by RG could be deployed in high-risk areas.

[10] As a rule of thumb, $3.00 per MMBtu, close to generally prevailing natural gas commodity prices, is equivalent to about $0.01 per kWh. Therefore, forcing customers to switch to electric end-uses could increase their energy costs several times over.

[11] California Energy Commission (CEC, "2009 California Residential Appliance Saturation Study: Executive Summary," Table ES-3: Natural Gas UEC and Appliance Saturation Summaries by Utility, October 2010.

[12] California Reports Show Homeowners Prefer NatGas Over Electrification. Available at: https://www.naturalgasintel.com/articles/114152-california-reports-show-homeowners-prefer-natgas-over-electrification

on new commercial and industrial natural gas connections in Los Angeles County,[13] parties[14, 15] vociferously opposed the Commission's proposal and underscored the harm that would be done to the economy if the moratorium were implemented.

Removing natural gas from homes would impose a significant burden on consumers in terms of cost, choice, and convenience, and could result in serious unintended consequences, including driving opposition to any climate change goals related to buildings; this is unnecessary because the same environmental benefits can be achieved without imposing those burdens on customers. Increasing use of RG to displace traditional natural gas can support the maintenance of a safe and reliable energy system, promote a robust California economy, and make significant progress towards California's climate and air quality goals.[16] With this in mind, SoCalGas just recently announced its commitment, regulatory authority permitting, to displace 5% of traditional natural gas in its pipelines with RG by 2022 and 20% by 2030. SoCalGas also recently filed a request with the Commission to allow customers to purchase renewable natural gas for their homes and businesses. Replacing less than 20% of traditional natural gas with renewable natural gas achieves the same emissions reductions as overhauling *all* of California's buildings to be electric-only, *at a significantly lower cost*. This is one part of the solution to attain the State's climate goals, and we look forward to exploring others in this proceeding.

II. SPECIFIC QUESTIONS FROM THE SCOPING RULING

1) Do you agree or disagree with the organization of the proceeding into the four proposed categories (Implementing SB 1477, Potential Pilot Programs for Decarbonization of New Construction in Areas Damaged by Wildfires, Coordinating with

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[13] CPUC Draft Resolution G-3536, Emergency Order Direction Southern California Gas Company to Implement a Moratorium on New Natural Gas Service Connections. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K367/201367863.PDF

[14] Los Angeles County, American Gas Association, LA County Business Community Coalition, Bloom Energy, California Manufacturers and Technology Association, Biz Fed LA County, PTG Water & Energy, Californians for Affordable and Reliable Energy, California Council for Environmental and Economic Balance, Clean Energy, and Honeybird Restaurant

[15] Los Angeles Business Journal. January 5, 2018. *Business Opposition Mounts to Proposed Moratorium on New Natural Gas Hookups*. Available at: http://labusinessjournal.com/news/2018/jan/05/business-opposition-mounts-proposed-moratorium-new/

[16] To this end, SoCalGas recently filed its "Green Tariff" Application, A.19-02-015, seeking authority to allow customers the option to purchase RG. The voluntary program would provide customers with carbon neutrality options and helps the environment by repurposing methane from waste that otherwise would vent to atmosphere, and its implementation costs would be paid for by customers who choose to enroll in it.

Title 24 Building Standards and Title 20 Appliance Standards, and Building Decarbonization Policy Development)? Explain your reasoning.

SoCalGas agrees with organizing the proceeding into the four proposed categories. In order to best inform the discussions, and to allow sufficient time for the many considerations that are implicated in this proceeding as well as allow robust public participation, we further recommend that the Commission split the OIR into two distinct phases: the first phase should focus on implementing the statutory requirements of Senate Bill (SB) 1477, and the second phase should focus on the remaining three categories while prioritizing building decarbonization policy. By prioritizing building decarbonization policy, the Commission can establish an informed opinion that will help drive the process of rebuilding areas that were damaged by wildfires according to Title 20 and 24 building standards. Additionally, the findings and determinations made regarding building decarbonization policy will likely have broader implications on the overall resiliency and reliability of California's energy infrastructure, the economy, the cost of home ownership, and utility rates. As such, the building decarbonization policy development should not be rushed and will benefit from allowing time to obtain significant input from stakeholders as both the public and private sectors likely will be impacted by the policies that are adopted.

SoCalGas asks the Commission to invest the appropriate time and resources to conduct scientific and fact-based studies along with thorough cost analyses when developing building carbon neutrality policies and recommends this category not be fast-tracked as the impacts will be felt by all Californians. It is imperative that there is sufficient time to conduct studies and develop a robust record to inform policy development in this proceeding.

2) How should the Commission go about determining the administrative structure for the SB 1477 BUILD and TECH programs, from among the options listed in the statute?

The Commission should leverage the current structure it has in place for most of its ratepayer-funded demand-side management programs (e.g., energy efficiency, demand response, solar thermal, etc.) to allow the local investor owned utilities (IOUs) to administer the Building Initiative for Low Emissions Development (BUILD) and Technology and Equipment for Clean Heating (TECH) programs. This approach has served ratepayers, the Commission, and California well, as programs utilizing it have generally achieved established goals in a cost-effective manner within budget.[17] The Commission has actively pushed integration across demand-side management (DSM) programs, whether through an integrated DSM (IDSM) approach or through an integrated distributed energy resources (IDER) approach. In both cases, the local utility is the cornerstone of the administrative model given the need to coordinate with system planning and operations. Many of the technologies likely to be adopted for the BUILD and TECH programs are those that qualify for existing energy efficiency, solar thermal, and demand response programs. It thus will be critical to integrate the BUILD and TECH programs into the existing programs to provide a comprehensive IDSM or IDER approach. SoCalGas serves as a resource aggregator on behalf of our customers. The American Council for an Energy-Efficient Economy (ACEEE) recently recognized SoCalGas' integrated partnership model with the Los Angeles Department of Water and Power (LADWP) whereby programs are joined in a single package to provide gas, electric, and water incentives to offer comprehensive efficiency solutions to customers in a seamless and integrated manner.[18] SoCalGas has similar partnerships with other local electric utilities, water utilities, governmental agencies, and air quality districts throughout our service territory. This model has been highly successful for all participating utilities and, more importantly, a benefit for customers.

These and similar existing relationships can be utilized by SoCalGas and the other utilities to assure that their respective portions of the $50 million in annual SB 1477 funding are leveraged with existing programs and resource platforms designed to increase customer participation, the comprehensiveness of that participation, and the overall success of the program in order to provide meaningful energy efficiency and emission-reduction benefits for customers.

3) If the Commission chooses a third-party administrator, what process should it use to select the administrator?

For the reasons stated in response to Question 2, a third-party administrator is not the best option to administer the BUILD and TECH programs. Familiarity with their own systems,

[17] See, e.g., Energy Efficiency Portfolio Report, California Public Utilities Commission, March 2018, available at: http://www.cpuc.ca.gov/uploadedfiles/cpucwebsite/content/about_us/organization/divisions/office_of_governmental_affairs/legislation/2018/13-15%20energy%20efficiency%20report_final.pdf

[18] *See* The New Leaders of the Pack: ACEEE's Fourth National Review of Exemplary Energy Efficiency Programs, ACEEE, January 2019, at 112. Available at: https://aceee.org/sites/default/files/publications/researchreports/u1901.pdf

operations, and existing programs will allow IOUs to attain synergies that will lead to efficiencies that a third-party administrator cannot realize.

Nevertheless, if the Commission determines that a third-party administrator is best suited to these tasks, then a third-party administrator(s) should be procured via a competitive solicitation process. The solicitation process should be governed by a group that consists of relevant stakeholders, namely the participating utilities and the CPUC's Energy Division. Additionally, there should be a series of workshops to allow those stakeholders to provide input to inform the solicitation process. If a third-party is selected to administer the program(s), then they must work closely with the utilities and their existing demand-side management programs in order for the programs to be integrated and most effective. The utilities should be a key partner in all steps to ensure that proposed goals are reasonable and rolled out efficiently. The utility staff will be composed of engineers and experts who will prepare analysis, review documentation and make assessments and recommendations as deemed necessary.

4) How should the Commission establish the budget for each program? What portion of the budget should be reserved for program evaluation? How should the program evaluator be selected?

Senate Bill 1477 prescribes a combined annual budget of $50 million across the participating California gas utilities. SoCalGas believes the BUILD program should be allocated a higher percentage of the budget than the TECH program because the BUILD program represents a better opportunity to drive benefits that likely will be realized sooner to accomplish the stated legislative goals. The BUILD program provides incentives to community and home builders throughout California, including those in disadvantaged communities. A larger investment in the BUILD program will allow these builders to receive incentives quickly to build more efficient homes that have a lower carbon footprint. The BUILD program also aligns more closely with the Commission's ratepayer-funded and utility-administered energy efficiency programs, which can thus be leveraged and integrated in order to further maximize program goals.

Unlike the BUILD program, which provides quick and direct incentives to those who will actually build more energy-efficient homes, the TECH program focuses on education and training. Based on SoCalGas' experience, the impact and effectiveness of programs with similar parameters have proven to be difficult to measure. Moreover, the TECH program seems less likely than the BUILD program to have a quick impact on achieving California's aggressive energy goals in the near future. Based on the foregoing evaluations, SoCalGas proposes at least 75% of the annual budget be allocated to the BUILD program.

SoCalGas agrees that program evaluation is imperative to measure the impact and cost-effectiveness of the programs. Therefore, the Commission should set aside a portion of the budget towards this effort.[19] The program evaluation should be done by an independent consultant selected through a competitive solicitation process. Similar to the process outlined above for a third-party administrator, SoCalGas believes it will be important that a series of workshops be conducted to allow for stakeholder input to help inform the solicitation and selection process.

5) What program design parameters should be established by the Commission independent of the program administrator, and which aspects should it allow the selected program administrator to develop on behalf of the Commission?

For example:

a) Technology eligibility criteria

b) Process for evaluating new technologies

c) Guidelines and evaluation metrics

d) Criteria for scoring and selecting projects

As discussed above, the utilities are best positioned to administer the BUILD and TECH programs. Under that construct, the Commission should participate in program oversight and performance measurement as needed, as well as establish critical guidelines for program implementation. For example, the Commission should, as part of this proceeding, work with the utilities to establish the following parameters:

- Guidelines on eligible technology categories;
- Overarching program goals and objectives;
- Budget allocation between the BUILD and TECH programs;
- Budget allocation among the funding gas utilities;

[19] The Commission could refer to its ratepayer-funded energy efficiency programs as a guideline for determining the evaluation budget.

- Develop standardized metrics;
- Establish program evaluation criteria; and
- Conduct program evaluation.

For each of these above areas, the Commission should promote input from stakeholders, namely the participating utilities. Some of the criteria may be different across the two programs. For example, the BUILD program may not require a lot of involvement and oversight as it is an incentive program. Beyond the areas suggested above, the program design should largely be left to each utility administrator. Program design includes eligibility criteria, outreach plans, incentive rates, marketing efforts, and partner integration and program leveraging. The ability of each of these design criteria to be adaptive and flexible to local geographic, demographic, and economic conditions will be critical for success of the programs.

6) Should the Commission consider proposals for new rate designs as part of the design and implementation of the BUILD and TECH programs?

SoCalGas does not have sufficient information at this time to provide meaningful comments on this question. We appreciate the opportunity to comment on this in the future after additional information becomes available.

7) What goals should the Commission set for building decarbonization?

California's relevant energy goals are focused on technology-neutral emissions reductions intended to achieve climate stabilization. The long-term goal is total, economy-wide carbon neutrality by 2045.[20] The short-term goal, as established by Assembly Bill (AB) 3232 (2018), is a 40% reduction of GHGs from the building sector by 2030.

How these legislative goals can best be achieved will be explored and considered in depth in this proceeding. The options to consider are numerous and SoCalGas believes they must be vetted thoroughly before anything is determined. The following is a non-exhaustive list of the most important considerations in achieving the State's climate goals.

Goal #1 – **Maintain Energy Reliability.** The Commission should consider a multifaceted approach to lowering the carbon intensity of buildings in order to maintain energy

[20] Executive Order B-55-18 To Achieve Carbon Neutrality, available at: https://www.gov.ca.gov/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

reliability in our State. In order to best do this, the Commission should not mandate or incentivize one technology or fuel source over others, but rather objectively consider all options and ultimately utilize a combination thereof. This is reflected in the Commission's guiding principle for Building Decarbonization Policy Development that it should "avoid picking technology winners and encourage competition among technologies, vendors, and approaches."[21] We must explore all viable options and foster policies that will encourage the development of innovative technologies and new ideas in order to achieve long-term compliance with State goals.[22] We should not assume that all energy solutions to achieve carbon neutrality are known and in existence today. The Commission should consider carbon neutrality options from a holistic (i.e., cross-sector) and integrated energy system perspective. The solution to addressing climate change is going to be multifaceted because many sectors of the economy are interconnected. California produces about 1% of the world's GHGs and should contribute to meaningful climate solutions by creating ideas that are scalable and exportable on a global basis. For example, RG has synergistic GHG reductions in the building, industrial, agriculture, transportation and electric generation sectors. The synergy is accomplished two ways: 1) by capturing methane emissions from biogenic sources that would normally vent to atmosphere and injecting them into the gas grid for all end-uses, displacing traditional natural gas, and 2) taking excess renewable electricity and producing hydrogen[23] via electrolysis ("Power-to-Gas"[24]) that

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[21] See *Order Instituting Rulemaking Regarding Building Decarbonization* issued on January 31, 2019 at 16.

[22] The Commission's interest in exploring pilot programs represents an important opportunity to collaborate on the advancement of a variety of new technologies. SoCalGas has had programs and partnerships such as Research, Development & Demonstration (RD&D) projects in collaboration with the California Energy Commission, Department of Energy, Southern California Air Quality Management District, natural laboratories, start-up companies, and customers. These efforts have resulted in advances in the areas of low-NOx engines, natural gas vehicles, waste-to-energy, energy storage, and distributed renewable hydrogen generation. This experience renders us well-equipped to meet the challenges of achieving the State's carbon neutrality goals.

[23] Hydrogen is a zero-emission fuel that can reduce emissions in the transportation sector. Some percentage of hydrogen can be injected into the natural gas stream to decarbonize it. Hydrogen's significance as an energy storage technique is growing globally. The United Kingdom currently is experimenting with allowing up to 20% green hydrogen to be injected into its gas network. The University of California system, which plans to be carbon neutral by 2025, has announced that renewable natural gas and hydrogen will play a significant role in achieving their goal.

[24] Today we dump excess electricity or pay other states like Arizona to take it from us. Batteries can store some excess energy but do not help with long-term storage needs. Power-to-Gas involves combining excess renewable electricity with a small amount of water and running it through electrolysis, which

can be stored, injected into the natural gas grid, used in a fuel cell[25] or a fuel cell electric vehicle, or converted to methane for end uses, thereby also displacing traditional natural gas. This concept creates flexibility in the energy system and is an extremely adaptive method to address climate risks.

RG created from capturing agricultural manure and waste, wastewater treatment plants, landfills and diverted organic waste facilities exists extensively in Europe and is growing here in the United States. Dairy, food, and green waste is considered a carbon-neutral, and in some cases carbon-negative, energy source by the California Air Resources Board (CARB). By developing and incentivizing at scale, the production of RG will support cost reductions from economies of scale, bring down the cost of the fuel, and create jobs in California.

Goal #2 – <u>Affordable Solutions.</u> The affordability impacts of carbon neutrality in the building sector should be considered in a broad context. For example, how will building decarbonization affect homeownership and homelessness, including Governor Newsom's goal of addressing affordable housing?[26] If electrification of all energy end uses, such as space and water heating, is pursued, how much new electric generation, transmission and distribution infrastructure will be required to realize the goal, and what will the ongoing maintenance, safety, and environmental costs be for new electric infrastructure? The cost impacts of the different technologies and fuels will be different, and all must be considered relative to each other. At the least, the Commission should look at the energy bill impacts from different fuel options; the difference in cost between in-state RG versus out-of-state RG; and upfront installation and

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converts electrical energy into chemical energy and splits the molecules into pure hydrogen and oxygen. The oxygen can be used in other applications, and the hydrogen case can be used as a fuel or stored in existing pipelines. Or, hydrogen can be combined with carbon dioxide and run through methanation to create renewable methane. UC Irvine is using Power-to-Gas to increase its renewable energy use from 3.5% to 35%. University of California Irvine (UCI) and SoCalGas research presented at UCI's International Colloquium on Environmentally Preferred Advanced Generation (ICEPAG) on March 30, 2017.

[25] Unlike batteries, fuel cells do not merely store energy; they also generate it. When hydrogen-rich fuel such as clean natural gas or renewable biogas enter the fuel stack in a fuel cell, they react electrochemically with oxygen (i.e., ambient air) to produce electric current, heat, and water. While a typical battery has a fixed supply of energy, fuel cells continue to generate electricity as long as fuel is supplied.

[26] OIR at 11. The Commission should take into consideration the impact of the policies determined in this proceeding on Governor Newsom's goals of addressing affordable housing. Building decarbonization comes with costs, and there may be unintended consequences, e.g., low income and disadvantaged communities may have additional expenses that they can ill afford thrust upon them.

replacement costs of new equipment, appliances, controls, and/or associated appurtenances associated with the building and utility. For example, residential batteries may have a 10-year life and thus would need to be replaced 5-10 times over the life of a home; this should be accorded due weight. The Commission should make every effort to reduce the cost impacts of new policies on homeowners, businesses, and other ratepayers. The Commission, with the help of stakeholder input, should also consider the implications of carbon reduction strategies on affordability of energy to the most vulnerable customers, who require the most safeguarding.

Goal #3 – Consumer Choice and Adoptability. The impacts of implementing new building carbon neutrality policies on California residents may be significant. If the goals are to be met, consumer choice must be an option. It should not be assumed that customers will accept potentially drastic changes to their current energy choice(s) or end-use equipment. Appropriate thought must be given to minimizing costly and jarring transitions while still making progress towards the State's climate goals. Additionally, the Commission should consider the speed of adoptability of any option, especially where physical changes are required, from the sheer logistics of dealing with millions of buildings.

Goal #4 – Resiliency: Not Relying on A Single Source of Energy. Currently, dual-fuel homes provide their occupants with options which become especially important when there are electricity outages. You can still cook, have hot water or even have backup power from a natural gas fueled generator. Research[27] released by the California Energy Commission (CEC) in 2018 found that gas assets and service disruptions are far less vulnerable than electric infrastructure to widespread service disruptions caused by wildfires, extreme heat, sea-level rise, flooding, and other extreme climate-driven events. Additionally, SoCalGas commissioned a consulting firm, ICF, to investigate and document the lessons learned from the impacts of various natural disasters throughout the country on utility and transportation infrastructure.[28] The case studies highlighted concerns with an over-reliance on any single energy source and demonstrated that utilizing a diverse energy delivery system contributes to greater reliability and community

[27] CEC. Regional Workshops held on January 24, 2019. Potential Impacts and Adaptation Options for Electricity and Natural Gas Systems from Climate Vulnerability in San Diego Area. Slide deck available at: http://www.climateassessment.ca.gov/events/docs/20190124-Slides_ICF.pdf

[28] SoCalGas Study Offers Lessons in Resiliency Planning to Help Communities and Utilities Prepare for Disasters. Available at: https://www.sempra.com/newsroom/press-releases/socalgas-study-offers-lessons-resiliency-planning-help-communities-and

resilience and enhances public safety. The case studies also found that natural gas infrastructure and services were relatively resilient to recent hurricanes and wildfires. Both the CEC and ICF studies stress the need for the State to pursue balanced energy policies that are inclusive of a diverse energy portfolio that include multiple fuels and technologies.

For sensitive customers, such as those residents and businesses in high-risk fire areas, it may be prudent to develop microgrid solutions that rely on RG to keep power on during intentional outages. Commercial buildings that need reliable energy for critical equipment (e.g., hospitals) may choose to invest in highly efficient combined heat and power systems that are independent of the electric grid to support their needs. Allowing for such flexibility should be considered.

Goal #5 – Optimize All Carbon Neutral and Carbon Negative Options, Including RG. If the intent is to make significant strides to combat climate change while continuing to prioritize reliability and resiliency of the energy grid, affordability, and consumer choice, the Commission should pursue strategies that incorporate carbon neutral and carbon negative options, including RG.[29] Doing so will accelerate accomplishment of the State's carbon neutrality goals,[30] provide a diversified mix of fuel resources available to accomplish these goals, maintain lower costs for customers, and allow for consumer choice.

With this in mind, just recently SoCalGas announced its commitment, regulatory authority permitting, to displace 5% of traditional natural gas in its pipelines with RG by 2022 and 20% by 2030. SoCalGas also recently filed a request with the Commission to allow customers to purchase renewable natural gas for their homes and businesses. The hope is that these activities will accelerate the development of in-state renewable gas projects and achieve significant emissions reductions. Replacing less than 20% of natural gas with renewable natural gas achieves the same emissions reductions as overhauling *all* of California's buildings to be electric-only, *at a significantly lower cost*. This solution avoids a mandate to change out millions of appliances and spend money to replace existing infrastructure.

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[29] For example, the use of RG from captured methane from dairies, food and green waste is considered carbon negative.

[30] In addition, there are emerging technologies that can either remove carbon from natural gas prior to use (methane pyrolysis) or capture and use the carbon dioxide (CO2) typically produced when natural gas is used. CO2 can be used to form $C_1 – C_x$ hydrocarbons that are used in a variety of structural materials. When carbon capture and utilization technologies are applied to RG resources, carbon-negative cycles can be created.

Energy leaders in other parts of the world, particularly in Europe and Canada, are also looking at RG as a means to make the gas supply carbon neutral. France has adopted a renewable gas standard that calls for RG to make up at least 30% of natural gas consumption by 2030. Énergir, a Canadian natural gas utility, is working towards efforts to have a fully developed RG marketplace by 2020 and has a target to distribute 5% RG by 2025. In 2018, SoCalGas announced a collaboration with several utilities in Europe and Canada to advance the development of policies and technologies to support making natural gas supplies carbon neutral. "The development of [RG] is a real challenge for the energy transition and has a key role to play in the context of the low carbon strategy. The signing of this partnership agreement at the World Gas Conference reflects our shared desire to develop green gas and associated technologies and facilitate its production and injection into natural gas networks," said Christophe Wagner, International Director for French utility GRDF.[31]

Internationally, the United Nations Climate Change Council and the World Green Building Council have set goals for buildings to achieve net zero emissions by 2050.[32,33] In Europe, in order to attain this goal, countries are looking at both renewable electricity and RG to deliver the energy needs of the building sector. California also should consider RG as an option to help achieve the State's climate goals, especially given extensive RG delivery capability and the very high market penetration of natural gas use in residential buildings. As we transition to low-carbon energy, gas and electric systems should work in harmony to provide reliability and resiliency affordably. RG is an essential part of the solution.

8) What other specific initiatives should the Commission examine to further the goals outlined in the question above?

Some items for the Commission to consider that would advance building carbon neutrality goals include:

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[31] Press release by SoCalGas, Energir, GRDF and GRTgaz. Available at: https://www.prnewswire.com/news-releases/socalgas-energir-grdf-and-grtgaz-announce-collaboration-on- low-carbon-and-renewable-gas-initiatives-during-world-gas-conference-300674664.html

[32] Twitter. UN Climate Change. Available at https://twitter.com/UNFCCC/status/1004664904719224833

[33] World Green Building Council. June 2018. *World Green Building Council Calls on Companies Across the World to Make their Buildings Net Zero Carbon.* Retrieved from http://www.worldgbc.org/news-media/world-green-building-council-calls-companies-across-world-make-their-buildings-net-zero.

- Broad public engagement on critical policy changes that are likely to result in significant impacts;
- An integrated and holistic solution that leverages existing utility infrastructure;
- Resiliency of energy grid, reliance on multiple versus single technologies, including, e.g., distributed self-generation using high efficiency fuel cells;
- Cost of implementing policy – including impacts to homeowners/renters, low-income communities, businesses, and utility rates; and
- Economic implications of a statewide policy on different regions - how building carbon neutrality policies impact different regions in California, like San Francisco versus the San Joaquin Valley, and considering implications to low-income communities and the growing senior population.

Regarding the Commission's interest in exploring pilot programs to help make carbon neutral homes in areas impacted by wildfires, SoCalGas supports this effort. Wildfires are not a one-time occurrence, nor are wildfires the only type of disaster that could impact buildings. For this reason, SoCalGas suggests that the Commission's policies should be broad enough to help address carbon neutrality in areas impacted by any catastrophic event. Further, SoCalGas recommends that education and consumer protection be a primary goal. As noted in Decision Adopting Net Metering Consumer Protection Measures Including Solar Information Packet, D.18-09-044, it is important to ensure that residential customers receive accurate information to make informed decisions about their energy options. Particularly, consumers must be protected against aggressive and unscrupulous sales tactics.[34] For these reasons, SoCalGas believes that a Decarbonization Information Packet, similar to that used in the Net Energy Metering proceeding,[35] should be developed by stakeholders and approved by the Commission for distribution.

SoCalGas suggests that an approved information package should be agnostic regarding technology and fuel. At minimum, it should list all available energy options, associated costs, and corresponding estimated GHG reductions. Educating consumers about their energy options so they can make the choices that best suit their needs is important. For example, per Resolution

[34] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M230/K892/230892616.PDF
[35] D.18-09-044 at Appendix A.

ESRB-8, electric utilities may proactively shut down power to limit the impact or damage of power lines to communities when the utilities are aware of dangerous conditions.[36] As a result, communities may be left without power for an undetermined amount of time. Because consumers will be affected differently, and because consumers best know their energy needs, they should be made aware of their options,[37] including the existence of clean gas technologies capable of reducing GHGs, such as low-emission space and water heater equipment.

Estimated costs should not only focus on the initial cost of the GHG-reducing technology or project. In accordance with SB 1477 § 1, projects are to receive incentives only if they result in utility bill savings for the building occupant.[38] More clearly, estimated costs and benefits must reflect expected bill savings. Therefore, the information package must provide accurate cost information to help customers make informed decisions. Lastly, technologies or projects that are unable to reduce GHG emissions should be ineligible to receive incentives. That said, since it is also the intent of SB 1477 to help market transformation of new or emerging technologies, all technologies should be evaluated for GHG reductions prior to their participation in the program(s). SoCalGas believes that accurate information should be the priority of this program for all customers, not only those impacted by catastrophic events. Therefore, a Decarbonization Information Package with energy options, illustration of cost and benefit impacts, and associated GHG reductions is a necessary tool for evaluating participating technologies.

[36] R.18-12-005 at 2.

[37] Along with its "Green Tariff" Application, A.19-02-015, seeking authority to allow customers the option to purchase RG, SoCalGas filed over 30 letters of support from the business community. These letters demonstrate the curiosity of consumers to know their options and exercise choice in their consumption of energy.

[38] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB1477

III. CONCLUSION

SoCalGas is committed to do its part to advance the State's climate goals while prioritizing the reliability and resiliency of our energy, affordability and choice for consumers. We look forward to participating in this proceeding.

Respectfully submitted on behalf of SoCalGas,

By: ***/s/ Avisha A. Patel***
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March 11, 2019

SoCalGas Comments in Response to the IEPR Joint Agency Workshop on Energy Efficiency and Building Decarbonization & *2019 California Energy Efficiency Action Plan Draft Staff Report*, Docket #19-IEPR-06

Attachment B:

REPLY COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON ORDER INSTITUTING RULEMAKING REGARDING BUILDING DECARBONIZATION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed on January 31, 2019)

REPLY COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON ORDER INSTITUTING RULEMAKING REGARDING BUILDING DECARBONIZATION

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Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed on January 31, 2019)

REPLY COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON ORDER INSTITUTING RULEMAKING REGARDING BUILDING DECARBONIZATION

Pursuant to the Order Instituting Rulemaking Regarding Building Decarbonization filed by the California Public Utilities Commission (Commission), Southern California Gas Company (SoCalGas) hereby submits its reply comments on the Order Instituting Rulemaking (OIR).

I. INTRODUCTION AND SUMMARY OF KEY COMMENTS

SoCalGas supports a building decarbonization strategy that allows the State to maintain a diverse portfolio of energy options. Californians currently rely on a balanced energy system that is reliable, resilient, and strives to remain affordable while providing consumer choice. SoCalGas encourages the Commission and parties to support an integrated and holistic approach to reducing greenhouse gas (GHG) emissions in the building sector to promote and sustain these values currently embodied in California's energy portfolio. While it may be easy to fixate on a one-track approach, such as electrifying end uses, California should support an inclusive energy strategy that objectively considers all options and encourages current and future innovation to achieve and sustain GHG emissions reductions in the long run. Building decarbonization solutions should be practical in terms of cost and adoption to effectuate consumer acceptance, and furthermore create a framework that is scalable and exportable.

II. BALANCED AND CLEAN ENERGY SOLUTIONS FOR THE FUTURE

California's energy policy goals are focused on emissions reductions to achieve climate stabilization. The long-term goal is total, economy-wide carbon neutrality by 2045.[1] California's

[1] Executive Order B-55-18, a*vailable at:*

goal for buildings is to reduce GHG emissions from the State's residential and commercial building stock by at least 40% by 2030.[2] The method to attain this goal is not, however, a mandated single solution, such as building electrification. To achieve our State's GHG emissions reduction goals, SoCalGas agrees with the many parties advocating that the Commission develop rules, policies, and procedures that consider a balanced, multifaceted approach that will ensure Californians have access to clean, safe, reliable, and affordable energy well beyond 2045.

Southwest Gas notes that "a balanced mix of energy solutions promotes energy certainty, innovation, leveraging of energy markets, and customer choice."[3] The Coalition for Renewable Natural Gas (RNG Coalition) points out that "[Renewable Natural Gas (RNG)], by virtue of the fact that it can be stored over long time periods and dispatched, makes it a complementary and necessary resource, especially when paired with other forms of renewable power derived from intermittent resources. A truly diverse energy portfolio of decarbonization technologies should include and take advantage of the environmental and economic benefits associated with increased utilization of RNG."[4] The California Public Advocates Office (Cal PA) agrees:

> [A]nother pathway to achieve building decarbonization is through the expansion of the supply of renewable natural gas to meet part of building gas demand. Results from a study commissioned by the [California Energy Commission] CEC, *Deep Decarbonization in a High Renewables Future*, indicate that achieving a 100 percent zero-carbon generation mix is cost prohibitive without reliance on nuclear, carbon capture and sequestration (CCS), low cost abundant biofuels, or new forms of low-cost long duration energy storage…. Given the findings from these studies, the Public Advocates Office recommends that the Commission examine the potential of renewable gas as part of building decarbonization strategy to meet the State's GHG emissions reduction goals.[5]

In this proceeding, the Commission's primary objective must be to examine all options to achieve the State's climate goals and factor in other relevant priorities, including energy reliability and resiliency, affordability, and consumer choice.

https://www.gov.ca.gov/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf
[2] Assembly Bill 3232, *available at*: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB3232
[3] Southwest Gas' Opening Comments at 5.
[4] RNG Coalition's Opening Comments at 6.
[5] Cal PA's Opening Comments at 12-13.

III. A DIVERSE PORTFOLIO OF SOLUTIONS BEST ACHIEVES SHORT- AND LONG-TERM CLIMATE GOALS

Southern California Edison (SCE) references their Clean Power and Electrification Pathway as a "blueprint for California to reduce GHG emissions" by electrifying roughly one-third of space- and water-heating in buildings by 2030.[6] SoCalGas believes SCE's proposal jeopardizes reliability and resiliency, usurps customer choice, and imposes unnecessary costs.[7] The Commission's goal in this proceeding should be to maintain an inclusive approach to lower the carbon intensity of buildings—one that is technology neutral, welcomes all ideas, considers all forms of energy, prioritizes the reliability and resiliency of California's energy portfolio, encourages and allows for current and future innovation, and factors in the cost and affordability of energy. This includes thinking more broadly about other forms of renewable energy, such as renewable gas (RG), which comprises renewable natural gas (RNG), syngas derived from the gasification of forest and agricultural waste, and hydrogen.

RG is a clear and practical choice to help California achieve the goals of Senate Bill (SB) 1383 because it addresses more than 80 percent of California's methane emissions, which come from agriculture, dairies, landfills and waste water.[8] We can capture those emissions (preventing them from going into our atmosphere) and convert them to RG to heat our homes and cook our food. SoCalGas recently announced our vision to be the cleanest natural gas utility in North America. We are taking a bold step to help address fugitive methane emissions from the waste and agriculture sector by planning to replace 20 percent of our traditional natural gas supply with RNG by 2030.[9] In order to leverage and increase the benefits of these efforts, the Commission should examine the potential of RNG as part of the building decarbonization strategy to meet the State's GHG emissions reduction goals. Switching out the fuel we use in buildings with a renewable option, rather than switching out infrastructure, results in less disruption to ratepayers and "assures Californians' access

[6] SCE's Opening Comments at 6.

[7] Additionally, electrification is not a solution to addressing other building emissions. As Energy Solutions noted in their opening comments, "The scope of building decarbonization should include the full set of building emissions that are feasible to account for" and that includes "all on-site fugitive emissions from refrigerants..." Energy Solutions' Opening Comments at 4.

[8] See 2016 Methane Emissions, *California Greenhouse Gas Emission Inventory - 2018*, California Air Resources Board (CARB), *available at:* https://www.arb.ca.gov/cc/inventory/data/data.htm

[9] See *SoCalGas Announces Vision to Be Cleanest Natural Gas Utility in North America*, SoCalGas (March 6, 2019), *available at:* https://www.socalgas.com/energy-vision

to safe and reliable utility infrastructure and services" in accordance with the Commission's mission.[10] A number of other parties to this proceeding, including Cal PA,[11] the California Hydrogen Business Council (CHBC),[12] the Environmental Defense Fund (EDF),[13] Pacific Gas and Electric Company (PG&E),[14] and Southwest Gas,[15] also support exploring the potential of renewable fuels like RNG or hydrogen to assist us in reducing our reliance on fossil-based natural gas and achieve the State's climate goals.

Consumers want choice. SoCalGas not only wants to preserve that choice, but also wants to offer their customers the option to purchase RNG as part of their natural gas service. SoCalGas agrees with EDF that the Commission should broadly consider how its building decarbonization efforts may coordinate with voluntary tariff offerings. In fact, SoCalGas has already sought authority to offer a voluntary RNG tariff to customers beginning in 2020.[16] SoCalGas also agrees with EDF that building decarbonization through fuel substitution, such as the addition of RNG and hydrogen, should be explicitly included within the scope of this proceeding.[17] Retaining existing gas equipment and replacing traditional gas with carbon-neutral renewable gas is a more cost-effective option in the long run for many customers and has the added benefit of not requiring any change on their part.

Additionally, SoCalGas supports the production and use of hydrogen in California. Hydrogen as an energy source has favorable emissions characteristics because it does not contain carbon or produce carbon dioxide (CO_2) when it is consumed. Hydrogen energy and storage technologies from renewable sources can play a critical role in supporting California's grid reliability and the integration of increasing levels of renewable energy onto the regional electric grid, thereby assisting to meet California's ambitious GHG emissions goals. Power-to-Gas (P2G) technology is a way to store energy through renewable hydrogen produced from renewable electricity using a process known as electrolysis. This green electrolytic hydrogen is a carbon-free

[10] See the CPUC Mission Statement, *available at* http://www.cpuc.ca.gov/general.aspx?id=1034
[11] Cal PA's Opening Comments at 2.
[12] CHBC's Opening Comments at 3-4.
[13] EDF's Opening Comments at 13 ("The Commission should consider the role of biomethane, hydrogen, or other alternatives to fossil gas when electrification is not technically or economically feasible...") *Id*.
[14] PG&E's Opening Comments at 8-10.
[15] Southwest Gas' Opening Comments at 5.
[16] Green Tariff Application (A).19-02-015.
[17] EDF's Opening Comments at 4.

source of energy that can be used to decarbonize multiple sectors of the economy, including power generation, energy storage, transportation, and residential and commercial heating. P2G technology has the potential to address system reliability challenges that the California Independent System Operator (CAISO) faces with the large-scale integration of solar photovoltaic (PV) generation on the electric grid (also known as the "duck curve").[18] The rapid rise of solar and wind generation has created challenges with managing the electric grid. Solar and wind production frequently exceeds electrical demand, and there is limited ability to store this surplus energy optimally.[19] In the absence of a comprehensive energy storage solution, CAISO curtails these renewable sources, resulting in missed opportunities to utilize these valuable renewable energy resources. P2G prevents curtailment of high penetrations of variable renewable generation by making use of surplus renewable electricity, which otherwise would be wasted, by storing it for later use as needed in any of several applications. Battery technology offers storage solutions measured in hours, whereas hydrogen storage of electricity is measured in years. As California is faced with an increasingly urgent need to deploy utility-scale energy storage solutions to support intermittent renewable power generation, P2G must be evaluated rigorously for its potential to serve as a large-scale storage option and for its potential to help decarbonize the fuel we use in buildings via hydrogen-blending.

With the appropriate regulatory, technical and financial frameworks, California can scale up the production of RG to achieve the State's GHG emissions reduction goals. Just as government investment and financial incentives helped drive down the price of solar PV and wind generation, this proceeding could be a catalyst for stimulating investments in RG feedstocks and hydrogen production technologies which could drive down the costs of RG production.

As noted by RNG Coalition in opening comments, "[c]apture and conversion of methane from society's waste streams and redeeming it for productive end-use epitomizes sustainability."[20] Resource sufficiency is not an issue. According to a UC Davis research report, almost 100 billion cubic feet per year (Bcf/y) of anaerobically digested RNG is available in California today.[21] If the

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[18] See *Fast Facts: What the duck curve tells us about managing a green grid*, California ISO, *available at:* https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[19] See *Impacts of Renewable Energy on Grid Operations*, California Independent System Operator (May 2017) at 1, *available at:* https://www.caiso.com/Documents/CurtailmentFastFacts.pdf

[20] RNG Coalition's Opening Comments at 7.

[21] See *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*, UC Davis Institute of Transportation Studies (June 2016) at ix, *available at*: https://steps.ucdavis.edu/wp-content/uploads/2017/05/2016-UCD-ITS-RR-16-20.pdf

State wants to consider gasification of dead trees and agricultural by-products, that in-state RNG availability assessment could increase by another 100 Bcf/y[22] to 200 Bcf/y. If we consider out-of-state supplies, there could be another 1 trillion cubic feet per year (Tcf/y) available.[23] With both in-state and out-of-state supplies, gas corporations could achieve the projected statewide core procurement load of 540 Bcf by 2030;[24] this does not even count hydrogen produced from electrolysis, steam-methane reformation of biomethane, or traditional natural gas using carbon capture and utilization[25]—all of which can help the State achieve carbon neutrality by 2045.

Utilization of these in-state and out-of-state RG feedstocks is the most practical way to help the State achieve its GHG emissions reduction goals and decarbonize the fuel we use in buildings. The Commission should consider developing policies in this OIR that will further advance the deployment and adoption of diverse renewable energy solutions that will continue to provide Californians reliable, resilient, and clean energy beyond 2045. The Commission's actions in this proceeding will influence the energy supply of the future; therefore, we ask the Commission to make sound, sensible decisions that would not break the promise of hydrogen as a fuel of the future and expand the use of RG to address methane emissions from the agriculture and waste sectors, and the 140 million dead trees in our forests.[26] As noted by the National Fuel Cell Research Center (NFCRC), "[t]he development of the renewable gas market is an important goal to enable the broadest future [for] building decarbonization, while addressing the limits of lithium-ion [i.e., battery] technology. The Guiding Principle of Market Transformation can only be achieved ultimately [by] investing in renewable gas sources."[27]

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[22] See Philip Sheehy and Jeff Rosenfeld, *Design Principles for a Renewable Gas Standard*, ICF (2017) at 8, *available at:* https://www.icf.com/-/media/files/icf/white-paper/2017/icf_whitepaper_design_principles.pdf
[23] *Id*. at 10.
[24] See *2018 California Gas Report*, California Gas and Electric Utilities at 18, *available at:* https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf (297 Bcf/y for SoCalGas and 243 Bcf/y for PG&E in 2030).
[25] See *Next Generation Black Carbon Production*, Monolith, *available at:* https://monolithmaterials.com/innovative-technology/
[26] See Umair Irfan, *California Has 149 Million Dead Trees Ready to Ignite like a Matchbox*, Vox (February 15, 2019), *available at:* https://www.vox.com/2019/2/13/18221822/california-149-million-dead-trees-wildfire
[27] NFCRC's Opening Comments at 10.

IV. MAXIMIZING BENEFITS FROM EXISTING INFRASTRUCTURE PROMOTES AFFORDABILITY

SoCalGas owns and operates an integrated gas transmission system consisting of pipeline and storage facilities. Using our network of transmission pipelines and four interconnected storage fields, we deliver natural gas to nearly 6 million residential and business customers. The gas transmission system extends from the Colorado River on the east of SoCalGas' approximately 20,000-square mile service territory to the Pacific Coast on the west, and from Tulare County to the north to the United States/Mexico border to the south, supporting over 21 million consumers in southern California. The existing natural gas transmission and distribution infrastructure can be used to transport RG safely and reliably. Leveraging current natural gas infrastructure has the added benefit of promoting economic development and energy reliability in California by supporting the development of new renewable energy sources.

Pursuing electrification-only policies could result in unintended economic consequences. If the amount of gas we deliver through our pipes declines, the fixed costs associated with maintaining and operating our system would be spread over fewer customers and could result in higher rates for customers who continue to use gas. This concern was raised by numerous parties in opening comments, including PG&E[28] and the Coalition of California Utility Employees (CUE).[29] CUE detailed some of the "unintended consequences," such as fewer gas customers paying for existing required infrastructure. CUE also notes two problems: (1) a "smaller pool of customers will have to foot the whole cost by paying more … [which] will adversely impact millions of homes and businesses that depend on gas for space heating, water heating and cooking," and (2) "[t]he revenue won't be enough to cover the costs to pay workers to maintain the system."[30] For this reason, CUE cautions that the Commission "must conduct a robust analysis of impacts from building decarbonization on existing natural gas infrastructure safety, maintenance and maintenance costs, energy reliability, impacts on rates, impacts of higher prices on consumers and industry, and impacts on workers."[31] We concur with these parties on this point.

There may be other consequences to forcing a single solution, especially if it is not adopted by customers. For example, if new mandates are issued and natural gas-fueled appliances are no

[28] PG&E's Opening Comments at 9-10.
[29] CUE's Opening Comments at 2-5.
[30] *Id*. at 3.
[31] *Id*. at 2.

longer available for purchase in California, customers could find simple workarounds, e.g., driving to a neighboring state or repairing the appliance so they can continue to use natural gas to cook their food and heat their home. Similarly, penalties for having natural gas appliances (either actual or *de facto* penalties by way of electric incentives) and limited natural gas distribution service could cause home value/pricing issues when two classes of homes are effectively created (i.e., those with gas, and those without). The State is readily aware of the difficulty in decommissioning or retiring energy assets (e.g., a single nuclear plant). The widescale decommissioning of all the natural gas assets (and their related in-home counterparts) could have an undiscernible effect. Even more, customers would have to pay to decommission a well-functioning, reliable, and affordable energy delivery system while also paying the additional electric transmission and distribution costs that building electrification will add to already-high electric rates.

The National Resources Defense Council (NRDC), Sierra Club, CHBC, and others express concern about stranded investments in the gas system and making unproductive investments that may not ultimately help the State meet its climate goals.[32] However, their singular focus on electrification is a greater risk to the achievement of the State's climate goals because it fails to address crucial questions about energy storage and ignores the role existing assets can play in providing such storage while preserving reliability, resiliency, affordability, and consumer choice.

Ultimately the Commission is tasked with exploring all strategies that support a cost-effective, equitable and viable clean energy future. The Commission should adopt policies that protect customers, not burden them. The question of who should pay for "stranded" gas assets can be avoided by shifting our mindset to consider ways we can continue to utilize the existing pipeline system to deliver renewable energy (such as RG). This is a proposal the Commission must explore in this proceeding.

V. SUSTAINABILITY REQUIRES CONSUMER ADOPTION, WHICH IN TURN REQUIRES CHOICE AND AFFORDABILITY

Without consumer adoption, building decarbonization policies cannot succeed. Homeowners, apartment owners and developers are crucial to a successful program focused on reducing GHG emissions from residential buildings. The Commission should give serious consideration to both the direct and indirect effects of its new policies on the single largest investment people will make over their lifetime (i.e., their home). Customers should have cost-effective options and must be able to

[32] NRDC/Sierra Club's Opening Comments at 4-5 and CHBC's Opening Comments at 7.

choose which technologies or fuels provide the best solutions for their family. Southwest Gas correctly notes the importance that "solutions ultimately adopted to help accomplish the State's goals toward carbon neutrality are effective, adoptable, scalable, and affordable, while also promoting and maintaining energy reliability, resiliency and consumer choice."[33] The Wild Tree Foundation correctly points out that California "emits only a small fraction of global GHG emissions;" thus, for a building decarbonization program to be meaningful, it must be a model that can be exported and "replicated around the country and the world."[34] The Association of Bay Area Governments on behalf of BayREN agrees: "New technologies should be evaluated based on their ability to maximize reductions in greenhouse gas emissions *and the scalability of the technology*."[35]

Palo Alto's heat pump incentive program is a good example of how difficult it can be to get people to adopt new technologies. The City of Palo Alto "has offered a rebate of up to $1500 per heat pump water heater since mid-2016. Since the program launch, the uptake rate of this rebate is at about 0.1 % per year among single family homes."[36] Even a city with one of the highest median home-sale prices in the nation and home to a large number of forward-thinking technology companies, including Hewlett Packard, Tesla, Apple, Facebook and PayPal, has been challenged by consumer adoption. If the City of Palo Alto had instead used this incentive money on RNG, they could have decarbonized 3,750 homes for one year. The point is simple: there is more than one way to achieve building decarbonization. Several commenting parties note the pitfalls of complex regulatory schemes and subsidizing markets, but these characterizations do not make sense.[37]

RG not only can be a carbon negative fuel; it also has the distinct advantage of providing climate stabilization benefits without requiring consumer adoption of new appliances or costly home conversions. Consumers can keep their appliances of choice and would not be forced to adopt technologies that are not sensible for their homes or families. Building decarbonization using RG is a win-win for both homeowners and the State. As one party notes in comments, "[i]f RNG and other viable technologies are provided a level playing field on which to participate and compete, the

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[33] Southwest Gas' Opening Comments at 2.
[34] Wild Tree's Opening Comments at 3.
[35] BayREN's Opening Comments at 6 [emphasis added].
[36] City of Palo Alto's Opening Comments at 4.
[37] CHBC's Opening Comments at 3.

overarching program will *minimize consumer costs* and ensure the most optimal path toward achieving the State's greenhouse gas reduction goals."[38]

Several other parties recognize the vital role cost and affordability play in sustainability and fairness. The County of Los Angeles, on behalf of the Southern California Regional Energy Network (SoCalREN), explains that another guiding principle in this case should include "cost impacts" for any new rules or policies that may significantly impact customers within disadvantaged communities or low-to-moderate income households.[39] SoCalREN emphasizes the need to be mindful of "any undue cost burdens that these new policies, rules and procedures may place among those most underserved."[40] The California Housing Partnership points out that "[a]ffordable housing property owners also have limited resources available at their disposal to install measures that don't bring in high savings."[41]

Another critical component to sustainability is that the solutions reached in this proceeding must guarantee resiliency and reliability because energy is required every minute of every day. Reliability and resiliency must not be compromised in State energy planning efforts. The NFCRC notes that "[r]esiliency and reliability should be simultaneously achieved by introducing new technologies for building decarbonization."[42] Citing the 2019 IEPR Update Scoping Order, NFCRC notes there are "differing vulnerabilities to the natural gas and electricity sectors" and "flexible and adaptive strategies to increase the state's resilience to multiple stressors from climate change on the energy system, with particular attention to vulnerable populations."[43]

VI. DIFFERENT PROGRAM ADMINISTRATORS ARE REQUIRED FOR DIFFERENT PROGRAMS

Multiple parties offer suggestions for third-party administrators, and SCE suggests that an electric IOU would be appropriate. As part of its evaluation, the Commission should take into consideration the success and/or failures of the numerous programs and/or projects managed by different entities. The primary focus on selecting the appropriate program administrator should be to safeguard ratepayer investments and ensure programs are designed, implemented, and administered

[38] RNG Coalition's Opening Comments at 8 [emphasis added].
[39] SoCalREN's Opening Comments at 2.
[40] *Id*. at 3.
[41] California Housing Partnership's Opening Comments at 6.
[42] NFCRC's Opening Comments at 9.
[43] *Id.* at 9-10, citing *2019 Draft Scoping Order for the 2019 Integrated Energy Policy Report*, California Energy Commission, (February 14, 2019) at 4.

to the best interest of ratepayers and the State's climate goals. At minimum, the program administrator should be a reputable entity subject to the CPUC's Rules of Practice and Procedure.

SoCalGas believes the BUILD program is best suited to be administered locally, while the TECH program may benefit from a single statewide administrator. Home builders and developers, who are the intended recipients of the incentives provided by the BUILD program, largely operate on a regional basis, which enables coordination with municipal planning departments, local utilities, and local agencies. They also are adept at working with utility planning departments for meter sets and line extensions as well as energy efficiency programs which promote more efficient home design and zero net energy buildings. For the BUILD program to be successful, it must leverage existing utility energy efficiency programs at the local level to magnify the available incentives and amplify the energy savings and emissions reductions.

The TECH program has a different target, primarily the identification of barriers for high-efficient technology adoption and working with manufacturers and retailers to overcome these barriers. This program may be more suitable as a statewide approach; however, coordination with local utility energy efficiency programs will still be critical for successful implementation of the program. In this regard, SoCalGas agrees with Southwest Gas that the individual utilities are best positioned to administer the BUILD and TECH programs prescribed in SB1477. Southwest Gas notes that it is most familiar with its customers, procedures and existing programs, and is best situated to administer the new programs most effectively within its own service territory. The same holds true for SoCalGas and the other funding gas corporations.

Cal PA errs in its assessment of the intent of the SB1477 program. Cal PA states that "[t]he programs should not be administered by a gas corporation because of the inherent conflicts of interest in programs designed to switch customers away from using natural gas." This assumes SB1477 is about switching customers away from natural gas, which it is not. The intent of SB1477 is to focus on incentivizing technologies that are more efficient than those that are currently contained in Title 24, Part 6 building efficiency standards. This includes gas, electricity, propane, and other fuels. The narrow view that this is a program intended to switch building technologies from natural gas to electric is not only incorrect, but such a singular view could prevent California from achieving its emissions reduction goals. Instead, the Commission should look to implement a fuel-neutral program that focuses on multiple energy sources and technologies covered by the legislation to improve energy efficiency and reduce GHG emissions. Other parties have the right approach. The California Municipal Utilities Association (CMUA) requests that "the Commission promote a broad and inclusive approach to evaluating technology opportunities."[44] Only a broad approach will establish a framework by which California will achieve its ambitious goals in a thoughtful and cost-effective manner. Furthermore, the Commission should be mindful of the source of these funds, namely natural gas ratepayers, and pursue a program that conforms to the long-standing practice that gas ratepayers receive the benefits of the programs they are funding.

Cal PA's contention regarding a conflict of interest is an unsupported generalization. SoCalGas supports California's efforts to decarbonize its energy system. This should be done in a thoughtful, cost-effective manner that provides all Californians an energy system that is resilient, reliable, and provides affordable energy options for customers. Cal PA seems to presume that an electric utility would have no conflict of interest in this matter; however, an electric utility could utilize Cal PA's narrow view of SB1477 as an opportunity to build electric load, not taking into account overall GHG reductions, nor mindful of the ramifications of increased energy costs for customers, nor considering the potential negative consequences of an energy system that lacks resiliency.

SCE appropriately acknowledges the $200 million allocated to the BUILD and TECH programs over the implementation period is a first step in the funding needed to improve California's clean energy infrastructure. While SCE notes its accomplishments in its opening comments on successfully running Commission-approved programs, SoCalGas has implemented programs through partnerships that have been critical to their success. The ability to partner with stakeholders, local governments, electric utilities, water agencies, air quality districts, and numerous other entities will increase the likelihood of the success of these programs. As noted in opening comments, SoCalGas has been nationally recognized for its ability to bring together like-minded partners to leverage additional funding and magnify the effects of incentive programs and services for customers. The Commission will need that ability to ensure success in these programs. The Commission can rely on SoCalGas' commitment to bringing these full resources to bear in this effort.

[44] CMUA's Opening Comments at 2.

VII. FUEL AND TECHNOLOGY NEUTRALITY IS CRITICAL FOR CALIFORNIA'S ENERGY POLICY

SoCalGas agrees with EDF that the Commission should broadly consider how its building decarbonization efforts may coordinate with voluntary tariff offerings. SoCalGas has already sought authority to offer a voluntary RNG tariff to customers beginning in 2020.[45] SoCalGas also agrees with EDF that building decarbonization through fuel substitution, such as the addition of RG, should be explicitly included within the scope of this proceeding[46] because retaining existing gas equipment and replacing traditional gas with carbon-neutral renewable gas is a more cost-effective option in the long run for many customers and has the added benefit of not requiring any change on their part.

Other parties also recognize the importance of a technology-neutral approach. The NFCRC notes that "[l]imiting the program focus only on certain technologies could limit program effectiveness in reducing GHG emissions."[47] NFCRC cites research by the University of California, Irvine that electric heat pumps may actually *increase* GHG emissions.[48] Along the same lines, SoCalGas agrees with NFCRC's point that "[f]uel cells decarbonize buildings and do so while providing always-on reliable power," which is critical for vital industries like healthcare providers, data centers, and advanced manufacturing.[49] Comments provided by the California Efficiency and Demand Management Council (Council) note the goal of this proceeding should be to "lay the groundwork for a thriving marketplace of new technologies, appliances, and strategies that industry can implement to achieve the Commission's and state's long-term [] emissions goals."[50]

VIII. OTHER CONSIDERATIONS

A. The cost to ratepayers matters and must guide the Commission in this proceeding

While the BayREN advocates that metrics should diminish the importance of costs and instead focus on GHG reduction potential,[51] this is not a fair proposal for many Californians. Over a third of SoCalGas' customers qualify for California Alternate Rates for Energy (CARE), which provides a 20% rate discount for eligible customers. For these customers, cost matters and the Commission must ensure customers have carbon-neutral options that do not require appliance

45 Green Tariff Application A.19-02-015.
46 EDF's Opening Comments at 4.
47 NFCRC's Opening Comments at 4.
48 *Id*.
49 *Id.* at 7.
50 Council's Opening Comments at 7.
51 BayREN's Opening Comments at 6-8.

replacement and expensive panel and wiring upgrades. In the case of renters or non-owners who also pay utility bills, the Commission must carefully consider the consequences of policies that involve, either directly or indirectly, the transfer of funds from one customer group to another that could result in disproportionate economic impacts.

NFCRC explicitly notes, and it is self-evident, that "[d]ecarbonization is not synonymous with electrification."[52] Nevertheless, some parties focus on electrification as the exclusive method for decarbonization without even acknowledging the important role carbon-neutral RG can play in decarbonizing buildings. Similarly, while some parties discuss the importance of prioritizing incentives for low-income and disadvantaged communities, they do not address the issue of unintended consequences from an equity, jobs, consumer prices and energy affordability perspective. CUE's comments address this issue in a manner that the Commission should carefully consider in order to avoid negative impacts on housing costs and jobs: decarbonization policies should not replace good middle-class jobs with poverty-wage, dead-end jobs.[53]

SoCalGas agrees with NRDC and Sierra Club that, as a guiding principle to ensure fair competition among technologies, strategies should be identified in this proceeding that will *most economically* reduce GHG emissions in line with the statewide goal of achieving carbon neutrality by 2045. This includes the need for large amounts of electricity storage in a renewable electricity scenario and the singular role that the natural gas pipeline system can play in providing long-term storage at the terra-watt level. The existing gas infrastructure, in which we have already invested significant resources, is a great resource for fully realizing renewable and carbon-neutral energy initiatives. The current system can transmit and distribute RG without costly upgrades.

B. Despite some parties' statements, there is no current consensus on how to solve GHG in California

In opening comments, NRDC and Sierra Club reference the CEC's 2018 Integrated Energy Policy Report (IEPR) Update, which identifies building decarbonization as the next clean energy policy priority for California to achieve its climate goals. NRDC and Sierra Club note "[t]he IEPR concludes that due to the availability of 'off-the-shelf, highly efficient electric technologies (such as heat pumps) and the continued reduction of emission intensities in the electricity sector,' there is 'a

[52] NFCRC's Opening Comments at 6.
[53] CUE's Opening Comments at 5.

growing consensus that building electrification is the most viable and predictable path to zero-emission buildings.'"[54] SoCalGas respectfully disagrees. It is unclear how "consensus" has been measured and, moreover, it is inconsistent with feedback received from natural gas-users.[55] The Commission should not be swayed by the broad recommendation made by the CEC and should make policy decisions that are based on science and are analyzed and vetted for cost and economic impact before they are adopted.

IX. CONCLUSION

SoCalGas encourages the Commission to explore all options to achieve the State's climate change goals while prioritizing the reliability and resiliency of our energy, affordability, and consumer choice. The policies determined in this proceeding will likely create a blueprint for California's energy future and influence GHG emissions reduction policies adopted across the country and around the world; thus, every viable option must be examined before determining the best path forward. We look forward to participating in this proceeding.

Respectfully submitted on behalf of SoCalGas,

By: ***/s/ Avisha A. Patel***
Avisha A. Patel

CHRISTOPHER BISSONNETTE
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March 26, 2019

[54] NRDC/Sierra Club's Opening Comments at 2.

[55] See *CBIA Announces Findings on High Cost of Electrifying Homes and Californians Preference for Natural Gas*, Press Release, California Building Industry Association, (April 23, 2018) *available at:* http://www.biabuild.com/latest-news/2018/4/24/cbia-announces-findings-on-high-cost-of-electrifying-homes-and-californians-preference-for-natural-gas

SoCalGas Comments in Response to the IEPR Joint Agency Workshop on Energy Efficiency and Building Decarbonization & *2019 California Energy Efficiency Action Plan Draft Staff Report*, Docket #19-IEPR-06

Attachment C

Pacific Gas and Electric Company

Erik Jacobson
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

June 14, 2019

Advice 4106-G
(Pacific Gas and Electric Company ID U 39 G)

Public Utilities Commission of the State of California

Subject: Summary of PG&E's Progress Assessing the Feasibility of Options for Providing Affordable Clean Energy to Monterey Park Tract

Purpose

Pursuant to Ordering Paragraph (OP) 2 of California Public Utilities Commission (CPUC or Commission) Decision (D.) 18-12-015, issued on December 19, 2018, Pacific Gas and Electric Company (PG&E) submits this Tier 1 Advice Letter (AL) for its Summary of PG&E's Progress Assessing the Feasibility of Options for Providing Affordable Clean Energy to Monterey Park Tract (Monterey Park Tract Feasibility Study), as shown in Attachment A.

Background

In 2015, the Commission initiated a rulemaking to identify disadvantaged communities in the San Joaquin Valley, and then to evaluate the feasibility of options to improve access to affordable energy in these communities.[1] To assist the Commission in addressing these goals, D.18-12-015 approved pilots in eleven San Joaquin Valley Disadvantaged Communities (SJVDAC) and deferred approval of a 12th pilot in Monterey Park Tract (MPT).

The feasibility study is for further exploring and developing the renewable natural gas microgrid or tank pilot project for MPT, with an emphasis on securing a dairy digester partner and more thoroughly assessing the costs and timeline of a proposed MPT project, and consulting with Turlock Irrigation District and the California Energy Commission regarding the potential for electrification of MPT.

[1] *Order Instituting Rulemaking to Identify Disadvantaged Communities in the San Joaquin Valley and Provide Economically Feasible Options for Affordable Energy,* R. 15-10-030, p. 2 (April 3, 2015).

Regarding a PG&E proposal for a gas microgrid pilot in MPT,[2] the Commission ordered:

> We direct Pacific Gas and Electric Company (PG&E) to further explore and develop the renewable natural gas microgrid or tank pilot project for Monterey Park Tract (MPT), with an emphasis on securing a dairy digester partner and more thoroughly assessing the costs and timeline of the proposed project; consult with Turlock Irrigation District and the California Energy Commission regarding the potential for electrification of MPT; and file a summary of its progress assessing the feasibility of options for providing affordable clean energy to MPT….[3]

Request

PG&E requests the Commission to adopt its final recommendation to approve the MPT pilot as described in its Monterey Park Tract Feasibility Study provided in Attachment A to this advice letter.

Protests

Anyone wishing to protest this submittal may do so by letter sent via U.S. mail, facsimile or E-mail, no later than July 5, 2019, which is 21 days[4] after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

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[2] D. D.18-12-015, pp.47-50.
[3] *Id.* p. 161 (OP 2).
[4] The 20-day protest period concludes on a holiday, therefore, PG&E is moving this date to the following business day.

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

Pursuant to OP 2 of D.18-12-015, this Advice Letter is subject to Energy Division disposition and should be classified as Tier 1, Effective Pending Disposition, pursuant to General Order (GO) 96-B. PG&E respectfully requests this Advice Letter be effective June 14, 2019, which is the date submitted.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for R.15-03-010. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Erik Jacobson
Director, Regulatory Relations

Attachments

cc: Service List R.15-03-010

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39 G)

Utility type:
- ☐ ELC
- ☑ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Annie Ho
Phone #: (415) 973-8794
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: AMHP@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 4106-G Tier Designation: 1

Subject of AL: Summary of PG&E's Progress Assessing the Feasibility of Options for Providing Affordable Clean Energy to Monterey Park Tract

Keywords (choose from CPUC listing): Compliance,

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.18-12-015

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 6/14/19 No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected:

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Erik Jacobson, c/o Megan Lawson Title: Director, Regulatory Relations Utility Name: Pacific Gas and Electric Company Address: 77 Beale Street, Mail Code B13U City: San Francisco, CA 94177 State: California Zip: 94177 Telephone (xxx) xxx-xxxx: (415)973-2093 Facsimile (xxx) xxx-xxxx: (415)973-3582 Email: PGETariffs@pge.com
	Name: Title: Utility Name: Address: City: State: District of Columbia Zip: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

Clear Form

Advice 4106-G
June 14, 2019

Attachment A

Monterey Park Tract Feasibility Study

PACIFIC GAS AND ELECTRIC COMPANY

SAN JOAQUIN VALLEY DISADVANTAGED COMMUNITIES OIR REPORT

R.15-03-010

PG&E San Joaquin Valley Disadvantaged Communities Monterey Park Tract Feasibility Study

JUNE 17, 2019

Contents

PG&E SJV DAC Monterey Park Tract Feasibility Study

Introduction and Summary of Recommendation to Approve Microgrid Proposal

This Feasibility Study describes the additional steps Pacific Gas and Electric Company (PG&E) performed to further explore the opportunities to serve the Monterey Park Tract (MPT) community, a San Joaquin Valley (SJV) Disadvantaged Community (DAC), as ordered by the California Public Utilities Commission's (Commission) Decision (D.) 18-12-015 (the Decision).

In 2018 PG&E submitted a proposal to develop a local gas distribution network to serve the MPT community that would ultimately be fed using Renewable Natural Gas (RNG) from a local source. Consistent with D.18-12-015, PG&E has further explored the opportunities at MPT with a focus on the local RNG source, which would not be covered by the proposed SJV DAC pilot budget for MPT. PG&E hired Black & Veatch (B&V)[1] and Gladstein, Neandross and Associates (GNA)[2] to provide expert consultation for this work.

PG&E finds the dairy digester to be a viable economic option for serving MPT: when comparing the cost analysis provided by B&V with the Incentives Report from GNA, PG&E finds that the simple payback period could be less than three years, which is highly favorable. Leveraging incentive programs for the dairy digester and the refueling station, including credits from for Low Carbon Fuel Standard (LCFS) credits and Federal Renewable Fuel Standard (RFS), for costs not covered within the SJV DAC proceeding make this project worth pursuing. Not only does the proposal have a strong economic outcome, it also helps reduce greenhouse gas (GHG) emissions and improve the air quality in the surrounding community.

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[1] B&V is an employee-owned engineering, procurement, consulting and construction company, which has been in business for 103 years. B&V has more than 10,000 professionals and over 100 offices worldwide, including multiple offices in California and a headquarters office in Kansas City.

As a leader in the planning and design of wastewater treatment facilities, B&V has acquired strong experience in all aspects of biogas production and utilization, including cogeneration facilities, biogas cleaning technologies, and the production of RNG. Over the last 12 years, B&V has been evaluating California dairy manure digestion opportunities, issues, technologies, and costs. B&V has been involved in the development of biogas utilization projects for decades.

[2] GNA is one of the nation's leading experts on alternative fuel and electric transportation technologies. With offices in Arizona, California, New York and Texas, GNA assists private fleets, public agencies and not-for-profit environmental organizations identify, develop and implement policies, incentives and programs to accelerate the commercialization and deployment of low, near zero and zero emission motor vehicles, off-road equipment, locomotives and ocean-going vessels. Over the last 25 years GNA has written over 400 successful grant applications for more than $610 million in awards for its clients.

As stated in D.18-12-015, the Commission's intent in approving the further exploration is to more thoroughly assess the costs and timeline of a proposed MPT project, and consult with Turlock Irrigation District (TID) and the California Energy Commission (CEC) regarding the potential for electrification of MPT with an emphasis on securing a dairy digester partner.[3] A detailed history of the legislative and procedural activity leading to the pilots is provided in the decision and not repeated here; however, PG&E does provide the Commission's stated goals and objectives for these pilots:[4]

- "The dual goal[s] of the pilots are to provide cleaner, more affordable energy options to propane and wood burning and gather real time data needed to assess the economic feasibility of extending affordable energy options to all listed SJV DACs"; and
- "The pilot objectives are as follows:
  - Gather inputs to assess cost-effectiveness and feasibility during Phase III;
  - Provide access to affordable energy options in participating pilot host communities;
  - Reduce household energy costs for participating pilot host customers;
  - Increase health, safety and air quality of participating host pilot communities;
  - Test approaches to efficiently implement interventions;
  - Assess potential scalability." [5]

PG&E believes the proposal for MPT meets all the pilot objectives as stated above. This study represents PG&E's best information as of the date of the advice letter filing; however, it is subject to change. Changes may include cost and schedule modifications depending on final vendors and developers selected to perform work if approved to proceed with the gas microgrid.

[3] D.18-12-015, pp. 49-50, 161 (Conclusion of Law 28, Ordering Paragraph 2).

[4] D.18-012-015, p. 10 (Note that page references are consistent with the version of D.18-12-015 served on December 20, 2019appended to President Picker's Dissent. A later version has slightly different pagination). Referred to throughout as the decision or SJV DAC Pilots Decision.

[5] D.18-012-015, pp. 10-11 (Note that page references are consistent with the version of D.18-12-015 served on December 20, 2019 appended to President Picker's Dissent. A later version has slightly different pagination). Referred to throughout as the decision or SJV DAC Pilots Decision.

Gas Microgrid pilot Digester Design, Cost and Timeline

PG&E took the following steps to gather additional data and explore the gas microgrid pilot project:

- PG&E engaged with a local dairy adjacent to the MPT community to partner with PG&E in serving the community;
- PG&E contracted B&V to prepare a conceptual design package, permitting matrix, cost and schedule for installing a dairy digester, biogas[6] clean up system and a public compressed natural gas (CNG) fueling station at the partner dairy;
- PG&E engaged Western United Dairymen to review the proposal and provide feedback;
- PG&E and B&V engaged multiple dairy digester developers to provide bid packages to inform the cost estimates;
- PG&E contracted GNA to provide an Incentives Report with a summary of programs that can be harnessed to provide both public and private resources for the development of dairy digester projects and associated conditioning and interconnect infrastructure to deliver dairy manure-derived RNG to the MPT Project; and
- PG&E consulted the CEC regarding potential opportunities for Research and Development (R&D) and funding for the dairy digester and microgrid proposal.

Dairy Partner

PG&E engaged with Trinkler Dairy Farms Inc. (Trinkler) whose property is adjacent to the east side of MPT, in an effort to secure a local partner dairy for the project. Trinkler is a small family-owned dairy established in 1960 and incorporated in California. Trinkler has approximately 1,500 milking cows. Trinkler is very open to helping the community and considering the concept of installing the anaerobic digester (AD), biogas clean-up system, and CNG fueling station on their property. Trinkler met with PG&E and B&V to discuss their operations and the conceptual layout of the required equipment. Additionally, Trinkler allowed PG&E to return to the dairy property to meet with one of the AD developers, walk the property and discuss the proposal with the developer.

Trinkler was unable to commit to next steps until they see the details from this filing to determine if it would financially make sense for them to move forward with the proposal. As long as it is economically beneficial for the dairy to proceed forward, Trinkler has indicated it would consider the project and continue to engage with PG&E if approved by the Commission.

Dairy Digester Conceptual Design and Production

B&V's design is based on a covered lagoon digester. Trinkler currently utilizes a flush-type manure collection system. Covered lagoon digesters typically include minimal pretreatment and conditioning of digester influent (i.e., oversized particle or bedding separation) and are unheated. Digestate from the process is typically pumped into a storage lagoon and used as an agricultural fertilizer.

[6] "Biogas" refers to the untreated gas produced from the digester. Biogas needs to be cleaned and treated before it can be transported and used in most commercial operations or injection into the pipeline system. RNG refers to biogas which has been cleaned to meet the pipeline gas quality tariff requirements.

Based on the analysis completed by B&V, using a covered lagoon AD system and membrane-based biogas cleaning system an RNG production rate of 37,200 to 39,500 thousand cubic feet (MCF) per year was estimated. The MPT community would use very small portion of this total production, estimated at 1,815 MCF/year or approximately 5 percent.[7] Figure 1 below shows the estimated RNG production at Trinkler based on the Mass and Energy balances:

FIGURE 1
Dairy Mass and Energy Balance Summary

PARAMETER	UNITS	SUMMER	WINTER
Combined Flow from Barns	lb/hr	110,091	134,700
Influent to Digester	lb/hr	107,130	131,078
Raw Biogas Production	scfm	122.3	115.1
RNG to MPT	scfm	2.5	2.5
RNG to Local Refueling	scfm	13.3	13.3
RNG to Tube Trailers	scfm	63.4	58.7
Total RNG	**MCF/yr**	**39,500**	**37,200**

Dairy Digester Major Tasks and Timeline

The primary tasks completed by B&V on behalf of PG&E to further assess the opportunity to install a dairy digester to serve the MPT community with RNG included:

- Gather data specific to dairy operations
- Design package:
  - Process flow diagrams / heat material balances
  - Equipment list
  - Electrical one-line and load list
  - General arrangement drawing
- Prepare Environmental Permitting matrix
- Prepare a Schedule and Cost estimate
  - EPC schedule
  - Capital cost
  - Operations and maintenance cost

[7] Estimated usage is based on usage in similar sized homes with natural gas service five miles away in Ceres, CA.

From the work completed by B&V, PG&E is able to provide the estimated timeline and tasks required to install all equipment to produce the RNG and build the CNG fueling station that will serve the MPT community as ordered by D.18-12-015. The timeline in Figure 2 provides a high-level key milestone schedule from the notice to proceed (NTP) date for installing and commissioning the dairy digester and microgrid. Based on the conceptual engineering design package and expected permitting requirements, B&V developed a proposed scheduled with a 22-month duration to implement the project including permitting, engineering, procurement, construction, and commissioning.

FIGURE 2
PG&E Dairy Digester Development TIMELINE

Key Milestone Dates

PROJECT MILESTONE	DATE AFTER NTP
Permitting	12 months
Detailed Engineering	13.5 months
Procurement	18 months
Construction	21 months
Commissioning and Testing Completion	22 months
Commercial Operation Date	22 months

A more detailed timeline will be developed in consultation with Trinkler and selected developer if the project is approved to proceed forward.

Dairy Digester Estimated Costs

B&V's conceptual cost estimate is classified as an American Association of Cost Engineers[8] Class 4 estimate with an accuracy of ±30 percent. Furnish and erect packages and equipment material prices were estimated primarily using vendor budgetary quotations for the digester, biogas cleaning, and refueling systems. The balance of equipment was estimated using in-house pricing based on historical project data. All costs are expressed in 2019 United States Dollars (USD). This excludes the costs of the gas distribution facilities needed to serve the MPT community that were estimated in the initial proposal filed earlier in the proceeding. Other exclusions from this cost estimate include permitting fees, capital spares, taxes/duties, liability insurance, letters of credit/bonds, tariff impacts, hazardous materials handling/abatement, and other Trinkler costs.

[8] https://web.aacei.org/.

A capital cost range of $7,209,000 to $9,761,000 was estimated for the project, as shown in Figure 3. All labor costs have been adjusted to reflect California rates and productivity. The high end of the cost range reflects an engineering, procurement support, and construction management (EpCM) execution approach. The low end of the cost range represents a developer-led approach instead of EpCM approach, resulting in savings of approximately 25-30 percent as detailed below. Together these cost estimates indicate an approximate upper and lower range for the anticipated capital cost of the project. The cost reductions for the developer-led cost estimate include the following adjustments:

- Reduction in engineering costs within the digester design (with engineering costs taken out of the “Lagoon Digester” line item and moved to the integrated “Engineering” line item);
- Reduced labor hours and increased labor efficiency, leveraging the experience and lower blended labor costs with an experienced digester developer team engaged;
- Contingency eliminated from the budget to reflect the lower potential cost range for the project; and
- Reduced or eliminated material cost contingencies in several categories associated with no longer having a third-party EpCM integrator.

FIGURE 3
PG&E Dairy Digester Development Capital Costs[9]

DESCRIPTION	EpCM CAPITAL COST	DEVELOPER-LED CAPITAL COST
Direct Costs		
Site Work	$835,000	$835,000
Foundations and Concrete	$175,000	$162,000
Steel	$320,000	$250,000
Fire Protection System	$300,000	$150,000
Lagoon Digester	$2,279,000	$1,710,000
Biogas Cleaning System	$1,925,000	$1,500,000
Refueling System	$862,000	$854,000
Piping	$460,000	$130,000
Electrical Equipment and Bulks	$547,000	$390,000
Insulation and Painting	$62,000	$59,000
Productivity Adjustment	$124,000	$0
Total Direct Cost	$7,889,000	$6,107,000
Indirect Costs		
Construction Management and Startup Staff	$420,000	$210,000
Subcontractor Indirects	$479,000	$192,000
Engineering	$508,000	$700,000
Contingency	$465,000	$0
Total Indirect Field Costs	$1,872,000	$1,102,000
TOTAL CAPITAL COST	**$9,761,000**	**$7,209,000**

B&V also estimated Operation and Maintenance (O&M) costs for the project to be approximately $515,000 per year as shown in Figure 4. All O&M cost estimates are presented in 2019 USD. The list of assumptions made to develop the O&M estimate is provided the detailed B&V report in Attachment A.

[9] Capital Costs are in addition to the $4.1 million In Front of Meter and Behind The Meter costs identified in PG&E's microgrid proposal for the MPT community filed on October 8, 2018. The capital costs provided by B&V would be the responsibility of Trinkler.

FIGURE 4

PG&E Dairy Digester Development Operation and Maintenance (O&M) Costs[10]

DESCRIPTION	TOTAL COST
H_2S Removal Media Replacement	$43,000
Biogas Conditioning / Upgrading System Maintenance	$51,000
Refueling System Maintenance	$20,000
Electric Power	$205,000
Water Requirement	$0
Propane for Thermal Oxidizer	$19,000
Labor	$130,000
Contingency (10% of Subtotal)	$47,000
TOTAL O&M	**$515,000**

Funding, Grant and Climate Credit Opportunities for the dairy digester

GNA's Incentives Report identifies several potential financial resources that can be utilized to help support the costs associated with the development of a dairy digesters to serve MPT.

Financial Opportunities through Digester Infrastructure Programs

The following incentive programs provide funding for capital costs and/or operational expenses related to the construction and installation of digester facilities as well as associated clean up and interconnection infrastructure. Additional details regarding each program is available in the GNA report provided in the Attachment B.

- ***Community-Scale Advanced Biofuels Production Facilities.*** Community-scale projects (100,000 to 1,000,000 Diesel Gallon Equivalent (DGE))[11] are eligible for up to $3,000,000.
- ***Dairy Digester Research and Development Program.*** Awards up to 50 percent of the total project cost with a maximum grant award of $3,000,000 per project.
- ***Demonstration-Scale Advanced Biofuels Production Facilities.*** *Awards up to* 75 percent per project or $3,000,000, whichever is less
- ***FY19 Bioenergy Technologies Office Multi-Topic Funding Opportunity Announcement (AOI 9: Rethinking Anaerobic Digestion).*** *Awards up to $3 million per project.*
- ***Rural Energy for America Program (REAP).*** *Grants 25 percent of project cost up to $500,000 and $25 million loan guarantee.*

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[10] O&M Costs are in addition to the $4.1 million In Front of Meter and Behind The Meter costs identified in PG&E's microgrid proposal for the MPT community filed on October 8, 2018. These O&M costs would be the responsibility of Trinkler.

[11] 1 MCF of Natural Gas=0.1393 DGE. Projects with 13,930-139,300 MCF RNG would qualify for this program. Conversion rate available at: https://afdc.energy.gov/fuels/equivalency_methodology.html.

- ***Modified Accelerated Cost-Recovery System (MACRS).*** *Businesses may recover investments through depreciation deductions from taxes over 3-5-year depreciation period.*

Alternative Fuel Vehicle and Refueling Infrastructure Programs

A critical success factor of dairy digester projects is the ability to sell surplus RNG to the transportation sector, where it has the highest monetary value. The proposal from PG&E regarding the production of RNG to serve MPT recognizes this factor and provides the community, local businesses and residents with a public CNG fueling station on the Trinkler property along a public road. With the availability of a CNG fueling station utilizing the excess RNG, Trinkler and others in the surrounding area could convert their fleets to CNG vehicles with the support of a number of incentive programs. Trinkler could leverage some of the incentive programs to convert a portion of the Trinkler fleet to Near Zero Emission CNG vehicles to reduce costs on purchasing diesel fuel and further reducing its carbon footprint. Other local businesses and residents could also take advantage of the incentives and availability of the CNG fueling station since the station will be open to the public to purchase CNG as an alternative vehicle fuel. Additionally, the refueling infrastructure could be eligible for incentive that help expand the availability of alternative clean fuels within California and specifically in the SJV.

The following incentive programs provide funding for the purchase and deployment of low and near zero emission vehicles that could be end users of dairy RNG.

- ***Advanced Freight and Fleet Technologies Program.*** *Program is under development and expected to open in the third quarter of 2019. The anticipated incentive would likely include charging infrastructure development.*
- ***California VW Program for Combustion Freight and Marine.*** *Applicants may be eligible for $35,000-85,000 per ultra-low NOx class 7 or 8 vehicle, depending on size, ownership, and project type.*
- ***Drive Clean! Rebate Program.*** *25 percent of total vehicle cost up to $3,000 to SJV residents and businesses for the purchase of new, clean-air vehicles.*
- ***Goods Movement Emission Reduction Projects (Proposition 1B Program).*** *Grants up to $100,000 per heavy-duty natural gas vehicle. Eligible costs include capital costs of purchasing a new vehicle and/or the equipment and installation costs for new fueling infrastructure.*
- ***Hybrid and Zero Emission Truck and Bus Voucher Incentive Project (HVIP) – Low NOx Incentives.*** *Incentives up to $45,000 per natural gas vehicle.*
- ***National Clean Diesel Funding Assistance Program.*** *Incentives up to 45 percent of vehicle replacement costs.*
- ***New CNG Infrastructure Program.*** *Program under development. Expected to open Q3 2019 and provide incentives for Capital costs associated with purchase and installation of refueling equipment.*
- ***Targeted Air Shed Grant Program.*** *Up to $3 million grant funding for the capital costs associated with the purchase/lease of new vehicles and/or refueling infrastructure.*
- ***Truck Replacement Program.*** *Up to $100,000 per Natural Gas Truck.*
- ***Clean School Bus Rebate Program***. *$15,000 per Class 3-5 bus and $20,000 per Class 6-8 bus.*
- ***Public Benefit Grant Program – New Alternative Fuel Vehicle Purchase.*** *Up to $20,000 per purchase of new alternative fuel vehicles for public agencies to promote clean air alternative-fuel technologies.*

Non-Energy Value Revenue Incentive Programs

Monetary incentives are also available for the RNG produced that is used for vehicle fuel, as proposed. The revenue generated for these non-energy revenue streams provides a substantial incentive and makes the economics of diary digester development viable. Given the predicted RNG production rate of 37,200 to 39,500 MCF/year, the volume of RNG used as a transportation fuel, could qualify for LCFS credits and RFS through Renewable Identification Number (RIN) credits. Using the estimated use of RNG of 1,815 MCF/year from the MPT community, the excess RNG for use in the transportation sector would be 35,930-38,230 MCF/year. Based on the 2018 average LCFS credit value of $160 per metric ton (MT), the LCFS value per MSCF would be $62.37. This equates to over $2.2 million dollars a year in LCFS credits. Similarly, RIN credits at $1.45/RIN would be $661,876 annually. Leveraging these credits alone would yield a simple payback of less than three years. Figure 5 shows estimated LCFS and RIN credits that could be earned based on historical averages.

Leveraging the grant programs along with the LCFS and RIN credits, the project could have a payback of two to three years. The economics of the cost verses funding and revenue opportunities make this a solid option for providing natural gas to the nearby MPT community.

FIGURE 5

Estimated LCFS and RIN Credits for RNG

Parameter	Units	Value
# of Milking Cows	Cow	1,500
Estimated Annual RNG production[12]	MCF/yr	37,200
Monterey Park Tract Annual Consumption mscf[13]	MCF/yr	1815
Amount of RNG for Dairy Usage[14]	MCF/yr	6,657
Amount of RNG to be transported for vehicle fuel	MCF/yr	28,728
# of CNG Tube Trailer Transports Per Year	Tube	89
LCFS Credit Price per Metric Ton Co2[15]	Dollar/MT CO2	$160.00
Transported Volume per RNG Tube Trailer	MCF	324
Estimated MPT CNG Station Usage at Dairy	MCF/yr	3650
Estimated Carbon Intensity Score[16]	gCO2e/MJ	-276.24
LCFS Value per MSCF[17]	Dollar/MCF	$62.37
Carbon Benefit Compared[18]	CO2e/mmbtu	0.39
Annual LCFS Credits Per Year Vehicle Usage		**$2,206,956.70**
Federal RIN D Code 3 Credit Price[19]		$1.45
Federal Rin Production		35385
RIN per mmbtu	Credit/mmbtu	12.9
Annual Federal Rin Credits		**$661,876**
Total Annual Credits		**$2,868,833**

Consult with TID and CEC

Over the past few months, PG&E has met with both TID and the CEC to discuss the potential for electrification at MPT and to consult on Gas R&D programs. Both organizations were appreciative of the conversations and interested in continuing to discuss potential options that could benefit the community and advance innovative clean-energy solutions. Discussions remain at a high level, at this time, but all parties are open to continuing conversations as more work and analysis is completed.

[12] Based on B&V winter scenario.

[13] Estimated use based on similar sized homes 5 miles away in Ceres, CA in PG&E gas service territory.

[14] Based on estimated Dairy Annual Diesel Usage gallons.

[15] 2018 average price per LCFS credit.

[16] Estimated Carbon Intensity Score of the Dairy Biogas to CNG pathway was calculated to be -276.24 gCO2e/MJ in the California Air Transportation Board *Staff Summary Method 2B Application: Prospective Pathway Dairy Biogas to CNG, California Bioenergy LLC ("CalBio") Bakersfield, CA* : https://www.arb.ca.gov/fuels/lcfs/2a2b/apps/calbio-sum-122115.pdf.

[17] Based on CARB LCFS Credit Calculator v. 1.3 assuming a price of $160/MT CO2e.

[18] Based on CARB LCFS Credit Calculator v. 1.3.

[19] Historical prices vary and are available at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information.

Learnings from TID

PG&E has continued conversations with TID since initial outreach with TID staff in 2018 when PG&E was developing our RNG pilot proposal, and consistent with D.18-12-015, those recent conversations have focused on the possibility of a TID electrification option in MPT. In a conversation on April 18, 2019, TID expressed interest in electrification options that could benefit the MPT community. TID's current outreach efforts are occurring in the community to survey households and provide immediate energy cost relief using current TID programs, including weatherization and low-income assistance. Outreach has resulted in a limited response so far, but data gathering from this near-term outreach is intended to inform future efforts being considered. Overall projected costs remain challenging to TID, as costs would be spread over a limited number of customers, but TID is still interested in seeing if any savings can be realized from a future electrification program.

Learnings from CEC

Consistent with the guidance in D.18-12-015, PG&E has met with various sectors of the CEC[20] to consult their expertise in both the RNG and possible electrification options being considered for the community. In the initial conversations, PG&E met with CEC teams focused on electrification and gas R&D programs separately due to the distinct differences in the areas of expertise and focus. Both teams were interested in our proposal and CEC staff are pulling together other CEC teams for a follow-up meeting with all the relevant sectors together to provide a more holistic and aligned approach in feedback and consultation to PG&E regarding the opportunities for MPT.

When PG&E's proposal for MPT and the ordering language from D. 18-12-015 was discussed, the CEC noted that it touched many different groups within the CEC and other organizations such as California Air Resources Board (CARB) and the LCFS team, who may have interest in exploring both the RNG proposal and opportunities with TID for electrification. Going forward, the CEC offered to provide information on CEC programs and initiatives that are aligned with our project(s) as well as further consulting support and feedback to help with the project's viability and progress being made, if the MPT community continues to be considered as a pilot community.

[20] Meetings with the CEC were held on May 29, 2019 and May 30, 2019.

PG&E Conclusion and Recommendations

PG&E finds the gas microgrid to be the best solution for serving the MPT community based on the further exploration and assessment of costs and timeline to partner with a dairy to provide RNG, and recommends it be approved. Implementing this project would provide the following benefits:

- Provide access to affordable energy options in the MPT community;
- Reduce household energy costs for participating customers;
- Increase health, safety and air quality of the MPT community and surrounding area;
- Provide additional workforce opportunities;
- Additional jobs from construction of the project and maintenance of the digester and biogas cleanup system; and
- Innovative learnings which could be applied to other communities.

Gas microgrids provide significant environmental benefits to local communities through reducing odor, and GHG emissions, improving indoor and outdoor air quality and safety.

From the B&V report PG&E concludes the following:

- PG&E's MPT proposal is a viable project and the preliminary Project schedule shows a duration of 22 months from NTP to Commercial Operation Date, with the possibility of additional time being needed for preliminary engineering or California Environmental Quality Act.
- The capital cost for the Project is expected to be around $7.2 million – $9.8 million, depending on the project delivery approach, and B&V recommends the third-party developer approach to greatly reduce capital costs.
- The O&M costs for the Project are expected to be around $515,000 per year, not including tube trailer transportation.
- Production of RNG using a lagoon digester, membrane-based biogas cleaning system, and on-site CNG refueling station is technically feasible at the scale of interest investigated by B&V and can be reproduced in similarly situated communities.
- Based on the conceptual design for a lagoon digester and RNG production facility at Trinkler, manure from 1,500 milking cows (as well as from 1,380 other cows housed on-site) could produce 37,200 to 39,500 MCF/year of RNG. This is significantly more than what is needed to serve the MPT community estimated usage of 1815 MCF/year and would have broader benefits in the surrounding area with the use of RNG for transportation.
- Beyond the scope of the Phase 2 MPT Gas Microgrid Project, an additional opportunity and potential alternative for MPT would be a pilot program to explore the future use of hydrogen as an energy carrier in domestic applications.

From the GNA report PG&E concludes the following:

- The infrastructure development incentives for the dairy digester and alternative fuel vehicles along with the LCFS and RIN credits make this a viable project with a very attractive economic outlook.

- It would be prudent for Trinkler/developer to apply for all incentive programs that the project is eligible for to help fund the installation of the anerobic digester, biogas cleanup system, and CNG refueling infrastructure.
- Selling the surplus RNG for use an alternative vehicle fuel is critical to achieving the full benefits of installing the dairy digester at the dairy. Trinkler and the surrounding community would greatly benefit from the introduction of a CNG fueling station if they leveraged the various incentives available for CNG vehicles.
- The utilization of LCFS and RIN credits when the RNG is used for the transportation sector could significantly off-set the cost of the installation, O&M of the dairy digester, biogas cleaning system, and CNG refueling equipment.

Based on the findings from B&V and GNA, it is clearly evident that the list of incentives and credits make the installation of the dairy digester, biogas clean-up system and CNG refueling system a viable financial investment. The $7.21 million – $9.76 million costs could have a payback of less than 3 years.

Additionally, the CEC was supportive of providing consultation to ensure the project provides valuable R&D opportunities that could go above and beyond the SJV DAC objectives. PG&E recommends that the Commission approve the MPT Gas Microgrid pilot to test the concept of using the production of RNG from dairy manure for localized gas distribution networks and transportation applications.

PG&E thanks the Commission for considering this proposal as a gas pilot for the SJV DAC proceeding and looks forward to working with the Commission and other stakeholders on next steps.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A

BLACK & VEATCH REPORT

FINAL – PUBLIC

MONTEREY PARK TRACT GAS MICROGRID RNG DESIGN REPORT

B&V PROJECT NO. 401616
B&V FILE NO. 40.8100

PREPARED FOR

Pacific Gas & Electric Company

7 JUNE 2019

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Project Identification	
Title:	PG&E Monterey Park Tract Gas Microgrid
Address:	Ceres, CA
Document:	Monterey Park Tract Gas Microgrid RNG Design Report
Issue Status:	**Final Issue**
Certification(s)	*Applicable only to sections of document that are not noted as being outside of Black & Veatch's scope*

I hereby certify that this document was prepared by me or under my direct supervision and that I am a duly registered professional engineer under the laws of the state of California:	I hereby certify that this document was prepared by me or under my direct supervision and that I am a duly registered professional engineer under the laws of the state of California:	I hereby certify that this document was prepared by me or under my direct supervision and that I am a duly registered professional engineer under the laws of the state of California:
Mechanical Engineering	***Electrical Engineering***	***Civil Engineering***
LICENSED PROFESSIONAL ENGINEER MICHAEL CRAIG HUMS M38483 MECHANICAL STATE OF CALIFORNIA	REGISTERED PROFESSIONAL ENGINEER THOMAS A. HOKE No. E 16538 Exp. 31 DEC 2019 ELECTRICAL STATE OF CALIFORNIA	REGISTERED PROFESSIONAL ENGINEER CAMERON L. BRYANT C63061 Exp. 30/JUNE/2020 CIVIL STATE OF CALIFORNIA
6/6/19	06 JUN 19	07/JUNE/2019
Signed: Michael Craig Hums	Signed: Thomas A. Hoke	Signed: Cameron L. Bryant
Date: June 06, 2019	Date: June 06, 2019	Date: June 06, 2019
Registration No.: M38483	Registration No.: E16538	Registration No.: C63061

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

Black & Veatch has provided conceptual engineering support to Pacific Gas & Electric (PG&E), who is interested in demonstrating a localized gas distribution network using locally-sourced renewable natural gas (RNG). This support included a site visit to a dairy partner's site (as a prospective location for RNG production via anaerobic digestion of dairy manure), establishing a conceptual design basis for the RNG production and distribution operation, preparation of conceptual engineering documentation, conducting a preliminary environmental site assessment, developing capital and operations and maintenance (O&M) cost estimates, and opining on the future potential for renewable hydrogen utilization as part of the "gas microgrid." The gas microgrid project is currently being evaluated by PG&E as part of a proposal submitted to the California Public Utilities Commission (CPUC) to support CPUC's interest in exploring the economic feasibility of various options to bring affordable energy to residents of disadvantaged communities in the San Joaquin Valley in California.

Monterey Park Tract (MPT) is a disadvantaged community (DAC) in San Joaquin Valley (SJV) that is being considered to host the gas microgrid. MPT does not have natural gas and relies on propane fuel for residential uses. As part of the first phase of the program, PG&E would construct and operate the localized gas distribution network at MPT and source fossil-based natural gas from a pipeline interconnection via tube trailer deliveries. The envisioned second phase of the program would include the construction and operation of a dairy manure anaerobic digestion (AD) system at the nearby Trinkler Dairy, located in Ceres, California. The biogas produced from the AD process would then be captured and cleaned to pipeline quality standards, after which the resultant RNG would be piped to MPT, used locally for vehicle refueling, and transported via tube trailer for use at other natural gas refueling stations.

Black & Veatch prepared a design basis memorandum and conducted a site visit to Trinkler Dairy to establish the premise upon which a conceptual design was prepared. A covered lagoon AD system and membrane-based biogas cleaning system were selected for consideration. Manure amounts for summer and winter months were then quantified, after which mass and energy balances were prepared. An RNG production rate of 37,200 to 39,500 thousand cubic feet per year were predicted from this analysis. Engineering documentation, including preliminary process flow diagrams, equipment lists, and site plans, were developed and issued to prospective bidders to obtain budgetary quotes for the digester, biogas cleaning, and refueling subsystems. Based on responses from vendors, Black & Veatch updated engineering documentation and prepared an electrical one-line diagram and load list.

The preliminary environmental site assessment indicated that the project may avoid a lengthy permitting process by requesting a modification to the current dairy farm's Use Permit to include the RNG production and distribution facility. A permitting period of 12 to 15 months is considered likely to obtain the required permits for most biogas upgrading projects within the SJV jurisdiction. Based on the conceptual engineering design package and expected permitting requirements, Black & Veatch developed a schedule that showed a 22-month duration to implement the project including permitting, engineering, procurement, construction, and commissioning. A capital cost estimate range of $7,209,000 to $9,761,000 was forecast for the project with the expectation that a developer-led execution approach would likely result in lower costs than a third-party integrator execution approach. O&M costs for the project were estimated to be approximately $515,000 per year.

Given the increased focus on hydrogen as an environmentally-friendly energy carrier, Black & Veatch reviewed the principal hydrogen production, distribution, and utilization considerations with a focus on the potential insights that a gas microgrid could offer, if some or all of the gas was converted to hydrogen. It was found that MPT, if selected as the beneficiary for the proposed gas microgrid, would serve as an ideal pilot program to study the benefits of hydrogen utilization for domestic applications. Blending of hydrogen with RNG or producing hydrogen from RNG could both be accomplished as an extension of the MPT Gas Microgrid, further adding value to the project as proposed.

1.0 Introduction

1.1 PROGRAM BACKGROUND

PG&E is interested in demonstrating a localized gas distribution network served by PG&E's portable gas service in the MPT DAC of the SJV region of California using locally-sourced RNG. As part of this program, PG&E submitted a proposal to the CPUC in January 2018. Based on the feedback and requested modifications from the CPUC, PG&E modified their offering and submitted an amended proposal in October 2018. In December 2018, the CPUC issued a decision (Rulemaking 15-03-010) to approve various pilot programs, which directed PG&E to refine the costs and projected benefits contained in their amended proposal for the MPT Gas Microgrid Program.

Phase 1 of the MPT Gas Microgrid Program involves the design, construction, and operation of a local gas distribution network with hub to serve the MPT community via a "virtual" pipeline using tube trailers to deliver fossil-based natural gas. Phase 2 involves the design, construction, and implementation of the infrastructure needed to service the MPT gas microgrid with a supply of locally-sourced RNG derived from the AD of dairy manure as well as a refueling station. Black & Veatch was retained by PG&E to provide conceptual engineering and cost estimation services to refine the amended proposal to the CPUC, known herein as the "Project."

1.2 PHASE 2 BUSINESS CASE REVIEW

As part of this Project, Black & Veatch performed an initial review of the business case developed by PG&E. The purpose of this business case review was to clarify the assumptions that went into the initial business case and adjust these assumptions based on the recent work performed by Black & Veatch.

1.2.1 Technical Details

The major subsystems encompassed in the Phase 2 MPT Gas Microgrid would include:

- Dairy manure collection, pre-treatment, and AD.
- Biogas upgrading.
- Point of receipt (POR) station.
- MPT microgrid distribution (installed in Phase 1).
- Compressed natural gas (CNG) refueling.
- CNG tube trailers and pipeline interconnection.

PG&E envisions that the selected farm, Trinkler Dairy in Ceres, California, or other third party would own/operate the dairy manure collection, pre-treatment, AD, and biogas upgrading system. PG&E originally assumed that Trinkler included 1,500 milking cows that could produce RNG at a rate of 28 standard cubic feet (scf) per cow per day, which corresponds to a scrape-type manure collection system. This results in a total estimated RNG production rate of 15,330 thousand cubic feet (MCF) per year (yr).

Black & Veatch surmised that PG&E would own/operate the POR station, on-site CNG refueling, CNG delivery trucks/tube trailers, and interconnections. It was assumed that RNG would be distributed to the MPT community via a metered pipeline after Phase 2 was fully implemented. PG&E further assumed that the balance of RNG produced not used for MPT or on-site refueling would be transported off-site via tube trailers and injected into the same fossil-based transmission pipeline interconnection used to supply MPT in Phase 1. These stations would be owned/operated by third-party project participants and allow for additional RNG sales into the transportation market. Table 1-1 summarizes the technical details for the Phase 2 MPT Gas Microgrid.

Table 1-1 MPT Gas Microgrid Phase 2 Technical Details

PARAMETER	UNITS	VALUE
MPT RNG Consumption	MCF/yr	1,270
Trinkler Dairy Diesel Fuel Consumption	Gallon/yr	185,000
Trinkler Dairy Diesel to RNG Conversion	%	25
Trinkler Dairy RNG Consumption	MCF/yr	6,657
RNG for Pipeline Injection via Tube Trailer	MCF/yr	7,403
Tube Trailer Capacity	MCF/trailer	324
Annual Tube Trailer Trips	#	23
Total RNG Production	**MCF/yr**	**15,330**

1.2.2 Financial Details

Renewable fuel transportation credit inputs used by PG&E include the California Low Carbon Fuel Standard (LCFS) with a pathway carbon intensity (CI) score of -276.24 grams of carbon dioxide equivalent per megajoule and LCFS credit price of $160 per metric ton. At this CI score and credit price, the resultant LCFS value would be $62.37/MCF. Presently, PG&E does not include Federal Renewable Fuel Standard (RFS) Renewable Identification Number (RIN) credits as part of their business case for the Project. However, potential revenues from RIN generation were estimated assuming $1.45/RIN.

Table 1-2 shows the capital costs for the Phase 1 and Phase 2 MPT Gas Microgrid major project elements, estimated by PG&E and reflected in United States (US) dollars (USD). The differences in gas microgrid capital costs between the two phases included land costs, microgrid enclosures, microgrid fencing, and microgrid pad/site improvements.

Table 1-2 MPT Gas Microgrid Phase 2 Capital Costs

PARAMETER	UNITS	VALUE
Phase 1 MPT Gas Microgrid Capital Cost	USD	$3,843,482
Phase 2 MPT Gas Microgrid Capital Cost [1]	USD	$4,115,282
Behind the Meter Costs	USD	$1,110,233
Other Microgrid Costs	USD	$3,005,049
Phase 2 RNG Production Capital Cost [2]	USD	$2,324,530
Biogas Cleaning System	USD	$620,000
Refueling System	USD	$460,000

[1] These costs would be in addition to the RNG Production Capital Cost estimate provided by Black & Veatch in Section 4.2 as part of the SJV DAC proceeding and not the responsibility of the dairy owner.
[2] These costs exclude digester cost and will be updated by Black & Veatch in Section 4.2.

PARAMETER	UNITS	VALUE
Other Direct Costs	USD	$1,244,530

1.3 OBJECTIVES

The primary objective of this project is to develop conceptual engineering designs and associated capital and O&M cost estimates for RNG production (and delivery) facilities at a local dairy farm, which can serve the MPT community (Phase 2 of the MPT Gas Microgrid Project). In order to develop these cost estimates, the following tasks have been undertaken:

- Conduct a site visit to Trinkler Dairy to confirm assumptions that would inform the conceptual design basis, environmental/permitting review, and revised business case.
- Establish a conceptual design basis for the RNG production and distribution operation.
- Produce conceptual engineering documentation, including mass and energy balance, process flow diagram (PFD), equipment list, site plan, and electrical load list/one-line diagram.
- Prepare a preliminary environmental site assessment, including preliminary permitting matrix.
- Formulate a project schedule.
- Develop engineering procurement construction (EPC) capital and O&M cost estimates based on the conceptual design.
- Opine on the future potential for renewable hydrogen utilization as part of a gas microgrid.
- Compile the technical and economic findings into a report.

1.4 REPORT ORGANIZATION

Many of the engineering deliverables are included in the appendices of this report with a brief narrative included in the body of the report. Acronyms used throughout the document are included in Appendix A. This report is organized into the following sections:

- Section 2.0 – Engineering.
- Section 3.0 – Project Schedule and Cost Estimates.
- Section 4.0 – Environmental Site Assessment.
- Section 5.0 – Future Hydrogen Utilization.
- Section 6.0 – Conclusions and Recommendations.
- Section 7.0 – References.

2.0 Engineering

2.1 DESIGN BASIS

A Design Basis Memorandum was prepared to define the basis used in engineering/design activities for the MPT Gas Microgrid Project and is attached in Appendix B.

2.1.1 Site Information

Site-specific design criteria were developed using local weather data. It was assumed that existing water sources (i.e. recycled water from wastewater storage lagoons (WWSLs), well water, and irrigation canal) would continue to be used for barn manure flushing, parlor manure flushing, and fire water. The Trinkler Dairy site is located approximately eight miles south of Modesto in the town of Ceres, CA, which is in the SJV. The site address is 7251 Crows Landing Rd. and is located between W. Taylor Rd. to the north and W. Zeering Rd to the south. Major transportation links in the vicinity include California Route 99 to the east and California Route 33/Interstate 5 to the west. Additional site information is detailed in a site visit memorandum included in Appendix C.

2.1.2 Process Design Basis

Table 2-1 and Table 2-2 show the feedstock design basis for Summer and Winter cases, respectively. According to Trinkler Dairy, the capture of milking cow manure is lower in summer and higher in winter, the difference for which is highlighted in red in each table.

Table 2-1 Manure Feedstock Design Basis (Summer)

PARAMETER	UNIT	MILKING COWS	DRY COWS	HEIFERS	CALVES	TOTAL
Count	#	1,500	305	745	330	2,880
Moisture	Wt%	87%	87%	83%	83%	85.51%
Total Solids (TS)	Wt%	13.30%	13.30%	17.10%	16.80%	14.68%
Volatile Solids (VS)	Wt% of TS	85.00%	83.60%	86.60%	86.60%	85.45%
Nitrogen	Wt%	0.66%	0.60%	0.54%	0.74%	0.63%
Phosphorus	Wt%	0.11%	0.08%	0.09%	0.09%	0.10%
Total Manure	lb/day-animal	150	83	48	48	104.83
Total Manure	ft^3/day-animal	2.4	1.3	0.78	0.78	1.68
Density	lb/ft^3	62.5	63.8	61.5	61.5	62.28
Capture	%	75%	70%	70%	100%	76%
Mass Flow	lb/day	168,750	17,721	25,032	15,840	227,343
Volume Flow	ft^3/day	2,700	278	407	257	3,642

Table 2-2 Manure Feedstock Design Basis (Winter)

PARAMETER	UNIT	MILKING COWS	DRY COWS	HEIFERS	CALVES	TOTAL
Count	#	1,500	305	745	330	2,880
Moisture	Wt%	87%	87%	83%	83%	85.51%
TS	Wt%	13.30%	13.30%	17.10%	16.80%	14.68%
VS	Wt% of TS	85.00%	83.60%	86.60%	86.60%	85.45%
Nitrogen	Wt%	0.66%	0.60%	0.54%	0.74%	0.63%
Phosphorus	Wt%	0.11%	0.08%	0.09%	0.09%	0.10%
Total Manure	lb/day-animal	150	83	48	48	104.83
Total Manure	ft^3/day-animal	2.4	1.3	0.78	0.78	1.68
Density	lb/ft^3	62.5	63.8	61.5	61.5	62.28
Capture	%	100%	70%	70%	100%	89%
Mass Flow	lb/day	225,000	17,721	25,032	15,840	283,593
Volume Flow	ft^3/day	3,600	278	407	257	4,542

Table 2-3 shows the design basis assumptions for raw biogas, dry biogas, off-gas, and RNG.

Table 2-3 Biogas, Off-Gas, and RNG Design Basis

PARAMETER	UNIT	RAW BIOGAS	DRY BIOGAS	OFF-GAS	RNG
Methane	Vol%	65.00%	65.52%	9.26%	96.04%
Carbon Dioxide	Vol%	31.80%	32.06%	88.92%	0.91%
Nitrogen	Vol%	1.90%	1.92%	0%	2.96%
Oxygen	Vol%	0.50%	0.50%	1.25%	0.09%
Water	Vol%	0.60%	0%	0%	≤ 7 lb/MMscf
Hydrogen Sulfide	Vol%	0.20%	0%	0.57%	<4 ppm_v
Total Sulfur	ppm_v	-	-	-	<17 ppm_v
Siloxanes	Mg/Nm^3	-	-	-	0.1
Temperature	°F	-	-	-	60 ≤ T ≤ 100
Dew Point	°F	-	-	-	≤ 45

2.1.3 Process Design Criteria

Black & Veatch selected a covered lagoon digester for this project based on the fact that Trinkler Dairy currently utilizes a flush-type manure collection system and the popularity of such digesters throughout California. Covered lagoon digesters typically include minimal pretreatment and conditioning of digester influent (i.e. oversized particle or bedding separation) and are unheated. Digestate from the process is typically pumped into a storage lagoon and used as an agricultural fertilizer. Additional AD design criteria are displayed in Table 2-4.

Table 2-4 Anaerobic Digestion Design Criteria

PARAMETER	UNITS	VALUE
Total Solids for Digester Influent	Wt%	<2%
Hydraulic Retention Time	days	55
Organic Loading Rate	lb-VS/1,000-ft^3/day	10-11
Specific Biogas Yield per Unit Influent	ft^3/lb-VS	6-8
Specific Biogas Yield per Unit VS Consumed	ft^3/lb-VS	14-18

PG&E selected a membrane-based biogas cleaning system for this project, which was confirmed to be reasonable by Black & Veatch. It is expected that the system will require upstream capture of hydrogen sulfide using adsorbents to protect downstream process equipment, maintain safety, and meet environmental requirements. The biogas cleaning system will need to include removal of moisture and filtration for particulates but is not expected to require removal of volatile organic compounds (VOCs) and siloxanes.

2.1.4 Discipline-Specific Design Criteria

The Design Basis Memorandum provides several sections focused on engineering discipline-specific design criteria. The Civil/Structural criteria include environmental, design loads, architecture, concrete, steel structures, site, and foundations. The Mechanical criteria include piping, components, accessories, valves, coatings, freeze protection/temperature maintenance, space conditioning, and fire protection. The Electrical criteria include available power, electric motors, emergency systems, hazardous area classification, grounding, lightning protection, lighting, wiring, raceways, plant communications, and freeze protection/temperature maintenance.

2.1.5 Safety Considerations

The use of AD for manure management has a host of environmental benefits compared with typical management practices, but also presents a new set of safety considerations that must be properly managed. The production of biogas via AD results in a number of health and safety risks, including fire/explosion, asphyxiation, toxicity concerns with certain contaminants (i.e. hydrogen sulfide and ammonia), gas/liquid leaks, and biological hazards (i.e. pathogens). Some of these risks exist for a typical manure management system, while others are introduced solely due to the presence of biogas. Proper plant design, construction, commissioning, and operator training is required to minimize the likelihood of incidents occurring as a result of these risks.

2.2 MASS AND ENERGY BALANCE

Black & Veatch prepared a mass and energy balance for the Phase 2 MPT Gas Microgrid Project, which is attached in Appendix D. This analysis covers all process flows (21 total streams) from manure and recycled water inputs to the digester to RNG outputs for various end uses. In instances where information was not immediately available from Trinkler Dairy, Black & Veatch used relevant literature sources to approximate stream characteristics (Summers Consulting LLC, 2013).

The mass balance was primarily compiled using the design basis assumptions and process stream characteristics outlined in Section 2.1.2. A summary of the major elements of the mass and energy balance is shown in Table 2-5.

Table 2-5 Mass and Energy Balance Summary

PARAMETER	UNITS	SUMMER	WINTER
Combined Flow from Barns	lb/hr	110,091	134,700
Influent to Digester	lb/hr	107,130	131,078
Raw Biogas Production	scfm	122.3	115.1
RNG to MPT	scfm	2.5	2.5
RNG to Local Refueling	scfm	13.3	13.3
RNG to Tube Trailers	scfm	63.4	58.7
Total RNG [3]	**MCF/yr**	**39,500**	**37,200**

2.3 PROCESS FLOW DIAGRAM

The PFD for the Phase 2 MPT Gas Microgrid Project is included in Appendix E. Major subsystems are broken up by drawing number. Drawing 0100 depicts the digester and shows how existing manure management equipment and WWSLs would interface with the new equipment associated with the AD process. Drawing 0200 shows the biogas cleaning process with the exception of the final RNG compressor. Drawing 0300 includes all RNG handling and distribution equipment, including the refueling station and pipeline to MPT. Drawing 0400 displays the thermal oxidizer system, which is assumed to also serve as a flare when the biogas cleaning system is nonoperational. All numbered streams included in the PFD correspond to the same streams from the mass and energy balance.

2.4 EQUIPMENT LIST

The Phase 2 MPT Gas Microgrid Project equipment list is attached in Appendix F and includes all equipment reflected in the PFDs organized by type and tag number.

2.5 SITE PLAN

The Phase 2 MPT Gas Microgrid Project site plan consists of a general arrangement (GA) drawing (included in Appendix G) for the Trinkler Dairy site showing the major modifications anticipated and new equipment installations/site work planned.

2.6 ELECTRICAL LOADS AND ONE-LINE DIAGRAM

A summary of the electrical load list by major electrical equipment is provided in Table 2-6. Total electric power, given in kilovolt-amperes (kVA) and kilowatts (kW), is reported for each major system. Considering duty cycles, the total required electrical loads are estimated to be

[3] These values represent the minimum and maximum annual RNG production rates based on Summer versus Winter digester influent and performance parameters, actual annual production will be in between these values.

approximately 247 kW or 2,056,000 kilowatt-hours per year. The electrical one-line diagram corresponding to these loads is included in Appendix H.

Table 2-6 Summary of Electrical Load List

MAJOR EQUIPMENT NAME	ELECTRICAL LOADS *kVA*	ELECTRICAL LOADS *kW*
Rain Water Sump Pump	2.74	3.23
Fire Water Pump	0.00	0.00
Digester Gas Feed Compressor	43.23	50.86
RNG Compressor & Cooler	92.28	108.57
Flare Compressor	6.32	7.43
Flare Fan	1.75	2.05
Miscellaneous	63.00	74.12
TOTAL	**209.32**	**246.26**

3.0 Environmental Site Assessment

The construction and operation of an RNG production and distribution facility located at the Trinkler Dairy Farm in Stanislaus County, California, must adhere to relevant environmental and air quality regulations, as administered by the appropriate federal, state and local regulatory authorities having jurisdiction including the San Joaquin Valley Air Pollution Control District (SJVAPCD), the Central Valley Regional Water Quality Control Board (RWQCB) and Stanislaus County. Under these regulations, a facility that has the potential to impact the local environment or emit regulated pollutants must limit these environmental impacts and emissions to permitted levels. This section provides an overview of the relevant environmental and air quality permitting processes that may apply to the development of an RNG production and distribution facility at the Trinkler Dairy Farm. Black & Veatch also developed a table of potential permits and approvals that may be required for an RNG production and distribution facility located in Stanislaus County. The full table is provided in Appendix I, Table I-1.

3.1 PERMITS FOR EXISTING DAIRY FARM

Trinkler Dairy Farm, the planned location for the RNG production and distribution facility, is currently operating under Permits to Operate N-6208-1-2, -2-2, -3-2, -4-2, and -7-1 as issued by the SJVAPCD. The facility requested Authority to Construct (ATC) permits for an expansion of the existing dairy operation and approval was issued on September 12, 2017. At this time, construction for an expansion has not yet begun. Black & Veatch notes that if construction does not commence within two years from the date of issuance of the approvals, the ATCs shall expire. Per Rule 2050, an ATC can be renewed for one additional two-year period if certain conditions are met. [4]

Trinkler Dairy Farm operates under the RWQCB Trinkler Dairy Farm currently has coverage under RWQCB General Order for Existing Milk Cow Dairies Order No. R5-2013-0122 and is in good standing with the RWQCB. Trinkler Dairy Farm has prepared a Nutrient Management Plan and Waste Management Plan for the planned expansion. However, if the RNG production and distribution facility is located on the Trinkler Dairy Farm then they would need to obtain coverage under the RWQCB Order No. R5-2010-0130 Waste Discharge Regulatory Program for Dairy Manure Digester and Co-Digester Facilities.

The Trinkler Dairy Farm has also been approved for a Use Permit from Stanislaus County for the planned expansion but as noted above, construction work for the planned expansion has not yet begun. In its review process Stanislaus County was the lead California Environmental Quality Act (CEQA) agency for the application. The expansion received a Negative Declaration for the project, which means it was found the project would not have a significant effect on the environment. Under Stanislaus County Zoning Ordinance, the inclusion of an RNG production and distribution facility at the site would require a Use Permit and would be subject to a CEQA Review. It is likely that the project would receive a similar Negative Declaration.

3.2 SELECTED PERMITTING ACTIVITIES

The majority of the permits and approvals identified in Appendix I, Table I-1 require a review and approval time of less than 3 to 6 months. In some cases, only notification to the relevant regulatory

[4] Per Rule 4050, the following three scenarios may warrant the agency granting an extension: The Air Pollution Control Officer (APCO) finds the applicant cannot commence construction because all necessary preconstruction approvals or permits have not been obtained, the APCO finds the facility has experienced an economic downturn, or the ATC is part of a larger project which has commenced construction.

authority is required. However, depending upon facility design and operational parameters, there are some permitting activities that may require 6 to 18 months for review and approval.

Depending on the final design and operational parameters, some requirements of certain permits may be eliminated, or the review time required for permit review may be minimized. With respect to specific permitting activities, Black & Veatch notes the following:

- **US Army Corp of Engineers (USACE) Section 404 Permit and RWQCB 401 Water Quality Certification:** It is assumed that the planned RNG production and distribution facility located at the Trinkler Dairy Farm will be sited to avoid construction near waterways or wetlands. Therefore, it is considered unlikely that the installation of the planned project would require a Section 404 permit or a RWQCB Section 401 Water Quality Certification.
- **CEQA Review:** CEQA review is triggered by the development and use of new lands within the state of California. Since the RNG production and distribution facility will be located at an existing dairy farm and is installed completely within the boundaries of the existing farm, there is a possibility that a CEQA review may not be required. However, according to the Stanislaus County Zoning Ordinance, there is potential that the RNG production and distribution facility would require a Use Permit and undergo a CEQA Review in the process of obtaining that permit. Stanislaus County should be consulted once design and operational parameters are final to confirm whether CEQA review would apply to the project or is not required.
- **Central Valley Regional Water Quality Control Boards National Pollution Discharge Elimination System (NPDES) Discharge Permit:** The RNG production and distribution facility will require the existing Trinkler Dairy Farm NPDES to be modified. The addition of the RNG production and distribution facility would qualify Trinkler Dairy Farm for the RWQCB Order No. R5-2010-0130 Waste Discharge Regulatory Program for Dairy Manure Digester and Co-Digester Facilities. As mentioned in Section 1.1, Trinkler Dairy Farm currently has coverage under RWQCB General Order for Existing Milk Cow Dairies Order No. R5-2013-0122.
- **SJVAPCD ATC Permit (i.e. air permits):** An ATC will be required for each new emission source included in the facility design prior to construction. It is likely that the emission sources associated with the RNG production and distribution facility will be regulated separately from the existing dairy farm (i.e. permitted as a separate facility) due to the facilities falling under different Standard Industrial Classification (SIC) codes and potentially being run by different operators. The bullets below and the permit matrix in Table F-1 provide additional information related to air permitting.
    - If the project exceeds the Best Available Control Technology (BACT) threshold but stays below the New Source Review (NSR) major source thresholds (listed in Table I-1), minor source BACT would apply. In the SJVAPCD, minor source BACT is typically the most stringent emission limit or control technology that is achieved in practice, but economic feasibility is considered. Potential BACT for the thermal oxidizer is also listed in Table I-1. [5]
    - Exceeding the NSR major source thresholds results in additional time and potentially costly analyses/requirements to obtain construction approval, including securing emissions offsets. Lowest Achievable Emission Rate (LAER) technology is

[5] The thermal oxidizer may not be subject to BACT because it may be classified as an emissions control device.

required for NSR major sources. While BACT in California is often considered as stringent as federal LAER, LAER in California is associated with the most stringent emission limit or emission control achieved in practice.

- Emissions offsets are required for emissions increases of 10 tons per year (tpy) of nitrogen oxides (NO_X) and/or VOCs for projects under the SJVAPCD's authority. Purchasing emissions offsets in California can represent a significant cost to the project. In addition, the availability of offsets can be limited in this region of the state.
- If the facility's potential emissions render it applicable as a Title V major source, a Title V operating permit will be required. These operating permits contain monitoring, recordkeeping and reporting requirements that are often more involved than operating permits for minor sources.
- SJVAPCD Rule 4311: Rule 4311 regulates NO_X, VOCs and sulfur oxides (SO_X) emissions from flares installed within the jurisdiction of SJVAPCD. This rule only applies to flares with the potential to emit 10 tpy or more of NO_X and/or VOCs. The rule includes NO_X and VOCs emission limits that vary depending on flare size and design, as displayed in Table 3-1. Source testing, monitoring, recordkeeping and reporting requirements are also included in the rule and may be applicable to the thermal oxidizer being considered for this project.

Table 3-1 Emission Standards for Ground-Level Enclosed Flares [6]

TYPE OF FLARE AND HEAT RELEASE RATE	VOCs *lb/MMBTU* [7]	NO_X *lb/MMBTU*
Without Steam-Assist		
< 10 MMBTU/hr	0.0051	0.0952
10 – 100 MMBTU/hr	0.0027	0.1330
> 100 MMBTU/hr	0.0013	0.5240
With Steam-Assist		
All	0.14 (as Total Organic Gases) [8]	0.068

- **SJVAPCD Rule 4570:** Trinkler Dairy Farm is currently subject to Rule 4570 which regulates VOC emissions from Confined Animal Facilities. With the installation of an anaerobic digester, the facility will be required to keep records of design specifications and maintenance logs demonstrating that compliance with Natural Resources Conservation

[6] Flares that are permitted to operate only during an emergency are not subject to the emission standards in this table.

[7] Million British Thermal Units (MMBTU)

[8] All hydrocarbon compounds containing hydrogen and carbon with or without other chemical elements.

Service Field Office Technical Guide Code 366 or 365 is met. The dairy farm will continue to be required to implement mitigation measures as contained in this rule.

- **SJVAPCD Rules 4621 – 4624:** Rules 4621 – 4624 regulate VOC emissions from storage and transfer of organic liquids and gasoline. Depending on the final design of the project, some of these rules may not apply and applicability will need to be revisited. Overall, these rules contain VOC control system requirements, leak inspection requirements, recordkeeping, and testing requirements.

3.3 CONCLUSIONS REGARDING PERMITTING

Permitting of the RNG production and distribution facility, requires permit approvals from multiple regulatory agencies. It is recommended that project developers engage regulatory agencies as early as possible in the development process to identify which permits are required and to determine the length of time needed to acquire all required project permits. Additional conclusions regarding permitting of include the following:

- Since the project site already has a recent CEQA approval the project may avoid a lengthy CEQA permitting process by requesting a modification to the current Use Permit to include an RNG production and distribution facility. If the project is deemed too large for a Use Permit modification then the project may be required to apply for a new Use Permit and a the full CEQA review process, which may require a period of up to 18 months.
- It is possible the project will require installation of equipment that qualifies as BACT. Potential BACT for the thermal oxidizer is included in Table I-1.
- Emissions offsets and air dispersion modeling may be required for this project. The thresholds for triggering these requirements are included in Table I-1.
- If possible, it is advantageous to avoid major source permitting due to the typically longer permit processing times, more costly emission control requirements, and more strenuous operating permit conditions.
- A permitting period of 12 to 15 months is considered likely to obtain the required permits for most biogas upgrading projects within SJVAPCD's jurisdiction. Potential permitting activities that may require 6 to 18 months for review and approval are summarized in Table 3-2.

Table 3-2 Permitting Activities with Review Times of 6 to 18 Months

AGENCY	PERMIT/ APPROVAL	REGULATED ACTIVITY	REQUIRED PROJECT PHASE	REQUIRED FOR PROJECT	EXPECTED/ TYPICAL REVIEW TIME	COMMENTS
FEDERAL						
USACE	Section 404 Permit	Discharge of dredge or fill material into waters of the US, including jurisdictional wetlands.	Construction	Not Likely	3-6 months for nationwide permit	Unlikely that this will be required for the project based on current site selection.
STATE						
Lead Agency-Stanislaus County	CEQA Review	Land use and development in the state of California.	Construction	Yes	6-18 months	If the project may cause either a direct or indirect impact to the environment and would require the issuance of a permit by one or more public agency, it will be considered a "project" under CEQA and will be subject to review. Extent and length of CEQA review will not be known until final design and operation parameters are established.
RWQCB – Central Valley Regional Water Quality Control Board	RWQCB Order No. R5-2010-0130 Waste Discharge Regulatory Program for Dairy Manure Digester and Co-Digester Facilities	Discharge of waste water from new generation process systems.	Operation	Yes	9-12 months	Trinkler Dairy Farm will need to modify their current permit to receive coverage under this Order.

AtchA-20

AGENCY	PERMIT/ APPROVAL	REGULATED ACTIVITY	REQUIRED PROJECT PHASE	REQUIRED FOR PROJECT	EXPECTED/ TYPICAL REVIEW TIME	COMMENTS
California Environmental Protection Agency (CEPA) – State Water Resources Control Board	Water Use Permit/ Approval	Extraction and use of water.	Operation	Possible	6-12 months	The type of permit or approval will depend on the final site location and final design of the facility. Once those decisions are made, Black & Veatch can assist in determining what agency needs to issue the appropriate approval/permit.
LOCAL						
SJVAPCD	Authority to Construct	Construction of Air Contaminant Sources	Pre - Construction	Yes	Likely 6-12 months if not. Review period may exceed this timeline if the process triggers major source permitting.	BACT required for any source that causes an increase in emissions of an air contaminant greater than 2 lb/day. NSR major source permitting is triggered for projects emitting NO_X and VOCs in excess of 10 tpy, carbon monoxide (CO) in excess of 100 tpy, PM10, PM2.5 and SO_X in excess of 70 tpy. The purchase of emissions offsets is required for emissions sources with a potential to emit greater than 10 tpy for NO_X/VOCs, 27.38 tpy for SO_X, 14.6 tpy for PM_{10} & 100 tpy for CO. An ambient air quality analysis including air dispersion modeling is required for installation of any new emissions source.

AtchA-21

4.0 Project Schedule and Cost Estimates

4.1 PROJECT SCHEDULE

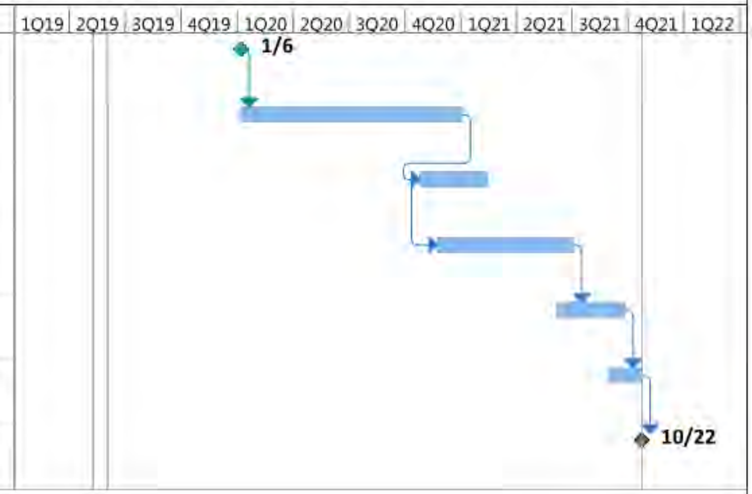
A preliminary Level 1 schedule for the Phase 2 MPT Gas Microgrid Project is shown in Figure 4-1. Key milestone dates for major events as part of the execution of this project are listed in Table 4-1 in months after notice to proceed (NTP) through commercial operation date (COD). Given the uncertainty of the execution strategy associated with this project, Black & Veatch has excluded preliminary engineering activities, which could be needed to support permit applications. It may also be possible to use the conceptual design presented herein to obtain the necessary permits. Additionally, the permitting process included in this schedule is somewhat optimistic based on the range of possibilities discussed in Section 3.0.

Table 4-1 Key Milestone Dates

PROJECT MILESTONE	DATE AFTER NTP
Permitting	12 months
Detailed Engineering	13.5 months
Procurement	18 months
Construction	21 months
Commissioning and Testing Completion	22 months
Commercial Operation Date	22 months

PG&E MPT Gas Microgrid Schedule

ID	Task Name	Duration	Start	Finish
1	NTP	0 days	Mon 1/6/20	Mon 1/6/20
2	Permitting	260 days	Mon 1/6/20	Fri 1/1/21
3	Detailed Engineering	80 days	Mon 10/26/20	Fri 2/12/21
4	Procurement	160 days	Mon 11/23/20	Fri 7/2/21
5	Construction	80 days	Mon 6/7/21	Fri 9/24/21
6	Start-Up and Commissioning	40 days	Mon 8/30/21	Fri 10/22/21
7	COD	0 days	Fri 10/22/21	Fri 10/22/21



Project: PGE MPT Gas Microgrid S
Date: Fri 5/10/19

Task
Split
Milestone
Summary
Project Summary
Inactive Task
Inactive Milestone
Inactive Summary
Manual Task
Duration-only
Manual Summary Rollup
Manual Summary
Start-only
Finish-only
External Tasks
External Milestone
Deadline
Progress
Manual Progress

Figure 4-1 Project Schedule

4.2 PROJECT COST ESTIMATES

4.2.1 Cost Estimate Basis

Black & Veatch prepared a conceptual cost estimate that is classified as an American Association of Cost Engineers Class 4 estimate with an accuracy of ±30 percent. Furnish and erect packages and equipment material prices were estimated primarily using vendor budgetary quotations for the digester, biogas cleaning, and refueling systems. The balance of equipment was estimated using in-house pricing based on historical project data. All costs are expressed in 2019 USD.

Equipment/Key Supplier List

Budgetary quotations were received for the following items based on request for quotation packages prepared by Black & Veatch and attached in Appendix J:

- Anaerobic Digester.
- Biogas Cleaning System.
- Refueling System.

The vendors selected for this project collectively have considerable experience in developing manure digestion projects in California or supplying equipment for such projects.

Civil and Structural

Concrete, rebar, and formwork quantities estimates were based on Black & Veatch internal estimates for BOP and site work. Asphalt pavement quantities were based on new roads depicted in the GA drawing and assuming a 16-inch roadway thickness.

Mechanical and Piping

Mechanical piping and equipment bill of quantities for biogas/RNG piping and fire water supply were determined on the basis of the GA drawing, applicable codes, and tie-in information provided by equipment vendors. Structures have been included for housing certain valves and pumps, as appropriate.

Electrical and Instrumentation

Cables, raceways, and other ancillary electrical supply equipment estimates were based on analogous in-house techniques. Electrical systems for the new equipment (power distribution centers, transformers, etc.) were also estimated on an analogous basis using recent in-house cost data. New instrumentation was included in vendor packages and Black & Veatch assumed that no supervisory control system would be used.

Engineering and Construction

All labor costs have been adjusted to reflect California rates and productivity. The costs reflect an engineering, procurement support, and construction management (EpCM) execution approach. Engineering has been included assuming 24 staff hours per piece of equipment for procurement specifications and 275 staff hours per piece of equipment for BOP. Similarly, construction management costs are estimated assuming 4 staff performing over a 3-month construction period. Construction indirects are estimated at 100 percent of construction labor costs.

Indirects and Exclusions

The capital cost estimate represents an overnight cost with no provisions for escalation. A contractor's contingency of 5 percent of the total installed cost (TIC) is carried. General liability and builder's all-risk insurance is estimated as a percentage of TIC. Exclusions from this cost estimate include permitting, capital spares, taxes/duties, liability insurance, letters of credit/bonds, tariff impacts, hazardous materials handling/abatement, and other Owner's costs.

Developer-Led Capital Cost Estimate

In addition to the EpCM capital cost estimate, Black & Veatch prepared a "developer-led" capital cost estimate. In such a scenario, it is envisioned that a cost savings of approximately 25 to 30 percent could be realized by having a developer lead the execution of the project, rather than a third-party EpCM contractor. The following adjustments to the capital cost estimate were made based such an execution approach:

- Overall reduction in engineering costs (with engineering costs taken out of the digester design and moved to the integrated Engineering budget).
- Reduced labor hours and increased labor efficiency, leveraging the experience and lower blended labor costs with an experienced digester developer team engaged.
- Contingency eliminated from the budget to reflect the lower potential cost range for the project.
- Reduced or eliminated material cost contingencies in several categories associated with no longer having a third-party EpCM integrator.

4.2.2 Capital Cost Estimate

A summary of the capital cost estimate is shown in Table 4-2; the full cost estimate basis and detailed capital cost estimate are attached in Appendix K. The total capital cost for the project is estimated to be in the range of $7,209,000 to $9,761,000.

Table 4-2 Capital Cost Estimate

DESCRIPTION	EpCM CAPITAL COST	DEVELOPER-LED CAPITAL COST
Direct Costs		
Site Work	$835,000	$835,000
Foundations and Concrete	$175,000	$162,000
Steel	$320,000	$250,000
Fire Protection System	$300,000	$150,000
Lagoon Digester	$2,279,000	$1,710,000
Biogas Cleaning System	$1,925,000	$1,500,000
Refueling System	$862,000	$854,000
Piping	$460,000	$130,000
Electrical Equipment and Bulks	$547,000	$390,000

DESCRIPTION	EpCM CAPITAL COST	DEVELOPER-LED CAPITAL COST
Insulation and Painting	$62,000	$59,000
Productivity Adjustment	$124,000	$0
Total Direct Cost	$7,889,000	$6,107,000
Indirect Costs		
Construction Management and Startup Staff	$420,000	$210,000
Subcontractor Indirects	$479,000	$192,000
Engineering	$508,000	$700,000
Contingency	$465,000	$0
Total Indirect Field Costs	$1,872,000	$1,102,000
TOTAL CAPITAL COST	**$9,761,000**	**$7,209,000**

4.2.3 Operations and Maintenance Cost Estimate

The O&M cost estimates were developed on the basis of the following operational assumptions:

- **Capacity Factor:** The gross capacity factor of the facility is assumed to be 95 percent. Therefore, the plant would be operational for approximately 8,322 hours per year and would be out of service for approximately 438 hours per year.
  - Scheduled maintenance would require 2 weeks per year. This accounts for approximately 340 hours per year of "out-of-service" hours.
  - The remainder of out-of-service hours are allocated for forced outages (e.g. lack of biogas supply, upgrading equipment failures, power outages, etc.).
- **Operational Strategy and Staffing:** The digester, gas cleaning, and refueling systems are assumed to be operated in an unattended manner, with minimal on-site staff required for monitoring and response to alarms.
  - It is assumed that facility staffing would require 2 full time equivalents for on-site monitoring and facility administration.
  - The burdened wage rate for staff is assumed to be $65,000 per year.
- **Adsorbent Media Costs:** H_2S adsorbent media costs were estimated assuming a cost of $4.15 per pound of sulfur captured, based on in-house Black & Veatch data.
- **Cost of Utilities:** The cost of electricity, water and natural gas are based on estimates of current market rates in California.
  - The cost of electricity is assumed to be $0.11 per kilowatt-hour.
  - The cost of water is assumed to be $10.00 per 1,000 gallons.
  - The cost of propane is assumed to be $1.00 per gallon.

All O&M cost estimates are presented in 2019 USD. The estimated annual non-fuel O&M costs are summarized in Table 4-3 and are estimated at $515,000 per year.

Table 4-3 O&M Cost Estimate

DESCRIPTION	TOTAL COST
H_2S Removal Media Replacement	$43,000
Biogas Conditioning / Upgrading System Maintenance	$51,000
Refueling System Maintenance	$20,000
Electric Power	$205,000
Water Requirement	$0
Propane for Thermal Oxidizer	$19,000
Labor	$130,000
Contingency (10% of Subtotal)	$47,000
TOTAL O&M	**$515,000**

5.0 Future Hydrogen Utilization

Hydrogen is the most abundant element in the universe and its potential as a clean energy source both for transportation and domestic usage is being pursued by countries around the world. Australia and the city of Leeds, England both have programs to expand the use of hydrogen in domestic applications above and beyond a plurality of advanced economies that have been expanding hydrogen transportation programs. There is already a significant worldwide market for hydrogen. Hydrogen is primarily produced at scale today using steam reformation of fossil gas and as part of the refining process. However, to better address climate change, there are new production technologies for hydrogen that offer considerable promise.

California is in early stages of exploring the use of Hydrogen as a clean fuel source that can help meet California's Climate goals. Hydrogen production through electrolysis (power to gas) and biomass gasification offer potential solutions for the current obstacles in California's current state regarding climate: over production of renewable electricity and reducing wildfire risk. However, additional research and development is needed before California can adopt standards for using Hydrogen in domestic, commercial, and industrial uses.

Uses of hydrogen are growing but significant challenges remain, particularly with respect to distribution infrastructure. The proposed MPT Gas Microgrid offers an ideal pilot program to better understand the multi-faceted potential for hydrogen. The following subsections outline the current state-of-the-art and research needs in hydrogen production and usage, as well as the manner in which MPT could serve as a test bed to address issues associated with these topics.

5.1 SUITABILITY OF MPT FOR FUTURE HYDROGEN UTILIZATION

MPT could be used as a real world testing ground for hydrogen production and utilization, which would continue to position California as a world leader in addressing hydrogen, helping to advance the tremendous potential of this clean energy source. Key characteristics of the proposed MPT Gas Microgrid project that could fit into a hydrogen production and utilization approach including the following:

- MPT could use the RNG derived from the Phase 2 Project to produce hydrogen on-site.
- Electrolyzers could be installed to produce hydrogen for use in the MPT Gas Microgrid.
- The fueling infrastructure at MPT/Trinkler could also potentially be used to dispense hydrogen or hydrogen/RNG blends.
- An investigation of how to blend/extract hydrogen from the pipeline at MPT would be appropriate for its small scale.
- The performance of different appliances could also be an ideal study for the MPT community.
- Considering the impact to pipelines and costs/benefit of dedicated hydrogen pipes would be the focus of many of the proposed studies.

5.2 HYDROGEN UTILIZATION

5.2.1 Distribution

Hydrogen can be distributed in high-pressure, compressed gas tube trailers, cryogenic liquefaction systems, and pipelines. Most infrastructure studies have concluded that a pipeline network is the optimal long-term solution for hydrogen distribution. A pipeline network is scalable to handle large volumes within a populated area, will benefit from cost reductions with economies of scale, and can utilize geophysical storage. To date, most policy support and development efforts have been focused on hydrogen refueling stations for fuel cell electric vehicle (FCEV) transportation applications. This policy support is driving early consumer adoption of FCEVs and facilitating the advancement of the infrastructure supply chain, including compressed/liquefied hydrogen transmission and storage technologies. Approximately 80 percent of the current cost for dispensed hydrogen is due to the transportation, delivery, and refueling station costs (i.e. $2 per kilogram [kg] production, $3/kg transport and delivery, and $5/kg refueling station for a total indicative cost of $10/kg).

Blending hydrogen into existing natural gas pipeline networks has been considered, and concentrations of less than 5 to 15 percent hydrogen by volume appears to be viable with little changes to the existing natural gas transmission/distribution infrastructure and end-use appliances. However, any blend would require extensive studies and testing as well as modifications to the monitoring and maintenance practices of the existing infrastructure. Pure hydrogen can be delivered to markets using natural gas pipeline blended by using separation and purification technologies that would extract hydrogen from the natural gas blend close to the point of end use.

While using blended gas networks would avoid the cost of building dedicated hydrogen pipelines, it introduces additional costs to blend and extract the gases, as well as any infrastructure modifications required. Integrity management of blended pipelines will likely require increased costs due to additional leak detection systems and higher inspection frequencies. Gas leakage from pipelines is considered to be economically negligible; however, leakage due to seals at joints requires additional study, specifically in regard to leakage into confined spaces (National Renewable Energy Laboratory, 2013).

According to the Australian Commonwealth Scientific and Industrial Research Organization (CSIRO), the transport of 100 percent hydrogen via pipeline raises pipe embrittlement concerns, depending on the operating pressure and pipeline material of construction. The risk of embrittlement in domestic gas distribution networks is lower due to the lower operating pressures verses higher pressures of the transmission networks.

5.2.2 Domestic Usage

A study conducted by NaturalHy concluded hydrogen concentrations up to 28 percent (in natural gas) can be used with properly serviced domestic appliances, but that the impacts of using blended gas for industrial applications should be considered on a case-by-case basis (National Renewable Energy Laboratory, 2013). R&D investment priorities for hydrogen use in domestic applications include:

- Development of odorants that can be blended with hydrogen for leakage detection, as conventional natural gas odorants (i.e. sulfur-containing) could potentially contaminate appliances such as fuel cells.

- Flame enhancement additives may be required to ensure a visible flame.

The Australian Hydrogen Roadmap references the HyDeploy project in the United Kingdom, which suggests a hydrogen in natural gas concentration up to 20 percent by volume can be tolerated by conventional appliances (Australian CSIRO, 2018). Not long after the publication of this report, a trial was announced by Australian Renewable Energy Agency for the blending of hydrogen (at small percentages) into a local gas pipeline in western Sydney to demonstrate the concepts explored in the report (Zhou, 2018). Such a program would build upon the H21 Leeds City Gate project, which is targeting the conversion of its natural gas network to pure hydrogen by the 2030s and serve a community of 660,000 residents with decarbonized domestic heating fuel.

The ability of residential appliances to operate on blended natural gas and hydrogen without upgrades could allow a flexible rollout of decentralized hydrogen production, noting that an extensive rollout of hydrogen production (in Australia) is unlikely to occur prior to 2030. It is noted that to accommodate 100 percent hydrogen, existing residential appliances would need to be upgraded or replaced, and that the required design changes are relatively straight forward. Design changes for commercial and industrial applications are considered to be complex and would need to be evaluated on a case-by-case basis. It is suggested that the replacement of domestic appliances would be preferred to upgrading existing appliances, which is considered to be time consuming and expensive. Also noted is the option to replace natural gas appliances with electric appliances to be powered by domestic fuel cell combined heat and power (CHP) systems.

5.2.3 Transportation Fuel Usage

According to the California Air Resources Board (CARB), there are 36 Open-Retail hydrogen fueling stations across the state of California, which is expected to grow to 64 stations by the end of 2020 and 200 stations by 2025. CARB suggests that as more FCEVs are deployed, the refueling station network utilization rate will also increase, which will improve the business case for the Open-Retail stations (California Air Resources Board, 2018). The majority of refueling stations in California receive hydrogen via compressed gas deliveries (54 percent), on-site electrolysis (20 percent), or liquefied deliveries (18 percent), with total hydrogen dispensed across all stations at approximately 1,000 kg/day (National Renewable Energy Laboratory, 2019).

Light-duty FCEVs are considered to be mature and ready for mass-market deployment. CARB projects that the number of FCEVs in California will grow to 40,000 by 2024, and 300,000 by 2030. Strong global developments in FCEVs, stationary power, and other applications are projected to stimulate further technology improvements and drive down costs with mass production. The growth of the FCEV market is currently limited by fuel supply challenges including a lack of refueling stations, high hydrogen retail prices, and unreliable supply.

The advancement of medium-duty and heavy-duty FCEVs, which are currently in the prototyping stage of technology readiness, is expected to provide additional hydrogen demand growth. Refueling times ranging from 3 to 5 minutes and vehicle driving range exceeding 350 miles makes FCEV technology more competitive than Battery Electric Vehicle technology to replace diesel in these applications. A hydrogen-fueled fuel cell tractor by Nikola Motor shows promise in the heavy-duty fuel cell vehicle arena. The newly-unveiled Nikola hydrogen powered tractors already have more than 13,000 orders. The trucks have a range between 500 and 750 miles and a refueling time of less than 20 minutes. Additionally, Nikola Motor has a powersports division developing off-road vehicles and watercraft based on FCEV technology (Nikola Motor Company, 2019). Other companies advancing heavy-duty FCEV technology include Toyota, Kenworth, and Hyundai.

Noteworthy industrial applications for fuel cell technology include forklift trucks, distributed power generation/CHP, and energy storage. Fuel cell forklifts have been deployed throughout the country with little government incentives and are considered advantageous for their quick refueling times, small footprint, and lack of harmful emissions compared with battery- and engine-driven counterparts. The California Fuel Cell Partnership (CAFCP) estimates that more than 500 fuel cell forklifts have been deployed in the state, indicating the technology is fully mature.

Fuel cells have been used extensively for stationary power generation/CHP over decades with molten carbonate, phosphoric acid, and solid oxide technologies dominating the market. The CAFCP estimates that over 200 megawatts of stationary fuel cells have been deployed across the state, most of which are fueled by natural gas. With higher penetration of renewables, the need for seasonal energy storage becomes imperative. Hydrogen energy storage via electrolysis and fuel cells is a relatively immature application due to high costs, but the constituent technologies are considered advanced.

5.3 HYDROGEN PRODUCTION

Hydrogen is an energy carrier that can be produced from a wide variety of primary energy sources and used in a host of commercial and industrial applications. The US produces approximately 10 million metric tons (MMT) of hydrogen per year with worldwide annual hydrogen production estimated to be between 61 and 65 MMT. Approximately 60 percent of the hydrogen production in the US is done so on-site for use in petroleum refining and ammonia/methanol production. The remaining 40 percent is produced, shipped, and sold as an industrial gas in a variety of applications.

The US Department of Energy (DoE) supports a wide range of hydrogen production technologies having recently concluded research and development (R&D) efforts for hydrogen generation via steam methane reforming (SMR) and biomass gasification. Hydrogen generation via electrolysis is also considered a near-term technology; however, current R&D efforts are focused on lowering the cost of commercial systems. Mid- and long-term DoE hydrogen production pathways include reforming of liquid biofuels, microbial biomass conversion, novel electrolysis technologies, coal gasification with carbon capture and storage, photo-electrochemical water splitting, solar thermochemical, and photo-biological technologies (US Department of Energy, 2016).

According to the US DoE Fuel Cell Technologies Office (FCTO) Multi-Year Program Plan, DoE's primary goal is to reduce the cost of production of hydrogen, independent of technology pathway, to less than $2 per gallon of gasoline equivalent (GGE) and to less than $4/GGE delivered and dispensed (US Department of Energy, 2015). The DoE FCTO H2@Scale initiative extends the focus beyond transportation applications and funds R&D projects to address other industrial and domestic applications for hydrogen with a focus on infrastructure and end-use technologies (US Department of Energy, 2019).

5.3.1 Steam Methane Reforming

Hydrogen production via steam methane reforming (SMR) is considered a mature, commercialized technology. Fossil-based natural gas or RNG is combined with high-pressure steam and fed to a steam reforming reactor. The endothermic SMR reaction converts methane and steam over a catalyst into hydrogen and CO, also known as synthesis gas or syngas, which is further processed through a series of high- and low-temperature water gas shift (WGS) reactors to convert most of the remaining CO into hydrogen and carbon dioxide. A pressure swing adsorption (PSA) process is then used to separate the hydrogen from the remaining CO and methane and compress the gas to a suitable pressure for delivery and end use.

SMR is highly sensitive to the cost of natural gas feedstock, thus low-cost, fossil-based resources are often favored over RNG. Black & Veatch estimates the levelized cost of hydrogen to be in the range of $1 to $3/kg) corresponding to natural gas priced at $3 to $7/MMBTU. Current SMR R&D activities include:

- Development of new, economical catalysts and membranes that can operate at higher temperatures and pressures and facilitate improved conversions and product purity, respectively.
- Further development of structured and multilayered adsorbents will allow for further improvements to current PSA processes allowing for shorter cycle times and higher production rates.
- Process intensification, specifically the integration of the reforming, WGS, and separation unit operations.
- Further development of reforming catalysts, WGS catalysts, PSA adsorbents, separation membranes, and separation processes can continue to improve overall pathway efficiencies and reduce production costs.

5.3.2 Electrolysis

Hydrogen produced via electrolysis uses electricity to split water molecules into hydrogen and oxygen gases in a stack of electrochemical cells. Electrolysis is considered commercial at a small scale; however, there are challenges for the technology with respect to scale-up and realization of economies of scale. There are several different types of electrolyzer technologies, with alkaline and proton exchange membrane (PEM) technologies being considered the most prominent. Alkaline electrolysis is characterized as being durable, having relatively low capital costs due to the lack of noble metal electrocatalysts, and is based on technology dating back to the 1920s, thus is quite mature. PEM electrolyzers have high power density and flexible turn-down ratios, but currently demonstrate lower lifetimes and have higher complexity than alkaline.

As electrolysis uses electricity to generate hydrogen it is sensitive to the cost of electricity. Black & Veatch estimates the levelized cost of hydrogen via electrolysis to be in the range of $6 to $9/kg corresponding to electricity priced at $0.08 to $0.12 per kilowatt-hour. Current electrolysis R&D activities include:

- Component standardization and manufacturing scale-up for PEM electrolysis.
- Lower catalyst loadings, thinner membranes, and alternative bipolar plate materials of construction.
- System-level integration, process intensification, and water/hydrogen purification technologies.

5.4 CONCLUSIONS REGARDING HYDROGEN

The following conclusions are noted with respect to the potential for hydrogen utilization at MPT:

- Hydrogen is produced primarily via SMR and water electrolysis at a cost of around $1-$3/kg and $6-$9/kg, respectively.
- Hydrogen is distributed to end users primarily via compressed gas tube trailer, liquefied containment, or pipelines.

- Blending of hydrogen into existing natural gas supply infrastructure is considered feasible in the near term but will require modifications to existing monitoring and maintenance practices.
- The use of hydrogen in domestic applications is constrained primarily by safety and cost considerations, with more focus applied to distributed fuel cell power generation and usage of electric appliances, rather than replacing natural gas fueled appliances with those fueled by hydrogen.
- The use of hydrogen in light-duty FCEVs, forklifts, and for stationary power/CHP applications has matured extensively and is expected to continue to grow over the next few decades.
- Medium- and heavy-duty FCEVs are currently being prototyped and offer promise to increase demand for hydrogen as a transportation fuel.
- Similar to the City of Leeds, which plans to switch its entire natural gas distribution and utilization infrastructure to hydrogen, a plan could be developed and implemented to have the MPT community (and the associated residential appliances) changed over to be supplied with hydrogen in the future, rather than with RNG or natural gas.
- If a design change is made to shift from supplying RNG to 100 percent hydrogen, key issues to note include the following:
  - Replacement of major components within appliances may be required, potentially warranting procurement of new appliances altogether.
  - Assuming elastomeric materials typical of the natural gas industry are used in distribution lines, hydrogen should be compatible with these materials at low pressures.
  - Distribution meters should be able to be reused but would need to be calibrated for hydrogen.

6.0 Conclusions

Based on the findings of this study, Black & Veatch has developed the following conclusions and recommendations. These should be considered as PG&E continues to pursue the company's objectives regarding the production of RNG from dairy manure and utilization for transportation applications and localized gas distribution networks.

- Production of RNG using a lagoon digester, membrane-based biogas cleaning system, and on-site CNG refueling station is considered technically feasible at the scale of interest investigated by Black & Veatch.
- Black & Veatch established a conceptual design for a lagoon digester and RNG production facility at the Trinkler Dairy. The design indicated that manure from 1,500 milking cows (as well as from 1,380 other cows housed on-site) could produce 37,200 to 39,500 MCF/yr of RNG, well in excess of that predicted by PG&E in their business case for the Project.
- A preliminary permitting investigation found that the project may avoid a lengthy CEQA permitting process by requesting a modification to the current Use Permit to include an RNG production and distribution facility. If possible to install BACT equipment, it is advantageous to avoid major source permitting. A permitting period of 12 to 15 months is expected for the Project.
- The preliminary Project schedule shows a duration of 22 months from NTP to COD, including permitting, detailed engineering, procurement support, construction, and start-up/commissioning. An additional phase of preliminary engineering may be needed to prepare permit applications, and additional time for permitting may be needed as well.
- The capital cost for implementation of the Project is estimated to be in the range of $7,2 million to $9.8 million; where a developer-led approach is anticipated to be in the lower cost range, and an EpCM implementation approach is anticipated to be in the higher cost range for implementation of the Project.
- The O&M costs for the Project are expected to be around $515,000 per year, not including tube trailer transportation, which is also higher than that predicted by PG&E primarily due to higher electricity consumption.
- Beyond the scope of the Phase 2 MPT Gas Microgrid Project, Black & Veatch finds that MPT represents an attractive opportunity for a pilot program to explore the future use of hydrogen as an energy carrier in domestic applications.

7.0 References

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Appendix A. Acronyms

AD	Anaerobic Digestion
APCO	Air Pollution Control Officer
ATC	Authority to Construct
BACT	Best Available Control Technology
CARB	California Air Resources Board
CAFCP	California Fuel Cell Partnership
CEPA	California Environmental Protection Agency
CEQA	California Environmental Quality Act
CHP	Combined Heat and Power
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO	Carbon Monoxide
COD	Commercial Operation Date
CPUC	California Public Utilities Commission
CSIRO	Commonwealth Scientific and Industrial Research Organization
DAC	Disadvantaged Community
DoE	Department of Energy
EPC	Engineering, Procurement, Construction
EpCM	Engineering, Procurement Support, Construction Management
FCEV	Fuel Cell Electric Vehicle
FCTO	Fuel Cell Technologies Office
GA	General Arrangement
GGE	Gallons of Gasoline Equivalent
kg	Kilogram
kW	Kilowatts
LAER	Lowest Achievable Emission Rate
lb	Pounds
LCFS	Low Carbon Fuel Standard
MCF	Thousand Cubic Feet
MMBTU	Million British Thermal Units
MMT	Million Metric Tons
MPT	Monterey Park Tract
NO_X	Nitrogen Oxides
NPDES	National Pollution Discharge Elimination System
NSR	New Source Review
NTP	Notice to Proceed
O&M	Operations and Maintenance
PEM	Proton Exchange Membrane
PFD	Process Flow Diagram
PG&E	Pacific Gas & Electric
POR	Point of Receipt
ppm	Parts per Million
PSA	Pressure Swing Adsorption
R&D	Research and Development
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	Renewable Natural Gas

RWQCB	Regional Water Quality Control Board
scf	Standard Cubic Feet
scfm	Standard Cubic Feet per Minute
SIC	Standard Industrial Classification
SJV	San Joaquin Valley
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMR	Steam Methane Reforming
SO_X	Sulfur Oxides
TIC	Total Installed Cost
tpy	Tons per Year
TS	Total Solids
US	United States
USACE	US Army Corp of Engineers
USD	US Dollar
VOC	Volatile Organic Compound
VS	Volatile Solids
WGS	Water Gas Shift
WWSL	Wastewater Storage Lagoon
yr	Year

Appendix B. Design Basis Memorandum

FINAL

MONTEREY PARK TRACT GAS MICROGRID DESIGN BASIS

B&V PROJECT NO. 401616
B&V FILE NO. 40.0100

PREPARED FOR

Pacific Gas & Electric Company

20 MAY 2019

Table of Contents

LIST OF TABLES

1.0 General Information

Client's Name: Pacific Gas & Electric Company (PG&E)
Facility Location: Ceres, California (CA), USA
Unit Type: Renewable Natural Gas (RNG) Production and Distribution Facility

1.1 OBJECTIVE

The purpose of this document is to:

- Define the basis used for designing the RNG Production and Distribution Facility to serve the Monterey Park Tract (MPT) Gas Microgrid.
- Record input information received from the Client that will be used in the preparation of the design.

1.2 SCOPE

Black & Veatch is assisting with the design and development of an RNG Production and Distribution Facility that will receive manure from dairy cows, anaerobically digest the manure to produce biogas, and upgrade the biogas to RNG for distribution to multiple end users, including the MPT community. Black & Veatch's scope is to develop a conceptual design and cost estimate for the facility in cooperation with PG&E, Trinkler Dairy, and other stakeholders.

1.3 UNITS

Variables and engineering units to be used for this project are shown in Table 1-1.

Table 1-1 Variables and Engineering Units

Variable	Engineering Units
Temperature	°F
Pressure	
Near Atmosphere	psig
Above Atmosphere	psig
Below Atmosphere	in H_2O
Absolute	psia
Level	
Process	ft, inches
Storage tanks	ft, inches
Flow	
Gas Volume	SCFM
Gas Mass	lb/hr
Liquid Volume, Process flows	GPM
Liquid Volume, Utility flows	GPM
Liquid Mass	lb/hr
Solid Mass	lb/hr, tons/hr (tph)

Variable	Engineering Units
Electrical	
Voltage	V
Real power	W
Apparent power	VA
Motor power output	HP
Frequency	Hz
Distance	ft, inches
Velocity	ft/s, ft/min
Length	ft
Thermal Conductivity	BTU/(hr ft °F)
Gross Heating Value	BTU/lb
Net Heating Value	BTU/lb
Density	lb/ft^3
Weight	lb, tons
Soil Bearing Pressure	psf
Heat/Thermal Duty	MMBTU/hr
Sound Pressure Level	dBA

1.4 DESIGN CODES AND STANDARDS

The design and specification of work will be in accordance with applicable state and federal laws and regulations, and local codes and ordinances. The codes and industry standards used for design, fabrication, and construction are listed below and will be the editions in effect, including all addenda. Other recognized standards may also be used as design, fabrication, and construction guidelines when not in conflict with the listed standards. Applicable codes shall be finalized during detailed design:

- American Concrete Institute (ACI).
- American Institute of Steel Construction (AISC).
- American Iron and Steel Institute (AISI).
- American National Standards Institute (ANSI).
- American Petroleum Institute (API).
- American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE).
- American Society of Mechanical Engineers (ASME).
- American Society for Testing and Materials (ASTM).
- American Water Works Association (AWWA).
- American Welding Society (AWS).
- Applicable California Building Code.
- Applicable California Plumbing Code.
- Cooling Tower Institute (CTI).
- Compressed Gas Association (CGA).
- Concrete Reinforcing Steel Institute (CRSI).
- Environmental Protection Agency 40 CFR Part 60 and 40 CFR Part 75 (EPA).
- Illuminating Engineering Society (IES).
- Institute of Electrical and Electronics Engineers (IEEE).
- International Organization for Standardization (ISO).

- International Society of Automation (ISA).
- Insulated Cable Engineers Association (ICEA).
- National Electric Code (NEC).
- National Fire Protection Association (NFPA).
- National Institute of Standards and Technology (NIST).
- Occupational Safety and Health Administration (OSHA).

2.0 Site Information

2.1 SITE CONDITIONS

Site-specific design criteria are shown in Table 2-1.

Table 2-1 Site-Specific Design Criteria

Design Barometric Pressure:	14.66 psia [NOTE 1]
Elevation:	73 ft
Design Minimum Ambient Temperature:	20 °F [NOTE 1]
Design Maximum Ambient Temperature (dry bulb):	113.6 °F [NOTE 1]
Design Maximum Ambient Temperature (wet bulb):	79.3 °F [NOTE 1]
Notes: 1. Based on ASHRAE HVAC design data for 724926 weather station.	

2.2 DESIGN BASIS WATER

The well water and surface water used currently for dairy operations/irrigation should suffice and will have no impact on water quality requirements for the anaerobic digestion process.

2.3 ENVIRONMENTAL EMISSIONS AND EFFLUENTS

A permit has not been obtained yet for the site to host an RNG Production and Distribution Facility but will be evaluated as part of this study. Air emissions are expected from the emergency flare and thermal oxidizer for biogas upgrading off-gas streams. Liquid effluents are expected from anaerobic digestion include digestate, which is expected to be recirculated/field-applied. Both streams will be characterized as part of the design effort.

2.4 NOISE LIMITATIONS

The near-field noise emissions for each equipment component furnished shall not exceed a spatially-averaged, free-field, A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 ft above floor/ground level and any personnel platform during normal operation. The equipment envelope is defined as the perimeter line that completely encompasses the equipment package at a distance of 3-ft horizontally from the equipment face.

Where the drive motors, variable frequency drives (VFDs), or mechanical drives for the equipment are also furnished, the total combined near-field sound pressure level of the motor, VFD, or mechanical drive and the driven equipment measured as a single component, operating at design load, shall not exceed a spatially-averaged, free-field, A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 110 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

2.5 SITE ACCESS

The Trinkler Dairy site is located approximately eight miles south of Modesto in the town of Ceres, CA, which is in the San Joaquin Valley (SJV). The site address is 7251 Crows Landing Rd. and is located in between W. Taylor Rd. to the north and W. Zeering Rd to the south. Major transportation links in the vicinity include California Route 99 to the east and California Route 33/Interstate 5 to the west.

3.0 Utility Requirements

Utilities required for the facility are shown in Table 3-1.

Table 3-1 Utility Requirements

Utility	Utility Supply Information
Nitrogen	Bottles housed on-site for purging
Instrument Air	Expected to be used for control valves as part of biogas cleaning process, requirements to be defined by vendor
Process Water (non-potable)	Sourced from well and/or surface channel
Propane	Tank housed on-site for boiler gas, flare/oxidizer, and potentially heating for biogas cleaning process
Electrical Power Supply	Provided by Turlock Irrigation District (TID) Water & Power from local distribution circuit

4.0 Process Design Basis

4.1 PROCESS DATA TABLES

4.1.1 Feedstock

Table 4-1 shows the dairy manure feedstock basis. Manure and dilution water (i.e. digester influent) mass flow rates to be defined as part of mass balance task.

Table 4-1 Feedstock Design Basis [1]

Parameter	Unit	Milking Cows	Dry Cows	Heifers
Moisture	Wt%	87	87	83
Total Solids (TS)	Wt%	13.3	13.3	17.1
Volatile Solids (VS)	Wt% of TS	85	83.6	86.6
Nitrogen	Wt%	0.66	0.6	0.54
Phosphorus	Wt%	0.11	0.08	0.09
Total Manure	lb/day-animal	150	83	48
Total Manure	ft^3/day-animal	2.4	1.3	0.78

4.1.2 Digestate Composition

Digestate characteristics and flow rates to be defined as part of mass balance task.

4.1.3 Biogas Composition

Table 4-2 shows the expected biogas composition.

Table 4-2 Biogas Design Basis

Parameter	Unit	Value
Methane	Vol %	65
Carbon Dioxide	Vol %	32
Nitrogen	Vol %	1.9
Oxygen	Vol %	0.5
Water Vapor	Vol %	0.6
Hydrogen Sulfide	ppmv	2,000

4.1.4 RNG Composition

Table 4-3 shows the expected RNG composition.

[1] Moisture, TS, VS, Nitrogen, Phosphorus, and Total Manure all based on American Society of Agricultural and Biological Engineers Standard D384.2

Table 4-3 RNG Design Basis [2]

Parameter	Unit	Value
Methane	Vol %	TBD
Oxygen	Vol %	≤0.1
Nitrogen	Vol %	TBD
Carbon Dioxide	Vol %	≤1
Total Sulfur	ppm_v	≤17
Hydrogen Sulfide	ppm_v	≤4
Water Vapor	lb/MMSCF	≤7
Siloxanes	mg/Nm^3	0.1
Temperature	°F	60 ≤ T ≤ 100
Dew Point	°F	≤45
Heating Value	BTU/SCF	TBD
Wobbe Index	BTU/SCF	TBD

4.2 DESIGN CRITERIA

4.2.1 Anaerobic Digestion

The anaerobic digestion of dairy manure is typically performed in a covered lagoon for flush-type collection systems or a mixed plug-flow digester for scrape-type collection. The dairy manure digester process for a flush-type manure collection system (used at Trinkler Dairy) can be broken up into the following process steps:

- **Waste Reception:** Fresh manure and recycled flush water is pumped, hauled, or drained via gravity to a receiving pit.
- **Mechanical Pretreatment and Conditioning:** Mechanical pretreatment and conditioning may or may not be performed prior to digestion (e.g. sand separation between receiving pit and digester).
- **Anaerobic Digestion:** Manure is pumped from the receiving pit to the mixed or un-mixed and typically unheated digester. For most flush-type manure systems, a below-grade, covered lagoon is typically used. After digestion, the digestate is pumped to the storage lagoon.
- **Dewatering:** The digestate is typically used as agricultural fertilizer. A portion of the digestate may also be used as recycled flush water.
- **Biogas Utilization:** The produced biogas is sent to the cleaning and upgrading train for RNG production. A few hours of storage may be provided in a pad mounted membrane gas buffer. An emergency flare is provided in the event that the biogas utilization system is unavailable due to maintenance or malfunction and the produced gas is safely flared off.
- **Odor Treatment:** Odorous air is typically not treated as it is assumed that sensitive receptors are at adequate distance to the Dairy and digester installation.

Typical design and performance parameters (for unheated and unmixed) covered lagoon digesters are as follows:

- Total solids of digester feed: < 2%

[2] Per PG&E Gas Rule No. 21

- Volatile solids of digester feed: 70 – 85%
- Hydraulic retention time (HRT): 55 days
- Organic loading rate target: 10 pounds of VS per thousand cubic feet and day
- Specific biogas yield per VS input: 6 – 8 cubic feet per pound of VS fed to digester
- Average Specific biogas yield per VS excretion: 3.5 cubic feet of biogas per pound of manure VS excretion
- Specific biogas yield per VS consumed: 14 – 18 cubic feet per pound of VS consumed

4.2.2 Biogas Cleaning

Digester gas quality produced by manure digesters is similar regardless of the type of manure collection. As noted above, a scraped system is a good fit for a plug flow digester and lagoons may be appropriate for a covered lagoon system. However, data suggest the plug flow digester may produce more digester gas per pound of manure input owing to mixing and heating of the digester. Digester gas is composed of methane, carbon dioxide, nitrogen, oxygen and water vapor. Only methane has energy value. Contaminants such as hydrogen sulfide and volatile organic compounds (VOCs) may interfere with end uses and need to be removed from the gas stream. Raw digester gas also may contain particulates that can be trapped or filtered out of the gas stream.

The biogas cleaning system will upgrade the digester gas to RNG by separating methane from the digester gas and treat the gas to meet applicable pipeline or vehicle fuel standards. Nitrogen and oxygen occur in digester gas due to air intrusion and are not readily separated from methane. The effect of nitrogen and oxygen is to dilute the fuel value of the RNG. Ensuring a tightly sealed digester will reduced air intrusion and improve the energy content of the RNG product.

Since dairy manure is known to have significant concentrations of hydrogen sulfide (H_2S), the removal of sulfur is an essential element of the gas treatment requirements. The first step in gas treatment train may be H_2S removal as many adsorbents or biological systems require moist gas. The next step would be moisture removal to prevent condensation in the piping system. Moisture removal is accomplished by chilling the gas to a 40°F dewpoint to condense moisture and the reheat to 80°F to create separation from dewpoint. Siloxanes and VOCs are not typically found in digester gas from dairy manure so additional contaminant removal is not indicated.

The next step is separating the carbon dioxide from the methane, which is the key upgrading step. Several technologies to be considered for CO_2 removal are depicted in Table 4-4.

Table 4-4 Comparison of Characteristics of CO_2 Removal Technologies

TECHNOLOGY	METHANE CONTENT IN RNG (%)	METHANE LOSS (%)	REQUIRES WASTE GAS TREATMENT (1)	ELECTRICAL DEMAND (KW/SCFM)	WATER CONSUMPTION (GAL/1000 SCF)
PSA	98 to 99	1 to 2	Yes	0.45	0
Membrane (3-pass)	> 97	<1	No	0.48	0
Water Scrubbing	97 to 98	2 to 3	Yes	0.45	2
Amine Scrubbing	> 99	0.1	No	0.18 (2)	0.3

Notes:

(1) If the waste gas stream contains some quantity of methane in addition to CO_2, the waste gas must be sent to a thermal oxidizer or otherwise combusted prior to release to the atmosphere.

(2) Amine scrubbing require heat input as well not reflected in electrical demand

The Wobbe index for the RNG with 97 percent or greater methane and 1% or less CO_2 will be approximately 1,300 BTU/SCF. This energy density is suitable for pipeline injection and vehicle fuel use, so propane blending is not anticipated.

5.0 Civil/Structural Design Basis

5.1 ENVIRONMENTAL CRITERIA

Load calculations are based on ASCE 7-10.

5.1.1 Rainfall

- 100-Year, 1-Hour Rainfall: 1 inch
- 100-Year, 12-Hour Rainfall: 3 ½ inches
- 100-Year, 24-Hour Rainfall: 4 inches
- Maximum recorded in 24 hours (25-year frequency): 3 ½ inches

5.1.2 Wind

- Basic Wind Speed, mph: 115
- Exposure Category: C
- Topographic Factor, Kzt: 1.0

5.1.3 Seismic

- Short Period Mapped Spectral Acceleration, Ss: 1.088
- One Second Period Mapped Spectral Acceleration, S1: 0.378
- Site Class: C
- Importance Factor (Seismic Loads), Ie: 1.25

5.1.4 Snow

- Ground Snow Load, Pg, lb/ft^2: 0
- Importance Factor (Snow Loads), Is: 1.10

5.2 DESIGN CRITERIA

5.2.1 Design Loads

Design loads and load combinations for all buildings, structures, structural elements and components, handrails, guardrails, and connections shall be determined according to the criteria specified in this section (refer to Table 5-1). Loads imposed on structural systems from the weight of all temporary and permanent construction, occupants and their possessions, environmental effects, differential settlement, and restrained dimensional changes shall be considered.

The live loads used in the design of buildings and structures shall be the maximum loads likely to be imposed by the intended use or occupancy but will not be less than the minimum uniform live loads presented in Table 5-2. Components of the structural system may be designed for a reduced live load in accordance with the local building code. Roofs shall be designed to preclude instability resulting from ponding effects by ensuring adequate primary and secondary drainage systems, slope, and member stiffness. Structural elements supporting equipment shall be designed for the greater of the uniform live load or the loading imposed by the actual equipment.

Buildings and Other Structures

Process buildings shall have vertical bracing positioned to maintain a regular structure classification. Rigid structures, such as turbine equipment support structures, shall be isolated from the turbine building structure so that each provides its own discrete lateral force resisting system, unless coordinated and calculated to meet the regular structure classification.

All buildings shall have bracing located so as to minimize internal restraint to dimensional changes. Component supports and anchorages shall be configured so as to be rigid.

Table 5-1 Design Loads

Load Types	Criteria/Source
Dead Loads	ASCE 7-10, Tables C3-1 and C3-2.
Pipe Support, major piping (Major piping is defined as hot pipe greater than or equal to 2-1/2 inches [65 mm] in diameter and cold pipe greater than or equal to 24 inches [610 mm] in diameter.)	Specifically determined, including thermal and dynamic loads, and verified against final pipe routing and analysis.
Pipe Support, other piping and electrical conduit and cable tray	Preliminary design for uniform area, line, and/or concentrated loads located to create contingency moments and shears.
Live Loads	Calculated weight of the contents of tanks; movable loads, such as people, equipment, tools, and components during construction, operations, and maintenance; maximum loads likely to be imposed by intended use or occupancy, but not less than the loads in Table 5-2, nor actual equipment weight.
Impact Loads	Table 5-2 loads allow for ordinary impact conditions. Reciprocating or rotating machinery, elevators, cranes, pumps, and compressors shall have specific calculations addressing dynamic forces. Impact loads shall be as specified in ASCE 7 Chapter 4 unless analysis indicates higher values are required.
Soil and Hydrostatic Loads	Below grade structures shall include static and seismic lateral soil pressure, expansive soil pressures, hydrostatic pressure or buoyancy, compaction energy pressure, and potential surcharge loads from normal service or construction.
Wind Loads, buildings and structures	Basic design wind speed shall be in accordance with ASCE 7, Subsection 1.7.2. No shielding shall be permitted for ground conditions or for adjacent structural members.
Wind Loads, steel stacks	Loads and design in accordance with ASME STS-1.
Snow Load	Minimum ground snow load shall be in accordance with ASCE 7, Subsection 1.7.2. Drift loads shall be applied to roof discontinuities and roof regions shielded by large roof-mounted equipment or machine penthouses.
Ice Loads	Applicable to steel lattice type structures and guy cables. Ice accretion shall be in accordance with ASCE 7, Subsection 1.7.2. An ice density of 57 lb/ft^3 (915 kg/m^3) shall be used.
Seismic Loads, buildings (by building, if appropriate)	Refer to ASCE 7, Subsection 1.7.2.
Seismic Loads, components and attachments	Amplification and response modification factors in accordance with ASCE 7.

Load Types	Criteria/Source
Construction Loads, roads	AASHTO HS 20 or equivalent.
Fatigue Loads	In accordance with AISC Specification for Structural Steel Buildings.
Personnel Load	
Fixed Metal Ladders	One 300 pound load for every 10 feet of ladder height or two 300 pound concentrated loads between any two consecutive attachments, whichever is greater. Rungs are designed for a single concentrated load of 300 pounds.
Stairs	1,000 pound concentrated load applied at any point. Non-concurrent with 100 psf live load in Table 5-2.

Table 5-2 Minimum Uniform Live Loads

Area	Live Load, psf (kN/m^2)
Ground Floor Slabs	
Boiler area	150 (7.2)
Turbine area	150 (7.2)
Shops, warehouses	125 (6.0)
Other structures	100 (4.8)
Suspended Floors	
Turbine operating floor	Weight of major components, but not less than 250 (12.0)
Control Room	100 (4.8)
Storage Areas	Weight of stored material, but not less than 125 (6.0)
Other Concrete Floors	100 (4.8)
Grating Floors	60 (2.9)
Roofs	20 (1.0)
Stairs	100 (4.8)
Cooling Tower Decks	60 (2.9)

Construction Loads

Construction or crane access considerations may dictate the use of temporary structural systems. Special considerations will be made to ensure the stability and integrity of the structures during any periods involving use of temporary bracing systems.

Wheel Loads

Wheel loads will be considered for roadway pavements, bridges, buried piping, culverts, and embankments. Roadway subgrades, pavements, and structures shall be designed for HS20 or equivalent load.

5.2.2 Architecture

Exterior Architecture Criteria

The exterior architectural systems provide a durable, weathertight enclosure to protect systems and personnel and allow for a controlled interior environment. Exterior architectural systems shall conform to the general design criteria in Table 5-3 for main plant buildings and principal yard buildings.

Interior Architecture Criteria

The interior architectural systems provide a functional, low maintenance, aesthetically pleasing environment. The materials in Table 5-4 have been selected to provide durability and offer flexibility in responding to occupant demands, while satisfying project and code requirements. Interior architectural systems shall conform to the general design criteria in Table 5-4 for main plant buildings and principal yard buildings.

Egress Criteria

Equipment platforms are considered unoccupied spaces as defined by IBC and access to them will be as required by NFPA 101 Chapter 40. Following is a list of equipment platforms that will follow the Chapter 40 requirements:

- Process unit stair towers that service open structures and platforms.
- Tanks.
- Cooling towers.
- Utility racks.

Table 5-3 Exterior Architecture Criteria

Item	Criteria
Walls	May consist of insulated or uninsulated metal wall panel. Building enclosures may also be preengineered.
Roofs	May consist of an insulated metal standing seam panel system or single-ply membrane over insulation and a metal roof deck.
Masonry	May consist of concrete block, which may be utilized for enclosure and separation purposes.
Thermal Insulation	Shall have insulation incorporated into the walls and roofs for thermal design and meet energy codes.
Acoustical Insulation	Shall have insulation incorporated into the walls and roofs for acoustical design.
Louvers	Shall include vertical storm louvers as required by the ventilation design.
Windows	May include windows, frames, and glazing. Selection shall be based on project and environmental requirements.

Item	Criteria
Personnel Doors	Shall include hollow, metal type personnel doors. Insulation and fire rating criteria shall be dictated by the interior and environmental requirements.
Equipment Access Doors	Shall include large exterior doors of the rolling metal type, with weather seals and windlocks.
Finish Painting	Exterior steel materials not galvanized or factory finished shall be field painted. Colors shall be selected and will harmonize with the project color scheme.

Table 5-4 Interior Architecture Criteria

Item	Criteria
Partitions	Partitions constructed of masonry, drywall, or metal wall panel.
Windows	Interior fixed windows as required by the occupancy. Rated and nonrated glazing shall be installed in accordance with fire and building code criteria.
Personnel Doors	Hollow, metal type personnel doors. Insulation and fire rating criteria shall be dictated by the interior and environmental requirements.
Ceilings	Ceilings in finished areas of the main buildings and principal yard buildings shall generally consist of suspended, exposed grid, lay-in acoustical type systems. Wet areas shall consist of moisture resistant materials.
Floor Coverings	Floor coverings in finished areas shall generally consist of resilient tiles or carpet tiles. Floor coverings in control and electrical equipment rooms may be static dissipative. High moisture areas shall incorporate unglazed ceramic tiles.
Wall Coverings	Glazed wall tiles shall be used in shower and toilet rooms as required for maintenance and sanitary requirements. All other finished area walls shall be coated as identified in the painting section.
Finish Painting	Interior areas shall be coated where required for chemical resistance, light reflection, or aesthetics.
Sanitary Facilities	Toilet and shower facilities and associated accessories shall be provided where required to meet code and project requirements.

In open structures, such as process units and cooling towers, plant scheduled routine maintenance shall be achieved with three or less occupants. Egress for plant scheduled routine maintenance is accomplished with a common path of travel of 200 feet and/or a ladder used as a second means of egress. Occupancy limits of the structure shall be achieved through signage and Owner administrative controls.

5.2.3 Concrete

Reinforced concrete structures shall be designed in accordance with ACI 318, Building Code Requirements for Structural Concrete, and the design parameters in Table 5-5, Table 5-6, and Table 5-7.

Mix Design

Mix design shall be in accordance with Table 5-5. A larger coarse aggregate size may be considered for mass concrete. Grout is "sand-only" mix.

Table 5-5 Mix Design

Mix Class	Maximum Exposure Classes *	Usage	Design Strength at 28 Days, psi (kPa)	Cement Type	Maximum Water/ Cementitious Materials Ratio	Air Content, percent	Maximum Coarse Aggregate Size, in. (mm)	Max Slump, in. (mm)
A1	NA	Lean work slabs, duct bank, fill concrete	2,000	I, II, or V	0.75	0	1.5 (38)	6 (150)
B1	F0 S0 P1 C1	General usage – no freeze/thaw	4,000	I, II, or V	0.50	3-6	1 (25)	4 (100)
B2	F2 S0 P1 C1	General usage – with freeze/thaw	4,500	I, II, or V	0.45	6	1 (25)	4 (100)
C1	F2 S1 P1 C1	Structure in contact with water or exposed to moderate sulfate exposure	4,500	I (C_3A<5%), II, or III (C_3A<8%),	0.45	6	1 (25)	4 (100)
C2	F2 S2 P1 C1	Structure in contact with water or exposed to severe sulfate exposure	4,500	I (C_3A<5%), III (C_3A<8%), or V	0.42	6	1 (25)	4 (100)
D1	F0 S0 P1 C1	Foundation piers and cased reinforced concrete piling – no freeze/thaw	4,500	I, II, or V	0.50	0	0.75 (20)	4 (100)

Mix Class	Maximum Exposure Classes *	Usage	Design Strength at 28 Days, psi (kPa)	Cement Type	Maximum Water/ Cementitious Materials Ratio	Air Content, percent	Maximum Coarse Aggregate Size, in. (mm)	Max Slump, in. (mm)
D2	F2 S0 P1 C1	Foundation piers and cased reinforced concrete piling – with freeze/thaw	4,500	I, II, or V	0.45	6	0.75 (20)	4 (100)
E1	F0 S0 P1 C1	Underwater concrete	4,000	I, II, or V	0.45	3-6	1 (25)	6-9 (150-225)
F1	F2 S2 P1 C1	Sulfur pits	4,500	V (C_3A<6%)	0.40	6	0.75 (20)	3 (75)

* Refer to Chapter 4 of ACI 318 for exposure classes.

Materials Usage

Table 5-6 Materials Usage Requirements

Material	Usage	Requirements
Cement	In accordance with Mix Design, local supply	ASTM C150/C150M.
Water	In accordance with Mix Design, local supply	Potable.
Aggregate	In accordance with Mix Design, local supply	ASTM C33/C33M.
Reinforcing Steel, main	In accordance with detail design requirements	ASTM A615/A615M, Grade 60.
Reinforcing Steel, ties and stirrups	In accordance with detail design requirements. Typically, No. 4 (D13)	ASTM A615/A615M, Grade 60.
Forms	All exposed concrete surfaces (not flatwork)	Plywood or modular steel, dimensions to nearest inch.

Materials Application

Table 5-7 Materials Application Criteria

Member	Criteria
Suspended Slabs	Two-way reinforced; 3/4 inch (20 mm) minimum cover; 6 inch (150 mm) minimum thickness; steel trowel finish; spray with curing compound.
Structural Beams	Singly reinforced; 3/4 inch (20 mm) minimum cover interior, 1-1/2 inch (40 mm) cover exterior; beam width in 2 inch (50 mm) increments, minimum 8 inches (200 mm); beam depth in 2 inch (50 mm) increments, minimum 12 inches (300 mm); cured 3 days in forms.
Grade Beams	Singly reinforced; 1-1/2 inch (40 mm) cover; beam width in accordance with excavator requirements, minimum 8 inches (200 mm); void forms between pier supports, 4 inch (100 mm) minimum thickness.
Spread Footings	6 inch (150 mm) dimension increments for footing dimensions less than 9 feet (2,740 mm); 3 inch (75 mm) bottom cover on soil; 1-1/2 inch (40 mm) bottom cover on mudmat.
Special Massive Machine Foundations	1-1/2 inch (40 mm) cover; dimensions to nearest 2 inches (50 mm), unless specifically for machine interface as required; reinforced for surface crack control.

5.2.4 Steel Structures

Steel framed structures shall be designed in accordance with the AISC Specification for Structural Steel Buildings. In addition, steel framed structures shall be designed in accordance with the criteria discussed in the following subsections.

Materials

Construction of steel structures shall use materials as defined in Table 5-8.

Table 5-8 Structural Steel Materials

Material	Criteria
Structural steel wide flange and WT shapes	ASTM A992/A992M.
Structural steel channels	ASTM A992/A992M; ASTM A572/A572M, Grade 50; ASTM A36/A36M.
Structural steel S shapes	ASTM A36/A36M; ASTM A992/A992M; ASTM A572/A572M, Grade 50.
Structural steel angles and plates	ASTM A572/A572M, Grade 50; ASTM A529/A529M, Grade 50; ASTM A36/A36M.
Structural steel baseplates and plate over 4 inches thick	ASTM A36/A36M.
Hollow structural shapes, round, rectangular or square	ASTM A500/A500M, Grade C.
High Strength Bolts	ASTM A325, 3/4 inch, 7/8 inch, or 1 inch diameter, 1/4 inch increments of length, 1/4 inch increments on bolt diameter when different bolt sizes are used, fully-tensioned bearing type designed with threads included in the shear plane for all connections except where slip-critical connections are required. Connections with oversized holes or slots in the direction of load are slip critical. ASTM A325M, M20, M22, or M24, 5 mm increments of length, 4 mm increments on bolt diameter when different bolt sizes are used, fully-tensioned bearing type designed with threads included in the shear plane for all connections except where slip-critical connections are required. Connections with oversized holes or slots in the direction of load are slip critical.
Weld Filler Metal	70 ksi (485 MPa) tensile strength.
Atmospheric Corrosion-Resistant Steel	ASTM A588/A588M.
Extreme Corrosion-Resistant Stainless Steel	ASTM A167, type as required.
Guardrail and Handrail	Steel pipe 1-1/2 inch (38 mm) diameter, ASTM A53/A53M, Type E or S, Grade B; HSS 1.9 inch (48 mm) diameter, ASTM A500, Grade C; Guardrail only - Steel angles 2-1/2 x 2-1/2 x 1/4 inch (64 x 64 x 6.4 mm).
Kickplate (Toeplate)	Fabricated from ASTM A36/A36M plate 4 inches x 1/4 inch (100 mm x 6 mm).

Material	Criteria
Steel Grating	3/16 inch by 1-1/4 inch (5 mm by 32 mm) bearing bars, galvanized.
Anchor Rods, sized for design loads	ASTM F1554, Grade 36 , 1/2 inch (13 mm) increments of diameter.
Anchor Rods, sized for design loads and pretensioned	ASTM F1554, Grade 105, 1/2 inch (13 mm) increments of diameter.
Stair Treads	Steel grating, cast abrasive or bent checker plate nosings.
Metal Deck, roof	1-1/2 inch (38 mm) profile depth, 22 gauge minimum, galvanized.
Metal Deck, form	1 inch (25 mm) profile depth, 24 gauge minimum, painted or galvanized (composite deck form only).
Ladders	Fabricated from ASTM A36/A36M bar rails 3 inches x 1/2 inch (75 mm x 13 mm) with 3/4 inch (19 mm) diameter rungs.

Design

Construction of steel structures shall use design practices defined by local building codes, but not less than those defined in Table 5-9.

Table 5-9 Structural Steel Design

System	Criteria
Lateral Building Drift, rigid frame structures	(Story or building height)/100 under wind, ASCE 7 for seismic.
Lateral Building Drift, braced frame structures	(Story or building height)/200 under wind, ASCE 7 for seismic.
Vertical Bracing Members	Designed and detailed for concentric loading, unless analyzed for work point and shape eccentricity. Compression and tension capable, “pinned” at all connection points.
Horizontal Bracing Members	Designed and detailed for concentric work point loading and eccentric shape loading. Compression and tension capable, “pinned” at all connection points.

System	Criteria
Beams - Lateral-Torsional Buckling Brace Points	The following shall be considered as points of lateral-torsional stability bracing for beams: • Roof deck connections, Lb = 3 times deck fastener spacing • Floor deck connections, Lb = Lesser of 3 times deck fastener spacing or the actual shear connector spacing • Floor grating, welded connections--Use 1-inch (25 mm) fillet welds at 12-inch (300 mm) spacing (min.), add drawing notes to caution against removing grating, Lb = weld spacing • Horizontal truss panel point incident beams--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams axially aligned with horizontal truss panel points--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connected to H-brace stability connections--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connected to floor slabs or roof truss diaphragms--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connecting three or more parallel beams, parallel beams have 20 percent or less difference in weight--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connecting two parallel beams--Verified by calculation only

System	**Criteria**
Columns - Lateral-Torsional Buckling Brace Points	The following shall be considered as points of lateral-torsional stability bracing for columns: • Incident beams connected to the space truss--Note for standard column sizes (W14 [W360] and smaller), incident beams connecting to the center of the column web restrain the column flanges against lateral buckling. For deep columns (W16 [W410] and larger), the incident beams may require special connections to restrain the column compression flange(s) against lateral movement. • Incident beams connecting three or more adjacent columns--Note for standard column sizes (W14 [W360] and smaller), incident beams connecting to the center of the column web restrain the column flanges against lateral buckling. For deep columns (W16 [W410] and larger), the incident beams may require special connections to restrain the column compression flange(s) against lateral movement. • Girts with flange braces
Beams - Major Axis Compression Buckling Brace Points	The major axis compression buckling points for beams shall occur only at the beam supports. Major axis unbraced length for beams, L_x, shall equal the beam span.
Beams - Minor Axis Compression Buckling Brace Points	The following shall be considered as points of weak-axis compression-buckling stability bracing for beams: • Horizontal truss panel points with or without incident beams • Incident beams axially aligned with horizontal truss panel points • Incident beams connected to floor slabs or roof truss diaphragms
Columns - Major and Minor Axis Compression Buckling Brace Points	The following shall be considered as points of compression-buckling stability bracing for columns: • Incident beams connected to the space truss • Incident beams connecting two adjacent columns--Verified by calculation only
Vertical Braces - Compression Buckling Brace Points	The following shall be considered as brace points for vertical bracing: • Buckling in the plane of the truss--“X-bracing” or single side strut • Buckling out of the plane of the truss--“X-bracing”
Unbraced Length, pipe bracing in ducts	$KL/r \leq 120$, checked for vortex shedding in flow and thermal restraint forces.
Deflection, floors and roofs, live load only	Span/360, vertical, unless attached to more rigid, brittle members.
Deflection, floors and roofs, dead and live load combined	Span/240, vertical.

System	Criteria
Deflection, girts	Span/180, horizontal. Span/240, vertical. When over or under glass, Span/360, horizontal. Span/960, vertical.
Deflection, crane and hoist support beams (without "impact")	Span/600, vertical; span/400, lateral.
Fixed ladder fall prevention (for OSHA compliant projects)	Ladders with the top rung more than 24 feet above a lower level will be provided with a fall prevention device. Ladders 24 feet or less above a lower level are not required to have fall protection.

5.2.5 Site

Grading and Drainage

Site grading and drainage shall be designed to comply with all applicable federal, state, and local regulations, and shall be integrated with existing site drainage systems so far as possible.

Roads

Road design component criteria are defined in Table 5-10.

Fencing and Security

The perimeter fence around the site boundary shall be woven wire. The perimeter fencing system shall include normally locked swing gates for access. The fence fabric shall be placed on the opposite side of the secure side of the fence.

Table 5-10 Site Design Component Criteria

Design Component	Criteria
Grading Slope, minimum	0.5 percent in main plant complex, or as appropriate for surface type, conveying storm runoff away from permanent facilities.
Roadway Linear Slope, maximum	8 percent unless Owner approves a steeper slope.
Finish Floor Relative Elevation	6 to 12 inches (150 to 300 mm) above 1 percent probability (100 year) storm event.
Culverts	Reinforced concrete, corrugated metal, or corrugated high density polyethylene (HDPE) pipes; reinforced concrete box where necessary.
Drainage Facilities and Water/Wastewater Storage Pond Storm Event, unless local code or regulations control	25-year, 24-hour rainfall event
Roads, main plant access	Two 10-foot (3.0 m) asphalt paved lanes, optional 3-foot (0.9 m) aggregate surfaced shoulders.
Roads, other than main plant access	Two 10-foot (3.0 m) aggregate surfaced lanes, no shoulders.

5.2.6 Foundations

General Criteria

Foundations shall be designed using reinforced concrete to resist the loading imposed by the building, structure, tanks, or equipment being supported. The foundation design shall consider the following:

- Soil bearing capacities.
- Deep foundation capacities.
- Lateral earth pressures.
- Allowable settlements, including differential settlements.
- Structure, equipment, and environmental loadings.
- Equipment performance criteria.
- Access and maintenance.
- Temporary construction loading.
- Existing foundations and underground structures including their current settlement conditions.

Foundations shall be designed using static analysis techniques assuming rigid elements and linear soil pressure distribution so that the allowable settlement and bearing pressure criteria are not exceeded. Foundations shall be proportioned so that the resultant of the soil pressure coincides as nearly as possible with the resultant of the vertical loading. The minimum factors of safety against overturning and sliding shall be 1.5. Factor of safety against sliding for retaining walls shall also be 1.5.

When using ASCE 7 load combinations that apply a 0.6 factor on dead load, the factor of safety for overturning and sliding is automatically set at approximately 1.67. For these special ASCE 7 ASD load combinations, the ratio of resisting forces (0.6 dead load) over driving forces (wind, seismic, or lateral loads) should be greater than 1.0 instead of 1.5.

Geotechnical exploration, testing, and analysis information shall be used to determine the most suitable foundation system. Elastic (short-term) and consolidation (long-term) foundation settlements shall be calculated and limited to the following approximate design values except where loading onto or differential settlements relative to existing structures may require more conservative criteria:

- Total settlement: 1-1/2 inches (38 mm).
- Differential settlement: 0.1 percent slope between adjacent column support points.

Allowable settlement is higher for tanks. These settlements will be calculated on an individual basis.

Special Foundation Requirements for Chimneys and Stacks

The foundation component for the chimneys and stacks shall be a circular or polygon shaped pier, pile, or ground supported, reinforced concrete foundation. The foundation shall be proportioned so that the bearing and allowable settlement criteria shall not be exceeded, with no uplift permitted and no increase in allowable bearing for wind load for soil supported foundations. For pile supported foundations, uplift on piles is allowed. Design settlement, elastic plus consolidation, shall be limited to approximately 1-1/2 inches (38 mm) for soil supported foundations.

Special Foundation Requirements for Rotating Equipment

The foundation systems for major rotating equipment shall be sized and proportioned so as not to exceed the bearing and settlement criteria, and to ensure satisfactory performance of the equipment. In addition to a static analysis, a dynamic analysis may be performed to determine the fundamental frequencies of the foundation system for selected major rotating equipment as determined necessary by Black & Veatch. To preclude resonance, fundamental frequencies of the foundation associated with rigid body motion shall be 25 percent removed from the operational frequency of the equipment. Should the foundation system not meet these criteria, a balance quality grade, appropriate for the equipment, will be determined from ISO 1940, Balance Quality Requirements of Rigid Rotors - Part 1. The dynamic behavior of the foundation will be evaluated for this level of unbalance and compared to ISO 10816, Mechanical Vibration-Evaluation of Machine Vibration by Measurements on Nonrotating Parts, Parts 1 through 6. The resultant vibration level shall not exceed the limit for evaluation of this standard. Where required, the foundation shall also be designed to meet manufacturer's requirements.

Foundation Design Criteria

Foundations to be designed per the geotechnical report to be provided by Trinkler Dairy.

Equipment Bases

All equipment shall be supplied with an equipment base suitable for its operation. Where the equipment could induce vibration problems, the base shall have adequate mass to dampen vibration motions. Special consideration shall be given to vibration and stiffness criteria where specified by an equipment manufacturer.

Equipment bases may be concrete or an integral metal skid. Concrete bases shall have minimum temperature and shrinkage reinforcing; unless it is determined that additional reinforcement is required for the equipment loads.

Insulation

When required by the local code, foundations and below grade portions of space-conditioned buildings above those foundations shall be insulated.

6.0 Mechanical Design Basis

6.1 DESIGN CRITERIA

6.1.1 Piping, Components, and Accessories

The requirements for piping, components, and accessories are shown in Table 6-1 by system/process.

Table 6-1 Piping, Components, and Accessories Requirements

Fluid Code	Power System Code	System/ Process Area	Flange Rating (B16.5)	Pipe Material	Special Requirements	Post-Weld Heat Treatment (PWHT)	Notes
GF	FGA	Fuel Gas	1500	CS 304	Fire safe		G01
	DGG	Digester Gas	150	304 PVC			G01 201, 202, 204
WW	WWC	Waste Water	150	FRP-Epoxy			G01
WW	WWC	Waste Water (U/G)	200 psi 150	HDPE DI	Cement-Mortar lined		G01, 501, 505, 603
AI	CAB	Instrument Air	150	304			G01
GN2	PMB	Nitrogen	150	CS			G01, G04, G08, 902
GC02	CGB	Carbon Dioxide	300	CS		B31.1	G01
WU	WSA	Utility Water	150	CS			G01, G04, G08, 902
WU	WSA	Utility Water (U/G)	200 psi	HDPE 4710			G01, 501, 505
FPW	STG, WSE	Fire Protection	150	CS	UL/FM Approved - VICTAULIC		G01, 702, 902
WF	STG	Fire Protection (U/G)	200 psi	HDPE 4710	31PFNF: UL/FM Approved/11PFNF: AHJ to be consulted for fire water application		G01, 501, 503, *Allowable Stresses for PE4710 pending approval of the AHJ.

Notes:

G01 – Addition or substitution of components (material A vs. material B, welded vs. seamless, etc.) in this piping class requires approval from the piping engineer.

G04 - Threaded components are permitted only at outlet of vent, drain, and instrument valves and to match equipment.

G08 - Component wall thickness and end preparation type to be the same as the pipe.

201 - Materials in contact with the piped fluid, including solvent cement, shall be suitable for continuous service with aqueous solutions containing up to 12.5% sodium hypochlorite.

<table>
<tr><th>Fluid Code</th><th>Power System Code</th><th>System/ Process Area</th><th>Flange Rating (B16.5)</th><th>Pipe Material</th><th>Special Requirements</th><th>Post-Weld Heat Treatment (PWHT)</th><th>Notes</th></tr>
<tr><td colspan="8">202 - PVC & CPVC pipe and fitting joints shall be made in accordance with the Manufacturer’s recommendations using solvent cement as specified by ASTM F493.
204 - Non-standard size reducing tees may be produced by solvent cementing reducing bushings with socket tees or reducing socket tees, utilizing the minimum standard components.
501 - Pipe and fittings to be manufactured to iron pipe size (IPS) dimensions. Pipe, fittings, and branches shall be joined per ASTM F2620, “Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings” and the “PPI Handbook of Polyethylene Pipe Joining Procedures.”
503 - HDPE pipe, fittings, flanges, and gaskets in fire protection water service shall be FM Approved for Fire Protection use.
505 - Pipe, fittings, and branches shall be joined in accordance with ASTM D2657, “Standard Practice for Heat Fusion Joining of Polyolefin Pipe and Fittings”, and the “PPI Handbook of Polyolefin Pipe Joining Procedures”.
603 – Minimum Type “3” laying conditions require (ANSI/AWWA C151/A21.51)
702 - Pipe, fittings, flanges, gaskets, and valves shall be UL Listed or FM Approved for fire water service.
902 - A106-B pipe is an acceptable substitute for A53-B pipe. As applicable, seamless fittings are acceptable substitutes for welded fittings.</td></tr>
</table>

6.1.2 Valves

The valve selection criteria are shown in Table 6-2 by system/process and the short-hand acronyms and type classifiers used in this table are identified in the associated legend present in Table 6-3.

Table 6-2 Valve Selection Criteria

	Isolation				Throttling				Vent		Drain	
	≤ 2”		≥ 2.5”		≤ 2”		≥ 2.5”					
	Type	End	Type	End	Type	End	Type	End	Type	End	Type	End
Fuel Gas Supply	B P	SW	B P	BW FLG	T F B	SW FLG	T F	BW FLG	B P	SW	B P	SW
Digester Gas	B	SW	B F	FLG	NA	NA	NA	NA	B	SCRD	B	SCRD
Waste Water	B G	SW FLG	G F	FLG WFR	T	SW SCRD FLG	F T	WFR FLG BW	B G T	SW FLG	B G	SCRD SW FLG
Waste Water (U/G)	B G	SW FLG	G F	FLG WFR	T	SW SCRD FLG	F T	WFR FLG BW	B G T	SW FLG	B G	SCRD SW FLG

	Isolation				Throttling				Vent		Drain	
	≤ 2”		≥ 2.5”		≤ 2”		≥ 2.5”					
	Type	End	Type	End	Type	End	Type	End	Type	End	Type	End
Compressed (Station) Air	B	P-FIT	G	BW FLG	T	P-FIT FLG	T F	BW FLG	B	P-FIT SCRD BR	B	P-FIT SCRD BR
Instrument Air	B	P-FIT	G	BW FLG	T	P-FIT FLG	T F	BW FLG	B	P-FIT SCRD BR	B	P-FIT SCRD BR
Nitrogen	B	P-FIT SCRD BR	G	BW FLG	T	P-FIT SCRD	T F	BW FLG	B	P-FIT SCRD	B	P-FIT SCRD BR
Carbon Dioxide	B	P-FIT SCRD	G	BW FLG	T	P-FIT SCRD	T F	BW FLG	B	P-FIT SCRD	B	P-FIT SCRD
Service Water	B G T	P-FIT SW	F G	WFR FLG	T	P-FIT SCRD SW	F T	WFR FLG BW	B G T	P-FIT SCRD SW	B G	P-FIT SCRD SW
Fire Protection Water	G	SCRD	G	FLG	T	SCRD	T	BW FLG	G	SCRD	G	SCRD
Fire Protection Water (U/G)	G	SCRD	G	FLG	T	SCRD	T	BW FLG	G	SCRD	G	SCRD

Table 6-3 Legend for Table 6-2

Type		Ends	
B	Ball	WFR	Wafer or Lug Wafer
G	Gate	FLG	Flanged
T	Globe	BW	Butt Welded
Y	Y-Pattern Globe	SW	Socket Welded
P	Plug	SCRD	Threaded
F	Butterfly	P-FIT	Victaulic Press Fit
NA	Not Applicable	BR	Brazed

6.1.3 Coatings

External Coatings

External coatings are described in Table 6-4 by equipment type and design temperature.

Table 6-4 External Coating Descriptions

Section	Description	Design Temp (°F)	Coating System
1.0	Pipe and Pipe Supports		
1.1	Carbon Steel		
1.1.1	Uninsulated	≤200	Epoxy (EPS)/ Epoxy (EPS)/ Polyurethane (URA)
1.1.2		>200 ≤1,000	Inorganic Zinc (IZ)/ Silicone Acrylic (SLA)
1.1.3	Insulated	>25 <350	Epoxy Phenolic (EPP)/ Epoxy Phenolic (EPP)
1.1.4		>300 (>149)	Alkyd (ALK) [NOTE 1]
1.2	Stainless Steel		
1.2.1	Uninsulated	All	No coating
1.2.2	Insulated	>120 <350	Epoxy Phenolic (EPP)/ Epoxy Phenolic (EPP) [NOTE 2]
1.2.3		>350 <120	No coating
2.0	Tanks, Drums, Columns, Vessels, Reactors, and Shell and Tube Heat Exchangers - Shop Fabricated		
2.1	Carbon Steel		
2.1.1	Uninsulated	≤200	Epoxy Zinc (EPZ)/ Epoxy (EPS)/ Polyurethane (URA)
2.1.2		>200 ≤1,000	Inorganic Zinc (IZ)/ Silicone Acrylic (SLA)
2.1.3	Insulated	>25 <350	Epoxy Phenolic (EPP)/ Epoxy Phenolic (EPP)
2.1.4		>350	Alkyd (ALK) [NOTE 1]
2.2	Stainless Steel		
2.2.1	Uninsulated	All	No Coating
2.2.2	Insulated	>120 <350	Epoxy Phenolic (EPP)/Epoxy Phenolic (EPP) [NOTE 2]
2.2.3		>350 <120	No Coating
3.0	Bulk Valves, Fittings, Pumps, Compressors, Rotating Equipment, and Other Mechanical Equipment Not Specified Otherwise	All	Q301 Manufacturer's Standard Coating for the intended ISO 12944 C4 environment.

Notes:
1. Alkyd (ALK) coating is provided for short-term corrosion protection during shipping, storage, and construction. No coating is required if the time interval between shipment and startup is less than 24 months.
2. Applicable to 18-8 austenitic stainless steels, e.g., 304 and 316, and duplex stainless steels. Coating is not required for higher alloyed materials.

Internal Coatings

Internal coatings and cleaning requirements are described in Table 6-5 by system/process type.

Table 6-5 Internal Coatings and Cleaning Methods

System Name	Piping Fabrication Cleaning Method (1)	Post-Fabrication Preservative or Coating Option (2)	Post-Installation Cleaning (3,4,5)
Fuel Gas	SP6 – Commercial Blast Cleaning	1001- Vapor phase corrosion inhibitor (water soluble preservative)	Pigging (below grade) Air Blow (above grade)
Digester Gas	No special cleaning required	None	Air Blow
Waste Water	No special cleaning required	None	Service Water Flush
Waste Water (U/G)	No special cleaning required	None	Service Water Flush
Compressed Air (Station Air)	No special cleaning required	None	Air Blow
Instrument Air	No special cleaning required (SS) SP6- Commercial Blast Cleaning (CS)	None (SS) Vapor phase corrosion inhibitor (water soluble preservative) (CS)	Air Blow
Nitrogen	No special cleaning required	None	Air Blow
Carbon Dioxide	No special cleaning required	None	Air Blow
Service Water	SP3 – Power Tool Cleaning	None	Service Water Flush
Fire Protection	No special cleaning required	None	Fire Water Flush

Notes:
Piping Fabrication Cleaning Methods:
NO- no special cleaning required.
SP3- Power tool cleaning.
SP6- Commercial blast cleaning.
SP8- Pickled.
WJ1- Water jetting in the field to sp-12, wj1 cleanliness.

Post-Fabrication Piping Preservative or Coating Options:
1001 – vapor phase corrosions inhibitor (water soluble preservative).
1002- oil soluble preservative.
2314- epoxy coal tar.
CP- coating prohibited.
NONE – manufacturer's standard coating system or no internal coating require.
Service water and demineralized water flushes should be performed with treated water as defined by the guide.

System Name	Piping Fabrication Cleaning Method (1)	Post-Fabrication Preservative or Coating Option (2)	Post-Installation Cleaning (3,4,5)
Hydro blasting may be an appropriated alternative to chemical cleaning and steam blowing for certain applications, depending on piping length and accessibility. Air blow post-installation cleaning should be performed with clean, dry air.			

6.1.4 Insulation, Jacketing, and Lagging

Insulation and lagging will be applied to equipment, piping, valves, specialties, and ductwork as shown in Table 6-6. Insulation material for piping will be mineral fiber (Type II, per ASTM C547), and jacketing material will be stucco-embossed aluminum. A minimum jacketing thickness of 0.016 inch will be used. Insulation and lagging will be designed for conditions of 75° F ambient, emissivity of 0.09, no incident solar heating, and 2 mph airflow velocity, for a normal operating calculated surface temperature of 150° F using the method defined in ASTM Standard C680. For pipe and equipment with an operating temperature of 600° F or higher, two layers of insulation with fully staggered offset joints/seams will be used.

Table 6-6 Insulation and Lagging Requirements

Max. Op. Temp.	Nominal Insulation Thickness (in.) vs. Nominal Pipe Diameter (in.)										
	0.50	**0.75**	**1.00**	**1.25**	**2.00**	**2.50**	**3.00**	**4.00**	**6.00**	**8.00**	
1,000	2.00	2.50	2.50	3.00	3.00	3.00	3.50	4.00	4.50	4.50	
800	1.50	1.50	1.50	1.50	2.00	2.00	2.50	2.50	3.00	3.00	
600	1.00	1.00	1.00	1.00	1.50	1.50	1.50	1.50	2.00	2.00	
500	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.50	1.50	
400	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
300	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
200	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Max. Op. Temp.	**Nominal Insulation Thickness (in.) vs. Nominal Pipe Diameter (in.)**										
	10.00	**12.00**	**14.00**	**16.00**	**18.00**	**20.00**	**22.00**	**24.00**	**30.00**	**36.00**	**48.00**
1,000	5.00	5.50	5.50	6.00	6.00	6.00	6.00	6.50	6.50	7.00	7.50
800	3.50	3.50	3.50	4.00	4.00	4.00	4.00	4.00	4.50	4.50	5.00
600	2.00	2.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	3.00	3.00
500	1.50	1.50	1.50	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
400	1.00	1.00	1.00	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
300	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
200	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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The following specific situations may deviate from the above guidelines:

- Pipe, tubing, and valves over 150° F, but that are not accessible (not within seven feet vertically or three feet horizontally) to personnel during normal operations and that do not require heat loss prevention, need not be insulated. Examples are hot drain piping, vent stacks, vents, compressed air and gas lines, sulfur trioxide lines, and similar items selected by Black & Veatch.
- Anti-sweat insulation shall be applied to piping, equipment, and ductwork where ambient and process temperature creates a potential for condensation on the exterior surface.
- Piping, tubing, instruments, and equipment requiring freeze protection as indicated in Section 6.1.5.

6.1.5 Freeze Protection

Freeze protection design criteria are shown in Table 6-7.

Table 6-7 Freeze Protection Design Criteria

Main Design Criteria	
Minimum Ambient Temperature	20 °F
Wind Speed	19.1 mph
Maximum Pipe Radius Frozen	10%
Acceptable Time to Freeze (Plant operators must drain stagnant piping systems within this time frame)	8 hours
Electric Heat Tracing Criteria (Liquid Service Piping Exposed to Freezing Conditions)	
≤2-inch NPS	None
≥ 2-1/2-inch NPS	None

6.1.6 Process Temperature Maintenance

Refer to 6.1.4 for minimum insulation thickness based on operating temperature. Heat or steam tracing is not required for any process piping temperature maintenance.

6.1.7 Space Conditioning

Space conditioning is only expected to be required for new electrical/control system buildings.

6.1.8 Fire Protection

The fire protection review, and hazard assessment will be conducted once the layout of new equipment has been further developed. At that time, modifications or additions to the existing plant fire protection system and/or equipment will be further defined and reflected in this document.

7.0 Electrical Design Basis

7.1 DESIGN CRIERTIA

7.1.1 Electrical Power Available at Battery Limits

The new plant electrical system design is dictated by the local utility distribution source available and the plant electrical loads. The system voltage levels and design shall be according to the project one-line diagram and the below.

- MV Distribution 4.16kV, 60Hz, 3-Phase (Not currently envisioned).
- LV Distribution 480V, 60Hz, 3-Phase.

7.1.2 Electric Motors

Motors shall be purchased with the driven equipment, and be in accordance with NEMA MG1 and the following:

- MV Motors: 4000V, 250HP and larger, 1.0 service factor, class B temp rise, class F insulation.
- LV Motors: 460V, ½ to 249HP, 1.0 service factor, class B temp rise, class F insulation.
- Single-Phase Motors: 120V, Up to 1/3 HP.

7.1.3 Uninterruptible Power Supply, Battery Systems, and Emergency Power

Critical plant ac and dc loads will be powered from an uninterruptible power system (UPS) or battery system. The UPS will power items such as DCS, programmable logic controllers (PLCs), network equipment, and critical instruments and equipment. The battery system will power items such as switchgear relays and operational power, UPS, and critical motors.

The DC battery and UPS will be provided as follows:

- Duty Cycle: 2 hours.
- DC Battery: 125VDC.
- UPS: 120VAC, 1-phase.

An emergency generation system will serve emergency power if required to safely shut down the facility.

7.1.4 Classification of Hazardous Areas

Hazardous area classification is determined by the Electrical Project Discipline Engineer, according to NFPA and other applicable codes. The Mechanical Project Discipline Engineer is responsible for space control and life safety issues. This will be addressed once equipment layout has been determined.

7.1.5 Grounding

The plant grounding system will follow the recommendations of the NEC.

- Bare copper grounding conductor insulated where installed in conduit.
- Copper-clad, ¾ inch x 10-foot section ground rods.
- Exothermic junction bonding method.

7.1.6 Lightning Protection

The plant is in a location of relatively low number of thunderstorm days per year, however, lightning protection will be provided on any new large buildings. The system will consist of air terminals, interconnecting conductors, down conductors with connection to the grounding system, and bonding of metal objects on or within the structure. Conductors shall be copper.

7.1.7 Lighting

Lighting systems shall be as follows:

- Office, control room, and electrical rooms shall be LED.
- Indoor high bay, outdoor platforms, outdoor above doors, hazardous areas, and any roadway lighting shall be high-pressure sodium.
- Emergency lighting shall be provided for egress utilizing integral fixture battery packs.
- Outdoor lighting shall be controlled by photoelectric controllers and control switch.

7.1.8 Wiring and Raceways

Ampacities of cable in cable tray are based on NFPA-70 (NEC). The following cable types may be grouped in common cable trays with other cables of the same type:

- Medium voltage cables.
- 600-volt power cable.
- Control cables.
- Instrument analog.
- Cable construction shall be as shown in Table 7-1.

Table 7-1 Cable Construction

Voltage Level/Application	Minimum Cable Construction
Medium Voltage Power	1/c EPR insulation, copper tape- shielded, FR-PVC jacket, 133% insulation
Low Voltage Power	1/c FR-XLPE insulation without jacket (RHH/RHW-2/USE-2) or 3/c XLPE or EPR insulation, FR- PVC jacket
Low Voltage Control	XLPE or EPR insulation, FR-PVC jacket
Instrument - 300 V	PVC or PVC/Nylon insulation, FR- PVC jacket
Instrument Thermocouple Extension Wire - 300 V	PVC insulation, FR-PVC jacket
Grounding	Bare conductor or 1/c THHN/THWN, green insulation
Lighting - Interior at 120 V	1/c THHN/THWN insulation
Lighting - Exterior and interior greater than 120 V	1/c XHHW-2 insulation
Note: Special application cables are not listed.	

Raceway materials shall be as shown in Table 7-2:

Table 7-2 Raceway Materials

Raceway System	Material/Construction
Duct Bank (horizontal runs)	PVC Schedule 40 RGS (when required for shielding)

	2-inch separation between tubes
Duct Bank Risers (all tubes including elbows)	RGS
Cable Tray - Ladder	Aluminum
Cable Tray (wet or corrosive areas)	Aluminum or fiberglass
Conduit (general purpose)	
Conduit	RGS
Lighting and Communication Circuits (indoors, nonhazardous locations)	EMT
Circuits (outdoors, hazardous locations)	RGS
Direct Buried PVC (underground)	PVC Schedule 40
Conduit Fittings	RGS - Malleable iron

7.1.9 Plant Communication

A plantwide communication or paging system will not be provided and will rely on handheld radios for any required communication between personnel.

7.1.10 Electrical Freeze Protection and Temperature Maintenance

Piping freeze protection and temperature maintenance systems may be required for outdoor piping, instruments, and equipment devices subject to cold weather. In the cases where it is needed, heat trace control panels and respective power transformers will be provided in strategic areas to serve this need. Refer to section 6.0 Mechanical Design Basis for further information.

Appendix C. Site Visit Memorandum

BLACK & VEATCH

MEMORANDUM

Pacific Gas and Electric Company (PG&E)	B&V Project Number 401616
Monterey Park Tract (MPT) Gas Microgrid Support	B&V File Number 40.3100
Trinkler Dairy Site Visit	29 March 2019

To: Jamie Randolph, Principal Interconnection Manager, PG&E
From: Jim Easterly, Project Manager, Black & Veatch

Address:
Trinkler Farm
7251 Crows Landing Road
Ceres, CA 95307

Contact
Jon Rebiero, Trinkler Dairy Farms, Inc.
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Site Visit Participants
Jamie Randolph, Principal Interconnection Manager (PG&E)
Mary Diebert, Account Manager (PG&E)
Joerg Blischke, Senior Process and Organics Management Specialist (B&V)
Matthew Prather, Environmental Regulatory Licensing Specialist (B&V)

Site Description
The Trinkler Dairy Farm is located at 7251 Crows Landing Road, at the southwest corner of the Crows Landing and West Taylor Roads intersection, west of the City of Ceres in Stanislaus County, CA. The MPT residential subdivision is located approximately 650 feet west of the site's southwestern property line.

The site includes:
- Four homes
- Dairy facility structures
  - Animal barns (milking cows, dry cows, heifers and calves)
  - Milk barn
  - Ancillary equipment
- Groundwater wells
- Backup generator
- Propane tank
- Feed storage (covered and outdoors)
- Mechanical screening and overs storage
- Two wastewater lagoons

Synopsis of Information Obtained during Site Visit

Animal head count

- Approximately 1,500 milking cows
- Approximately 1,500 non-milking cows (dry cows, heifers and calves)
- Farm applied for and received use permit from Stanislaus County for doubling the number of milking cows in their operation, but are not sure at the moment when expansion will start
- Consensus was reached by site visit attendees that the MPT Gas Microgrid Project will use the current animal headcount for the basis of design

Liquid Stream Management

- Manure management
    - Pens are flushed with recycled water from wastewater storage lagoon #2 (WWSL2) throughout the year
    - In the summer months (Jun/Jul/Aug) water flushing demand is supplemented with well water of up to 50% by volume
    - The flushing cycle for the different barn/pan areas is timer controlled; on an 8-hr cycle
    - Each pen is flushed twice a day
    - Flushed wastewater from the pens are routed by gravity to two sumps, which are controlled by float switches; the output from these pumps is feed through two outdoor elevated screens (installed in parallel) for course material (mostly fiber) removal
        - Screen overs are removed via a moving belt scraper and discharged by gravity onto the paved floor below
        - Screen overs are used as farm crop fertilizer, applied twice a year (Spring and Fall)
        - Farm is considering using material for animal bedding in the future
    - Centrate/filtrate is routed by gravity via pipes into wastewater storage lagoon #1 (WWSL1)
    - Current screen size is not known; Trinkler had tested with smaller screen size to recover more fibers but smaller screens were prone to plugging
    - Current screen has been in operation for the last 5 years without known operational issues
    - Wastewater from WWSL1 can be routed via overflow weir or transfer pump to WWSL2
    - Normal transfer operation: transfer pump from WWSL1 to WWSL2 is operated at the same time as the WWSL2 discharge pump for pen flushing to maintain equilibrium between the two lagoons
    - Location of WWSL2 sump pump for flushing is not clear; either on NW corner of WWSL2 or mounted on floating pontoon towers in the NW lagoon area
    - WWSL2 capacity appears to be almost double the capacity of WWSL1
    - Amount of produced manure, qualities of flushing water used (recycled and well) and overall flow to WWSL1 lagoon were not provided during the site visit
    - WWSL1 (and possibly WWSL2) cleaning schedule is once or twice per year

  - Trinkler has not previously experienced a lagoon overflow/spillage event; when wastewater liquid level is moving to a critical level then wastewater from WWSL2 is used for field irrigation
  - The capacities of the transfer and recycle pump are 600 gpm each
  - Characterization of manure (and recycled flush water): no lab data available on characteristics of wastewater feeding the screen nor centrate/filtrate sent to WWLS1; the Waste Management Plan (or Nutrient Management Plan) may contain data on the characteristics of the WWLS2 effluent
  - Asked if the Farm would consider or has considered switching from flush to scrape manure operation: not at this time, as it would require additional investments for equipment plus increases labor (biggest issue)
- Milk parlor
  - Milking cows are milked twice a day
  - Floor flushed/cleaned with well water; discharged to the sump feeding WWSL1
  - Amount of water for flushing was not known during site visit
- Stormwater management
  - Rain water from roof of barns are collected in gutter and routed to the sump feeding WWSL1
  - Rainwater and any other water for cleaning/flushing of the paved area is routed to a low-point catch basin from where an in-ground pipe is connected to one of the manure collection sumps (flow by gravity into sump)

Permitting
- Jon confirmed that the site is covered under the Regional Water Quality Control Board Dairy General Permit for wastewater
- Farm received approval of application from Stanislaus County for expansion of the project via use permit and has a good relationship with the county and surrounding community
- Farm received San Joaquin Valley Air Pollution Control District Approval for expansion
- Site must begin construction or submit for an extension by the end of the 2019

Utilities
- One propane tank is used for heating process water to support the dairy operation
- One back-up diesel-fueled generator
- Power feed for facility:
  - From power pole and line entering the property from Crows Landing Road running West
  - Another power line runs along W. Taylor Road (East-West axis); one of the irrigation pumps fed from the surface water supply ditch for field irrigation is connected to this line
  - Another sump pump on the WWSL2 discharge site (for recycled water; on the NW corner of WWSL2) is connected to this power line as well.
  - Jon was not aware of any specific capacity constraints with respect to utilities

Other Information

- Available land for new digester: east of WWSL2
- Possible/preferred location for CNG upgrading and fueling station: west or southwest of WWSL2; access via dirt road off Taylor Rd. running South
- Discussed various new digester implementation and operation options; Jon appears to prefer having the digester and biogas upgrading complex be operated by a third party, but this may change as the project evolves
- Jon is not aware of any odor complaints from adjacent neighbors
- Geotechnical information: Jon was not aware of any boring and soil analysis for the Farm; some geotechnical information may be found in the application for Use Permit for Dairy Operation expansion that may include the addition of a WWSL
- Dairy Farm objective for this project: reduce methane emissions from the dairy operation appears to be a key motivator
- Willingness of adjacent farms to transport their manure to Trinkler for disposition via anaerobic digestion (AD) and interactions with other AD developers
    - Did not discuss this topic specifically, but Mary mentioned that PG&E had reached out to other adjacent dairies with little traction
    - Jon had only initial discussions with another AD project developer about a year ago but couldn't recall the name

Follow-up Information Request for Trinkler Farms

- Animal population count/type
- Bedding material type
- Location of WWSL2 sump pump for flushing
- Drawings for storage lagoon design and capacity
- Trinkler Waste Management Plan

Appendix D. Mass and Energy Balance

CLIENT: PGE
PROJECT NAME: MPT Gas Microgrid
PROJECT NUMBER: 401616
CASE: Summer
LOCATION: Ceres, CA
Rev B

AtchA-87

CASE: Summer											
STREAM NUMBER		1	2	3	4	5	6	7	8	9	10
STREAM DESCRIPTION		Raw Manure and Bedding from Barn	Recycled Water from WWSL2 to Barn	Well Water to Parlor	Parlor Wastewater	Combined Flow from Barns to Fiber Recovery	Separated Solids / Recovered Fiber	Influent to Digester	Rainwater to WWSL2	Effluent from WWSL2 to Irrigation	AD Process Loss
STREAM PROPERTIES											
Temperature	F	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	100.0
Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
	psig	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mass Flowrate	lb/hr	9,121	91,210	9,408	9,759	110,091	2,960	107,130	56,262	71,666	26
Volumetric Flowrate at T & P	ft3/hr	146.4	1,461.7	150.8	156.4	1,764.5	47.4	1,716.8	901.6	1,148.5	409.5
Phase		Liquid / Solid	Liquid	Liquid	Liquid	Liquid	Liquid / Solid	Liquid	Liquid	Liquid	Gas
VAPOR PROPERTIES											
Mass Flowrate	lb/hr	NA	NA	NA	NA	NA	NA	NA	NA	NA	26
Volumetric Flowrate at T & P	ft3/hr	NA	NA	NA	NA	NA	NA	NA	NA	NA	409.5
Volumetric Flowrate at STP	ft3/min	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.4
Density	lb/ft3	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.067
Heat Capacity	Btu/lb-F	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.415
LIQUID PROPERTIES											
Mass Flowrate	lb/hr	9,121	91,210	9,408	9,759	110,091	2,960	107,130	56,262	71,666	NA
Volumetric Flowrate at T & P	ft3/hr	146.4	1,461.7	150.8	156.4	1,764.5	47.4	1,716.8	901.6	1,148.5	NA
Density	lb/ft3	62.3	62.4	62.4	62.4	62.4	62.5	62.4	62.4	62.4	NA
Heat Capacity	Btu/lb-F	NA	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	NA
COMPOSITION, lb/hr	**MW**										
Water	18.016	7,781.71	90,754.36	9,407.75	9,690.63	108,226.70	2,309.10	105,917.59	56,261.90	71,307.78	0.11
Manure TS	NA	1,339.34	456.05	0.00	68.69	1,864.08	651.29	1,212.79	0.00	358.33	NA
Manure VS	NA	1,144.45	250.83	0.00	58.69	1,453.97	488.46	965.51	0.00	197.08	NA
Methane	16.043	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.63
Carbon Dioxide	44.011	NA	NA	NA	NA	NA	NA	NA	NA	NA	14.27
Nitrogen	28.014	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.54
Oxygen	32.000	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.16
Hydrogen Sulfide	34.076	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.07
Carbon Monoxide	28.011	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NO2	46.006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Sulfur Dioxide	64.064	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
VOCs	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total		9,121.04	91,210.42	9,407.75	9,759.32	110,090.77	2,960.39	107,130.38	56,261.90	71,666.11	25.79

AtchA-88

CASE: Summer											
STREAM NUMBER		11	12	13	14	15	16	17	18	19	20
STREAM DESCRIPTION		Digestate from Digester to WWSL2	Raw Biogas to Compression	Compressed Dry Biogas to Cleaning System	Biogas Condensate to Digester	Biogas Cleaning System Off-Gas to Thermal Oxidizer	Thermal Oxidizer Emissions	RNG to PoR	RNG from PoR	RNG to Local/Trinkler Vehicles	RNG to MPT
STREAM PROPERTIES											
Temperature	F	80.0	100.0	40.0	40.0	100.0	1,200.0	100.0	100.0	100.0	100.0
Pressure	psia	14.7	14.7	214.7	14.7	15.7	14.7	3,614.7	3,614.7	3,614.7	3,614.7
	psig	0.0	0.0	200.0	0.0	1.0	0.0	3,600.0	3,600.0	3,600.0	3,600.0
Mass Flowrate	lb/hr	106,615	490	487	2	280	385	208	206	35	7
Volumetric Flowrate at T & P	ft3/hr	1,708.6	7,782.6	480.3	0.0	2,575.8	NA	20.7	20.5	3.4	0.7
Phase		Liquid	Gas	Gas	Liquid	Gas	Gas	Gas	Gas	Gas	Gas
VAPOR PROPERTIES											
Mass Flowrate	lb/hr	NA	490	487	NA	280	385	208	206	35	7
Volumetric Flowrate at T & P	ft3/hr	NA	7,782.6	480.3	NA	2,575.8	NA	20.7	20.5	3.4	0.7
Volumetric Flowrate at STP	ft3/min	NA	122.3	120.7	NA	43.2	NA	80.0	79.2	13.3	2.5
Density	lb/ft3	NA	0.067	1.013	NA	0.109	NA	10.025	10.025	10.025	10.025
Heat Capacity	Btu/lb-F	NA	0.415	0.415	NA	0.23	NA	0.527	0.527	0.527	0.527
LIQUID PROPERTIES											
Mass Flowrate	lb/hr	106,615	NA	NA	2	NA	NA	NA	NA	NA	NA
Volumetric Flowrate at T & P	ft3/hr	1,708.6	NA	NA	0.0	NA	NA	NA	NA	NA	NA
Density	lb/ft3	62.4	NA	NA	62.4	NA	NA	NA	NA	NA	NA
Heat Capacity	Btu/lb-F	1.00	NA	NA	1.00	NA	NA	NA	NA	NA	NA
COMPOSITION, lb/hr	MW										
Water	18.016	105,915.39	2.09	0.00	2.09	0.00	NA	0.00	0.00	0.00	0.00
Manure TS	NA	697.04	NA	NA	NA	NA	NA	NA	NA	NA	NA
Manure VS	NA	449.76	NA	NA	NA	NA	NA	NA	NA	NA	NA
Methane	16.043	NA	202.01	202.01	NA	10.10	NA	191.91	189.99	31.97	6.09
Carbon Dioxide	44.011	NA	271.13	271.13	NA	266.12	382.36	5.00	4.95	0.83	0.16
Nitrogen	28.014	NA	10.31	10.31	NA	0.00	NA	10.31	10.21	1.72	0.33
Oxygen	32.000	NA	3.10	3.10	NA	2.73	NA	0.37	0.37	0.06	0.01
Hydrogen Sulfide	34.076	NA	1.32	0.00	NA	1.32	NA	NA	NA	NA	NA
Carbon Monoxide	28.011	NA	NA	NA	NA	NA	0.02	NA	NA	NA	NA
NO2	46.006	NA	NA	NA	NA	NA	0.06	NA	NA	NA	NA
Sulfur Dioxide	64.064	NA	NA	NA	NA	NA	2.48	NA	NA	NA	NA
VOCs	NA	NA	NA	NA	NA	NA	0.39	NA	NA	NA	NA
Total		106,612.43	489.96	486.55	2.09	280.27	385.32	207.60	205.52	34.58	6.59

CASE: Summer		
STREAM NUMBER		21
STREAM DESCRIPTION		RNG to Tube Trailers
STREAM PROPERTIES		
Temperature	F	100.0
Pressure	psia	3,614.7
	psig	3,600.0
Mass Flowrate	lb/hr	164
Volumetric Flowrate at T & P	ft3/hr	16.4
Phase		Gas
VAPOR PROPERTIES		
Mass Flowrate	lb/hr	164
Volumetric Flowrate at T & P	ft3/hr	16.4
Volumetric Flowrate at STP	ft3/min	63.4
Density	lb/ft3	10.025
Heat Capacity	Btu/lb-F	0.527
LIQUID PROPERTIES		
Mass Flowrate	lb/hr	NA
Volumetric Flowrate at T & P	ft3/hr	NA
Density	lb/ft3	NA
Heat Capacity	Btu/lb-F	NA
COMPOSITION, lb/hr	**MW**	
Water	18.016	0.00
Manure TS	NA	NA
Manure VS	NA	NA
Methane	16.043	151.93
Carbon Dioxide	44.011	3.96
Nitrogen	28.014	8.16
Oxygen	32.000	0.29
Hydrogen Sulfide	34.076	NA
Carbon Monoxide	28.011	NA
NO2	46.006	NA
Sulfur Dioxide	64.064	NA
VOCs	NA	NA
Total		164.35

AtchA-89

CLIENT: PGE
PROJECT NAME: MPT Gas Microgrid
PROJECT NUMBER: 401616
CASE: Winter
LOCATION: Ceres, CA
Rev B

CASE: Winter

STREAM NUMBER		1	2	3	4	5	6	7	8	9	10
STREAM DESCRIPTION		Raw Manure and Bedding from Barn	Recycled Water from WWSL2 to Barn	Well Water to Parlor	Parlor Wastewater	Combined Flow from Barns to Fiber Recovery	Separated Solids / Recovered Fiber	Influent to Digester	Rainwater to WWSL2	Effluent from WWSL2 to Irrigation	AD Process Loss
STREAM PROPERTIES											
Temperature	F	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	70.0
Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
	psig	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mass Flowrate	lb/hr	11,348	113,476	9,408	9,877	134,700	3,622	131,078	56,262	73,379	24
Volumetric Flowrate at T & P	ft3/hr	182.2	1,818.5	150.8	158.3	2,159.0	58.0	2,100.6	901.6	1,175.9	364.7
Phase		Liquid / Solid	Liquid	Liquid	Liquid	Liquid	Liquid / Solid	Liquid	Liquid	Liquid	Gas
VAPOR PROPERTIES											
Mass Flowrate	lb/hr	NA	NA	NA	NA	NA	NA	NA	NA	NA	24
Volumetric Flowrate at T & P	ft3/hr	NA	NA	NA	NA	NA	NA	NA	NA	NA	364.7
Volumetric Flowrate at STP	ft3/min	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.1
Density	lb/ft3	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.067
Heat Capacity	Btu/lb-F	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.415
LIQUID PROPERTIES											
Mass Flowrate	lb/hr	11,348	113,476	9,408	9,877	134,700	3,622	131,078	56,262	73,379	NA
Volumetric Flowrate at T & P	ft3/hr	182.2	1,818.5	150.8	158.3	2,159.0	58.0	2,100.6	901.6	1,175.9	NA
Density	lb/ft3	62.3	62.4	62.4	62.4	62.4	62.5	62.4	62.4	62.4	NA
Heat Capacity	Btu/lb-F	NA	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	NA
COMPOSITION, lb/hr	**MW**										
Water	18.016	9,681.32	112,908.66	9,407.75	9,790.81	132,380.79	2,825.28	129,555.51	56,261.90	73,011.62	0.10
Manure TS	NA	1,666.29	567.38	0.00	85.70	2,319.36	796.87	1,522.49	0.00	366.89	NA
Manure VS	NA	1,423.82	312.06	0.00	73.23	1,809.11	597.65	1,211.46	0.00	201.79	NA
Methane	16.043	NA	NA	NA	NA	NA	NA	NA	NA	NA	10.01
Carbon Dioxide	44.011	NA	NA	NA	NA	NA	NA	NA	NA	NA	13.43
Nitrogen	28.014	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.51
Oxygen	32.000	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.15
Hydrogen Sulfide	34.076	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.07
Carbon Monoxide	28.011	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NO2	46.006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Sulfur Dioxide	64.064	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
VOCs	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total		11,347.60	113,476.04	9,407.75	9,876.50	134,700.15	3,622.15	131,078.00	56,261.90	73,378.51	24.27

AtchA-90

CASE: Winter

STREAM NUMBER		11	12	13	14	15	16	17	18	19	20
STREAM DESCRIPTION		Digestate from Digester to WWSL2	Raw Biogas to Compression	Compressed Dry Biogas to Cleaning System	Biogas Condensate to Digester	Biogas Cleaning System Off-Gas to Thermal Oxidizer	Thermal Oxidizer Emissions	RNG to PoR	RNG from PoR	RNG to Local/Trinkler Vehicles	RNG to MPT
STREAM PROPERTIES											
Temperature	F	50.0	70.0	40.0	40.0	100.0	1,200.0	100.0	100.0	100.0	100.0
Pressure	psia	14.7	14.7	214.7	14.7	15.7	14.7	3,614.7	3,614.7	3,614.7	3,614.7
	psig	0.0	0.0	200.0	0.0	1.0	0.0	3,600.0	3,600.0	3,600.0	3,600.0
Mass Flowrate	lb/hr	130,593	461	458	2	264	368	195	193	35	7
Volumetric Flowrate at T & P	ft3/hr	2,092.8	6,931.5	452.0	0.0	2,424.0	NA	19.5	19.3	3.4	0.7
Phase		Liquid	Gas	Gas	Liquid	Gas	Gas	Gas	Gas	Gas	Gas
VAPOR PROPERTIES											
Mass Flowrate	lb/hr	NA	461	458	NA	264	368	195	193	35	7
Volumetric Flowrate at T & P	ft3/hr	NA	6,931.5	452.0	NA	2,424.0	NA	19.5	19.3	3.4	0.7
Volumetric Flowrate at STP	ft3/min	NA	115.1	113.4	NA	40.7	NA	75.3	74.6	13.3	2.5
Density	lb/ft3	NA	0.067	1.013	NA	0.109	NA	10.025	10.025	10.025	10.025
Heat Capacity	Btu/lb-F	NA	0.415	0.415	NA	0.23	NA	0.527	0.527	0.527	0.527
LIQUID PROPERTIES											
Mass Flowrate	lb/hr	130,593	NA	NA	2	NA	NA	NA	NA	NA	NA
Volumetric Flowrate at T & P	ft3/hr	2,092.8	NA	NA	0.0	NA	NA	NA	NA	NA	NA
Density	lb/ft3	62.4	NA	NA	62.4	NA	NA	NA	NA	NA	NA
Heat Capacity	Btu/lb-F	1.00	NA	NA	1.00	NA	NA	NA	NA	NA	NA
COMPOSITION, lb/hr	**MW**										
Water	18.016	129,553.44	1.97	0.00	1.97	0.00	NA	0.00	0.00	0.00	0.00
Manure TS	NA	1,037.14	NA	NA	NA	NA	NA	NA	NA	NA	NA
Manure VS	NA	726.11	NA	NA	NA	NA	NA	NA	NA	NA	NA
Methane	16.043	NA	190.10	190.10	NA	9.51	NA	180.60	178.79	31.97	6.09
Carbon Dioxide	44.011	NA	255.14	255.14	NA	250.44	365.06	4.71	4.66	0.83	0.16
Nitrogen	28.014	NA	9.70	9.70	NA	0.00	NA	9.70	9.61	1.72	0.33
Oxygen	32.000	NA	2.92	2.92	NA	2.57	NA	0.35	0.35	0.06	0.01
Hydrogen Sulfide	34.076	NA	1.24	0.00	NA	1.24	NA	NA	NA	NA	NA
Carbon Monoxide	28.011	NA	NA	NA	NA	NA	0.02	NA	NA	NA	NA
NO2	46.006	NA	NA	NA	NA	NA	0.06	NA	NA	NA	NA
Sulfur Dioxide	64.064	NA	NA	NA	NA	NA	2.33	NA	NA	NA	NA
VOCs	NA	NA	NA	NA	NA	NA	0.38	NA	NA	NA	NA
Total		130,590.58	461.08	457.87	1.97	263.75	367.85	195.36	193.41	34.58	6.59

AtchA-91

CLIENT: PGE
PROJECT NAME: MPT Gas Microgrid
PROJECT NUMBER: 401616
CASE: Winter
LOCATION: Ceres, CA
Rev B

CASE: Winter		
STREAM NUMBER		21
STREAM DESCRIPTION		RNG to Tube Trailers
STREAM PROPERTIES		
Temperature	F	100.0
Pressure	psia	3,614.7
	psig	3,600.0
Mass Flowrate	lb/hr	152
Volumetric Flowrate at T & P	ft3/hr	15.2
Phase		Gas
VAPOR PROPERTIES		
Mass Flowrate	lb/hr	152
Volumetric Flowrate at T & P	ft3/hr	15.2
Volumetric Flowrate at STP	ft3/min	58.7
Density	lb/ft3	10.025
Heat Capacity	Btu/lb-F	0.527
LIQUID PROPERTIES		
Mass Flowrate	lb/hr	NA
Volumetric Flowrate at T & P	ft3/hr	NA
Density	lb/ft3	NA
Heat Capacity	Btu/lb-F	NA
COMPOSITION, lb/hr	MW	
Water	18.016	0.00
Manure TS	NA	NA
Manure VS	NA	NA
Methane	16.043	140.73
Carbon Dioxide	44.011	3.67
Nitrogen	28.014	7.56
Oxygen	32.000	0.27
Hydrogen Sulfide	34.076	NA
Carbon Monoxide	28.011	NA
NO2	46.006	NA
Sulfur Dioxide	64.064	NA
VOCs	NA	NA
Total		152.23

AtchA-92

Appendix E. Process Flow Diagram

010-SU-0001 WASHDOWN SUMP (EXISTING)

010-P-0001 WASHDOWN PUMP (EXISTING)

010-FL-0001 SOLIDS REMOVAL SCREEN (EXISTING)

010-R-0001 LAGOON DIGESTER PLUS LINER

010-R-0002 LAGOON DIGESTER COVER

010-TK-0001 LAGOON ACCUMULATION TANK

010-P-0004 A/B RAIN WATER SUMP PUMP

010-U-0001 WASTEWATER STORAGE LAGOON #1 (EXISTING)

010-P-0002 WASTEWATER TRANSFER PUMP (EXISTING)

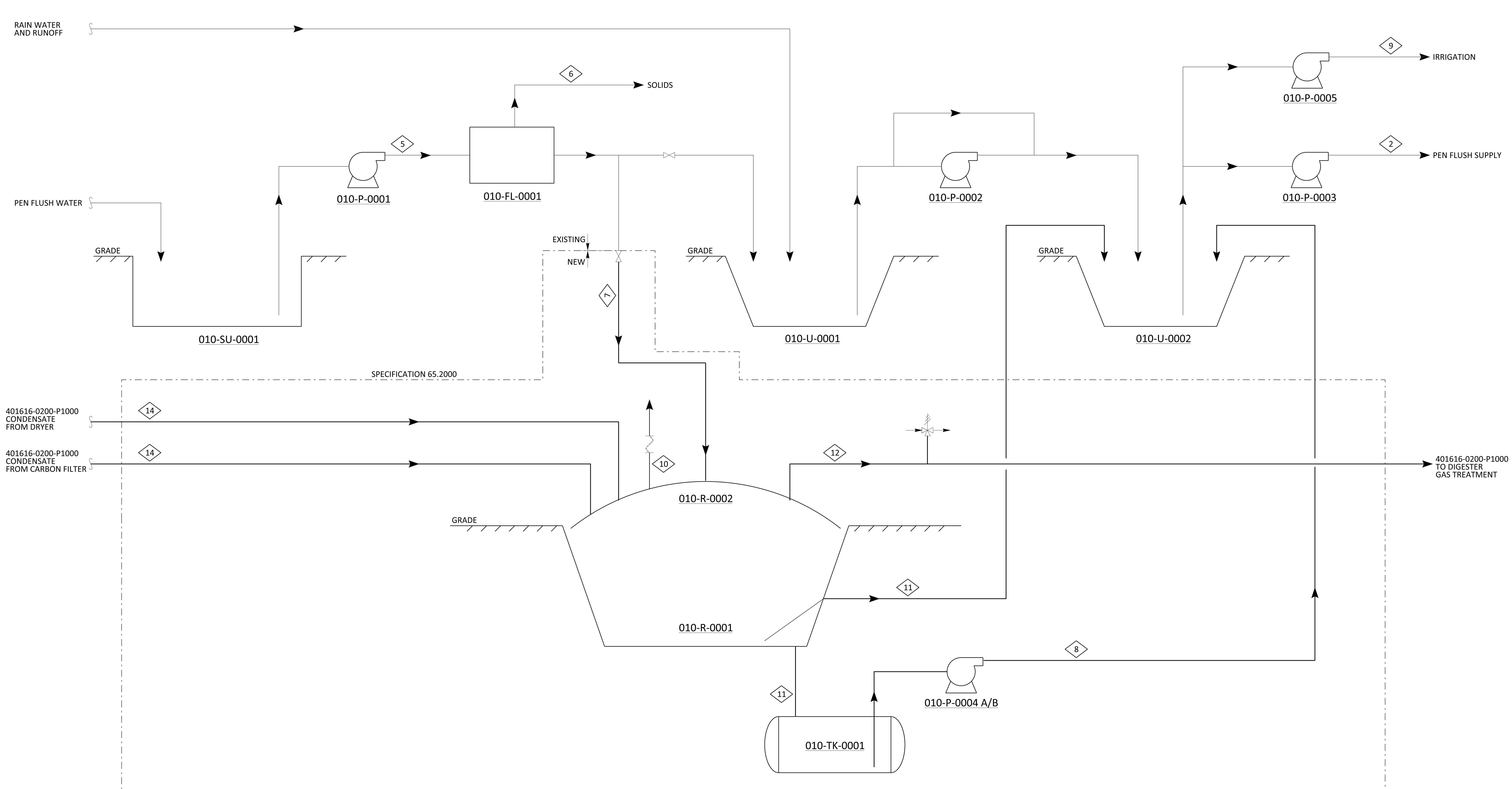
010-U-0002 WASTEWATER STORAGE LAGOON #2 (EXISTING)

010-P-0003 WASTEWATER RECYCLE PUMP (EXISTING)

010-P-0005 WASTEWATER IRRIGATION PUMP (EXISTING)

NOTES

1. EACH PEN IS FLUSHED TWO TIMES PER DAY.
2. IN JUNE, JULY & AUGUST FLUSH WATER IS SUPPLEMENTED WITH WELL WATER OF UP TO 50% BY VOLUME.
3. THE FLUSHING CYCLE FOR THE DIFFERENT BARN/PEN AREAS IS ON AN 8-HOUR CONTROLLED TIMER.



LEGEND

NEW

EXISTING

STREAM NUMBER

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
B	4/23/2019	ISSUED FOR RFQ	RJB	ODH	MCH	MCH	JMC
A	4/10/2019	ISSUED FOR CLIENT REVIEW	RJB	ODH	MCH	MCH	JMC

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF CALIFORNIA

SIGNED

DATE REG NO.

BLACK & VEATCH

DESIGNER ODH | DRAWN RJB

CHECKED MCH | DATE

PACIFIC GAS & ELECTRIC

MONTEREY PARK TRACT GAS MICROGRID SUPPORT

PROCESS FLOW DIAGRAM

ANAEROBIC DIGESTION

PROJECT | DRAWING NUMBER: 401616-0100-P1000 | REV: B

CODE

AREA

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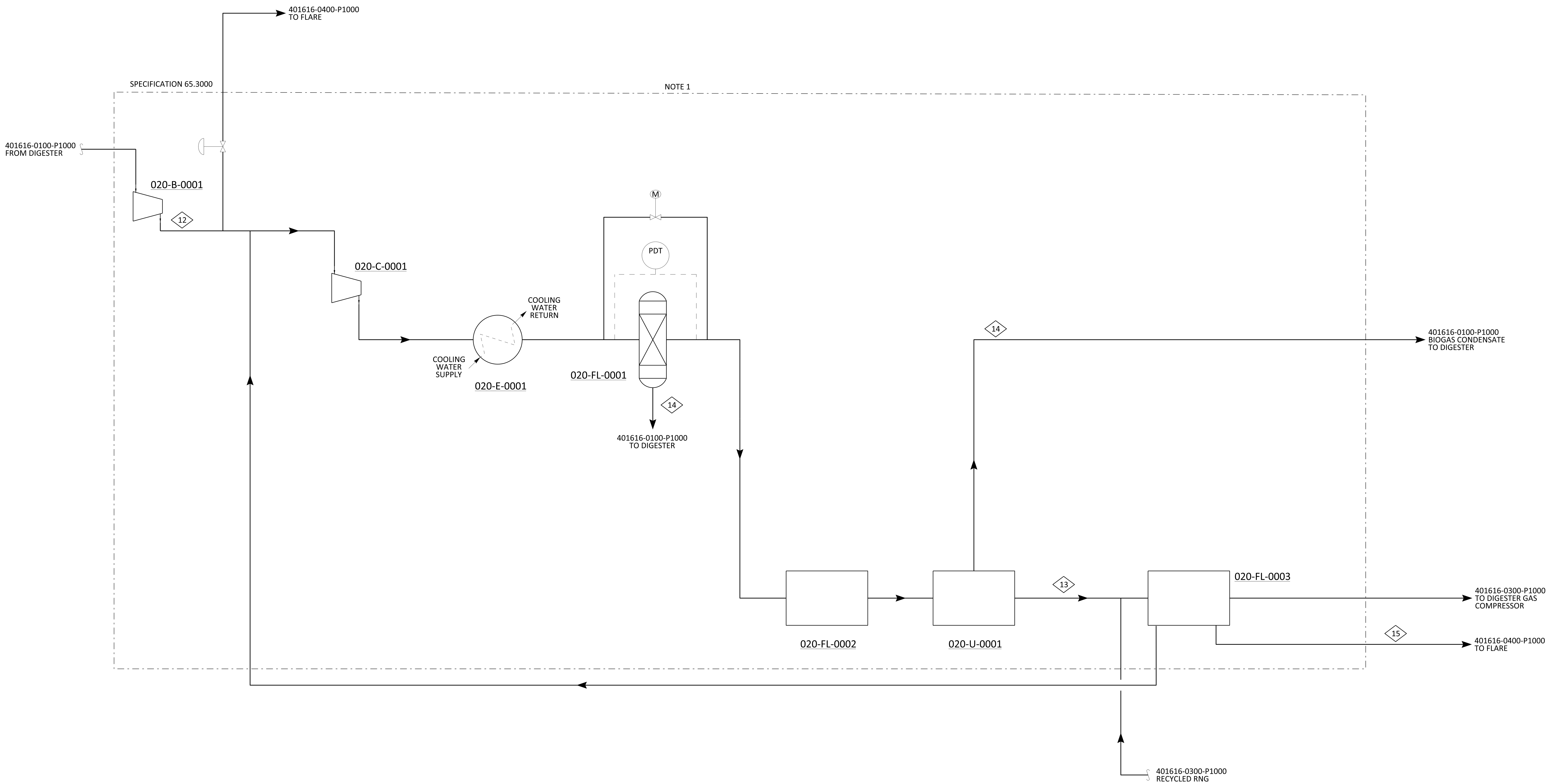
020-B-0001	020-F-0001	020-C-0001	020-E-0001	020-FL-0001	020-FL-0002	020-U-0001	020-FL-0003
DIGESTER GAS BLOWER	FLARE	DIGESTER GAS FEED COMPRESSOR	DIGESTER GAS AFTER-COOLER	DIGESTER PRETREATMENT FILTER	H2S REMOVAL	DRYER	MEMBRANE GAS SEPARATION

NOTES:

1. FINAL CONFIGURATION TO BE CONFIRMED UPON PURCHASE OF EQUIPMENT



LEGEND

NEW

EXISTING

STREAM NUMBER

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C	5/6/2019	CLIENT/VENDOR REVIEW REVISION	ODH	ODH	MCH	MCH	JMC
B	4/23/2019	ISSUED FOR RFQ	RJB	ODH	MCH	MCH	JMC
A	4/10/2019	ISSUED FOR CLIENT REVIEW	RJB	ODH	MCH	MCH	JMC

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PACIFIC GAS & ELECTRIC
MONTEREY PARK TRACT GAS MICROGRID SUPPORT

PROCESS FLOW DIAGRAM
DIGESTER GAS TREATMENT

PROJECT | DRAWING NUMBER 401616-0200-P1000 | REV C

CODE

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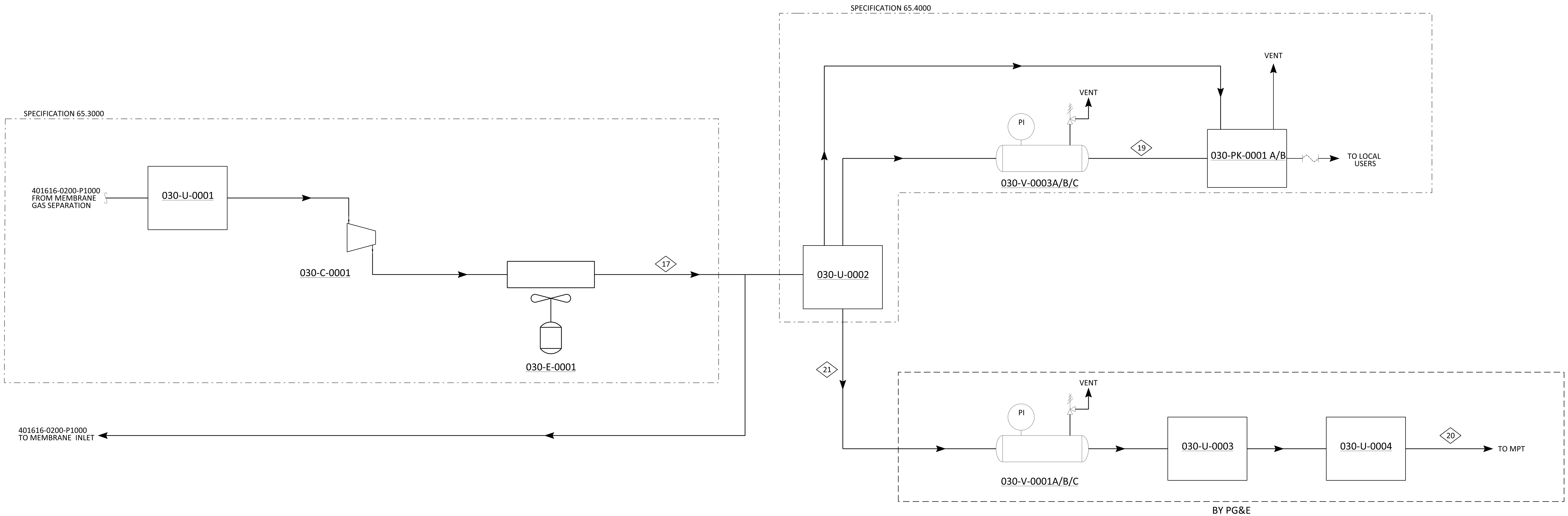
POINT OF RECEIPT AND ODORIZATION	RNG COMPRESSOR	RNG AFTER-COOLER	PRIORITY PANEL	TUBE TRAILER	DISPENSER STORAGE VESSEL	RNG DISPENSER	HIGH/LO PSI REGULATION & HEAT EXCHANGE	MONTEREY PARK TRACT INTERCONNECT TO DISTRIBUTION PIPELINE



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B	4/23/2019	ISSUED FOR RFQ	RJB	ODH	MCH	MCH	JMC
A	4/10/2019	ISSUED FOR CLIENT REVIEW	RJB	ODH	MCH	MCH	JMC

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DATE

PACIFIC GAS & ELECTRIC
MONTEREY PARK TRACT GAS MICROGRID SUPPORT

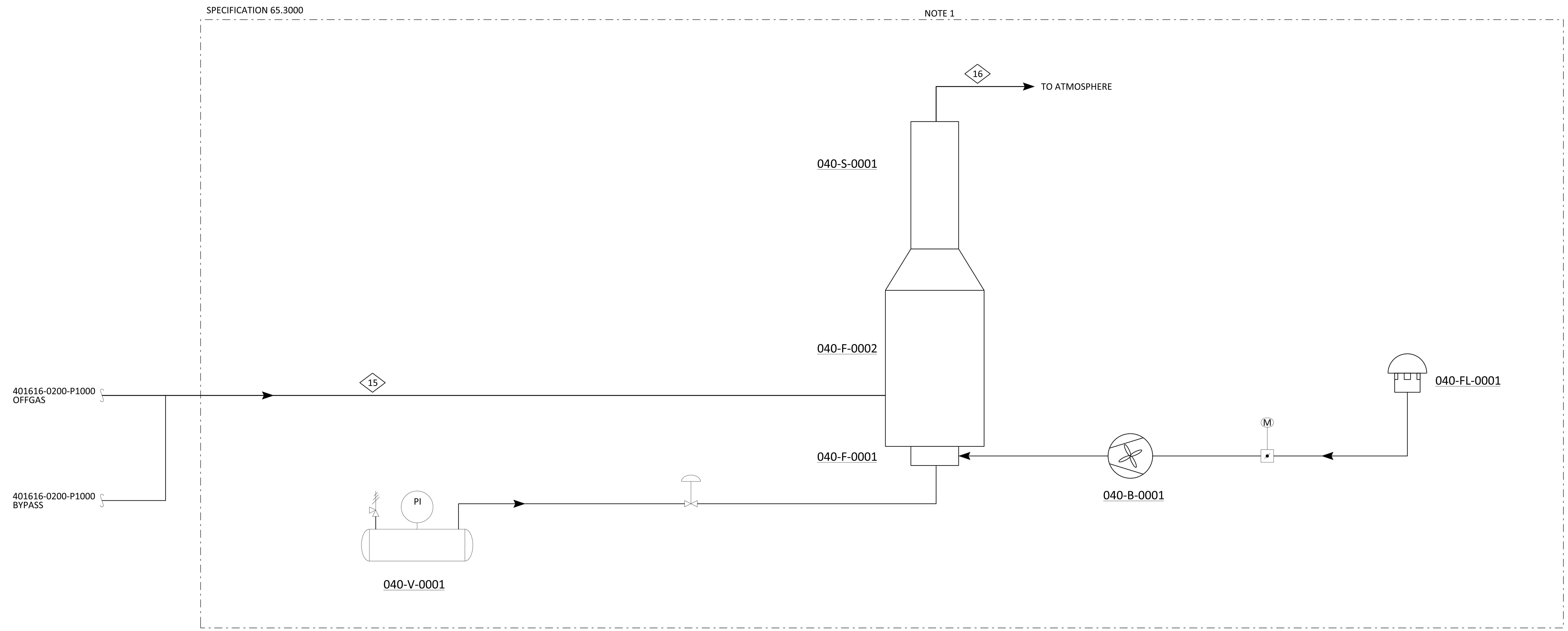
PROCESS FLOW DIAGRAM
DIGESTER GAS COMPRESSION

PROJECT
DRAWING NUMBER 401616-0300-P1000
REV C
CODE
AREA

040-V-0001	040-F-0001	040-F-0002	040-S-0001	040-B-0001	040-FL-0001
PROPANE STORAGE	FLARE BURNER	FLARE	STACK	FLARE FAN	INLET AIR FILTER

NOTES:

1. FLARE PACKAGE CONTENTS TO BE CONFIRMED SUBJECT TO FINAL PROCUREMENT. CONTENTS TO BE COMPLIANT WITH APPLICABLE EMISSION LAWS



LEGEND

NEW
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STREAM NUMBER

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C	5/6/2019	CLIENT/VENDOR REVIEW REVISIONS	ODH	ODH	MCH	MCH	JMC
B	4/23/2019	ISSUED FOR RFQ	RJB	ODH	MCH	MCH	JMC
A	4/10/2019	ISSUED FOR CLIENT REVIEW	RJB	ODH	MCH	MCH	JMC

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PACIFIC GAS & ELECTRIC
MONTEREY PARK TRACT GAS MICROGRID SUPPORT

PROCESS FLOW DIAGRAM
FLARE

PROJECT | DRAWING NUMBER 401616-0400-P1000 | REV C

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Appendix F. Equipment List

EQUIPMENT LIST

B&V PROJECT NO. 401616

NO	DATE	REVISIONS AND RECORDS OF ISSUE	DRN	DES	CHK	PDE	APP
D	5/6/2019	CLIENT/VENDOR REVIEW REVISIONS	ODH	ODH	MCH	MCH	JMC
C	4/23/2019	ISSUED FOR RFP	ODH	ODH	MCH	MCH	JMC
B	4/22/2019	ISSUED FOR IHR	ODH	ODH	MCH	MCH	JMC
A	4/19/2019	ISSUED FOR CLIENT REVIEW	ODH	ODH	MCH	MCH	JMC

NO	DATE	REVISIONS AND RECORDS OF ISSUE	DRN	DES	CHK	PDE	APP

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BLACK & VEATCH CORPORATION

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MCH	ODH
CHECKED	DATE
MCH	4/19/2019

PACIFIC GAS & ELECTRIC

MONTEREY PARK TRACT GAS MICROGRID SUPPORT

EQUIPMENT LIST

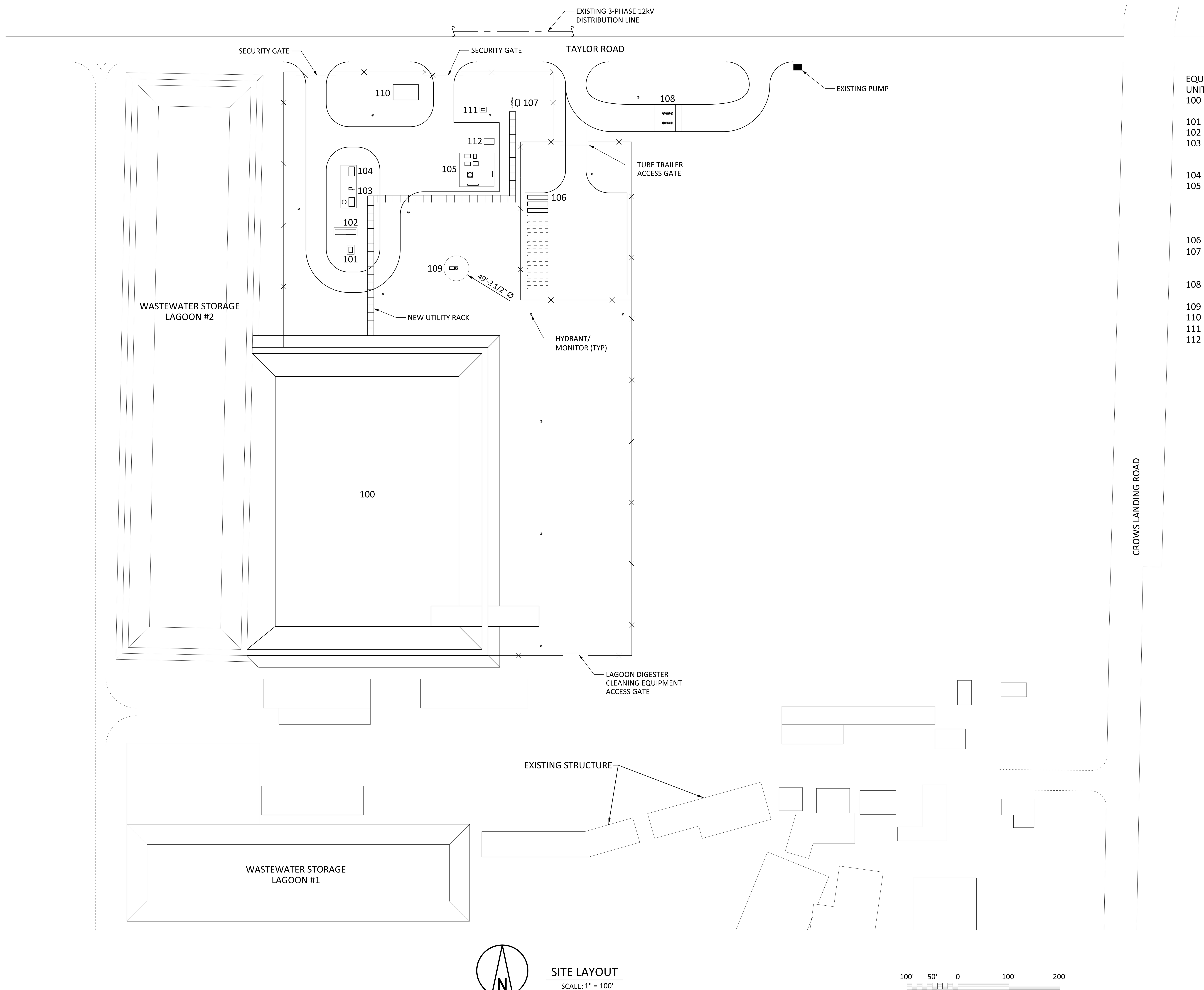
PROJECT DRAWING NUMBER: 401616 -0000-P0101

REV: D

CLIENT REV

Area	Prefix	Train	Seq.	Tag	Equipment Name	Quantity	Type	Capacity/Duty	Size	Design Pressure (psig)	Design Temperature (°F)	Materials of Construction	Supplier	Notes
				Vessels & Filters										
010	FL	0	001	010-FL-0001	Solids Removal Screen	1	Horizontal						Existing	
020	FL	0	001	020-FL-0001	Digester Pretreatment Filter	1	Vertical	108.9 - 122.3 SCFM		200	90			
020	FL	0	002	020-FL-0002	H_2S Removal	1	Vertical	108.9 - 122.3 SCFM	8' x 17' (L x H)	200	90			
020	FL	0	003	020-FL-0003	Membrane Gas Separation	1	Vertical	108.9 - 122.3 SCFM	18' x 11' W x 12' H (L x W x H)	200	90			
030	V	0	001	030-V-0001A/B/C	Tube Trailer	3	Horizontal	363,148 SCF	40' x 8' x 8' (L x W x H)	3,600	90		By PG&E	
030	V	0	003	030-V-0003A/B/C	Dispenser Storage Vessel	3	Horizontal	11,571 SCF	23' x 20 " (L x D)	3,600	90			
040	V	0	001	040-V-0001	Propane Storage	1	Horizontal							
040	FL	0	001	040-FL-0001	Inlet Air Filter	1	Vertical							
010	TK	0	001	010-TK-0001	Lagoon Accumulation Tank	1	Below Grade	15,000 GAL	120"x25.5' (DIAxL)	25	0			
				Fired & Reactor Equipment										
010	R	0	001	010-R-0001	Lagoon Digester Plus Liner	1	Anaerobic Digester	2,750,514 ft^3	580' x 450' (L x W)	2 " w.c	113			
010	R	0	002	010-R-0002	Lagoon Digester Cover	1	Anaerobic Digester		580' x 450' (L x W)	2 " w.c	113			
040	F	0	001	040-F-0001	Flare Burner	1	Burner	108.9 - 122.3 SCFM			1832			
040	F	0	002	040-F-0002	Flare	1	Ground	108.9 - 122.3 SCFM	6' x 8' x 26'		1832			
				Heat Exchangers										
020	E	0	001	020-E-0001	Digester Gas LP After-cooler	1	Shell & Tube	84,148 BTU/hr	Shell ID = 5.42" Area = 18.1 ft^2	Shell: 150 Tube: 200	Shell: 150 Tube: 510			Gas Side Flow Rate = 108.9 - 122.3 SCFM
030	E	0	001	030-E-0001	RNG After-cooler	1	Air- Cooled	62,000 BTU/hr	25 HP					Gas Side Flow Rate = 75.2 - 80.2 SCFM
				Rotating Equipment										
010	P	0	001	010-P-0001	Washdown Sump Pump	1							Existing	
010	P	0	002	010-P-0002	Wastewater Transfer Pump	1		600 GPM					Existing	
010	P	0	003	010-P-0003	Wastewater Recycle Pump	1		600 GPM					Existing	
010	P	0	005	010-P-0005	Wastewater Irrigation Pump	1		600 GPM					Existing	
010	P	0	004	010-P-0004A/B	Rain Water Sump Pump	2	Centrifugal	170 GPM	6 HP	150	120			
020	P	0	001	020-P-0001A/B	Fire Water Pump	2	Centrifugal	2400 GPM	100 HP	150	120			
020	C	0	001	020-C-0001	Digester Gas Feed Compressor	1	Centrifugal	108.9 - 122.3 SCFM	31 HP	Inlet: 2" w.c Outlet: 200 psig	510			
030	C	0	001	030-C-0001	RNG Gas Compressor	1	Centrifugal	75.2 - 80.2 SCFM	60 HP	Inlet: 200 psig Outlet: 3600 psig	550			
020	B	0	001	020-B-0001	Digester Gas Blower	1	Centrifugal	108.9 - 122.3 SCFM	4.6 HP	Inlet: 2" w.c Outlet: 10 psig				
040	B	0	001	040-B-0001	Flare Fan	1			11 kW					
				Packaged Equipment & Miscellaneous										
010	SU	0	001	010-SU-0001	Washdown Sump	1							Existing	
010	U	0	001	010-U-0001	Wastewater Storage Lagoon #1	1		900,973 ft^3	640' x 175' x 12'				Existing	
010	U	0	002	010-U-0002	Wastewater Storage Lagoon #2	1		2,028,492 ft^3	1075' x 215' x 13'				Existing	
020	U	0	001	020-U-0001	Dryer	1		108.9 - 122.3 SCFM		200	90			
030	U	0	001	030-U-0001	Point of Receipt and Odorization	1				200	90			
030	U	0	002	030-U-0002	Priority Panel	1				3,600	90			
030	U	0	003	030-U-0003	High/Lo PSI Regulation & Heat Exchange	1							By PG&E	
030	U	0	004	030-U-0004	MPT Interconnect to Distribution Pipeline	1							By PG&E	
030	PK	0	001	030-PK-0001A/B	RNG Dispenser	2	CNG	up to 5,000 SCFM	48" x 93" x 29" (WxHxD)	3,600	90			m. = 35 lbm/hr @ 3600 psig
040	S	0	001	040-S-0001	Stack	1	Stack							
030	U	0	002	030-U-0002	Dispenser Canopy	1	Canopy		53' x 53' x 20' (W x L x H)					

Appendix G. General Arrangement Drawing



SITE LAYOUT
SCALE: 1" = 100'

100' 50' 0 100' 200'
1"=100'

EQUIPMENT LIST

UNIT #	EQUIPMENT #	DESCRIPTION
100	010-R-0001	LAGOON DIGESTER
	010-R-0002	LAGOON DIGESTER COVER
101	020-C-0001	DIGESTER GAS FEED COMPRESSOR
102	020-E-0001	DIGESTER GAS AFTER-COOLER
103	020-FL-0001	DIGESTER GAS CARBON FILTER
	020-FL-0002	H2S REMOVAL
	020-U-0001	DRYER
104	020-FL-0003	MEMBRANE GAS SEPARATION
105	030-U-0001	POINT OF RECEIPT AND ODORIZATION
	030-C-0001	RNG COMPRESSOR
	030-E-0001	DIGESTER GAS AFTER-COOLER
	030-U-0002	PRIORITY PANEL
	030-V-0003A/B/C	RNG DISPENSER STORAGE TANK A/B/C
106	030-V-0001A/B/C	TUBE TRAILERS
107	030-U-0003	HIGH/LO PSI REG. & HEAT EXCHANGE
	030-U-0004	MONTEREY PARK TRACT INTERCONNECT TO DISTRIBUTION PIPELINE
108	030-PK-0001A/B	RNG DISPENSER A/B
	030-U-0002	DISPENSER CANOPY
109	040-F-0002	FLARE
110	020-P-0001A/B	FIRE PUMP A/B
111	030-XF-0001	MAIN PADMOUNT TRANSFORMER
112	030-BD-0001	ELECTRICAL PDC

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C	5/9/2019	CLIENT/VENDOR REVIEW REVISIONS	RJB	RJB		MCH	
B	4/23/2019	ISSUED FOR RFQ	RJB	RJB		MCH	
A	4/19/2019	ISSUED FOR CLIENT REVIEW	RJB	RJB		MCH	

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DRAWN RJB
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DATE

PACIFIC GAS & ELECTRIC
MONTEREY PARK TRACT GAS MICROGRID SUPPORT

GENERAL ARRANGEMENT
OVERALL SITE LAYOUT

PROJECT 401616-0000-G2000 DRAWING NUMBER
REV C
CODE
AREA

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1"=1" Full Size
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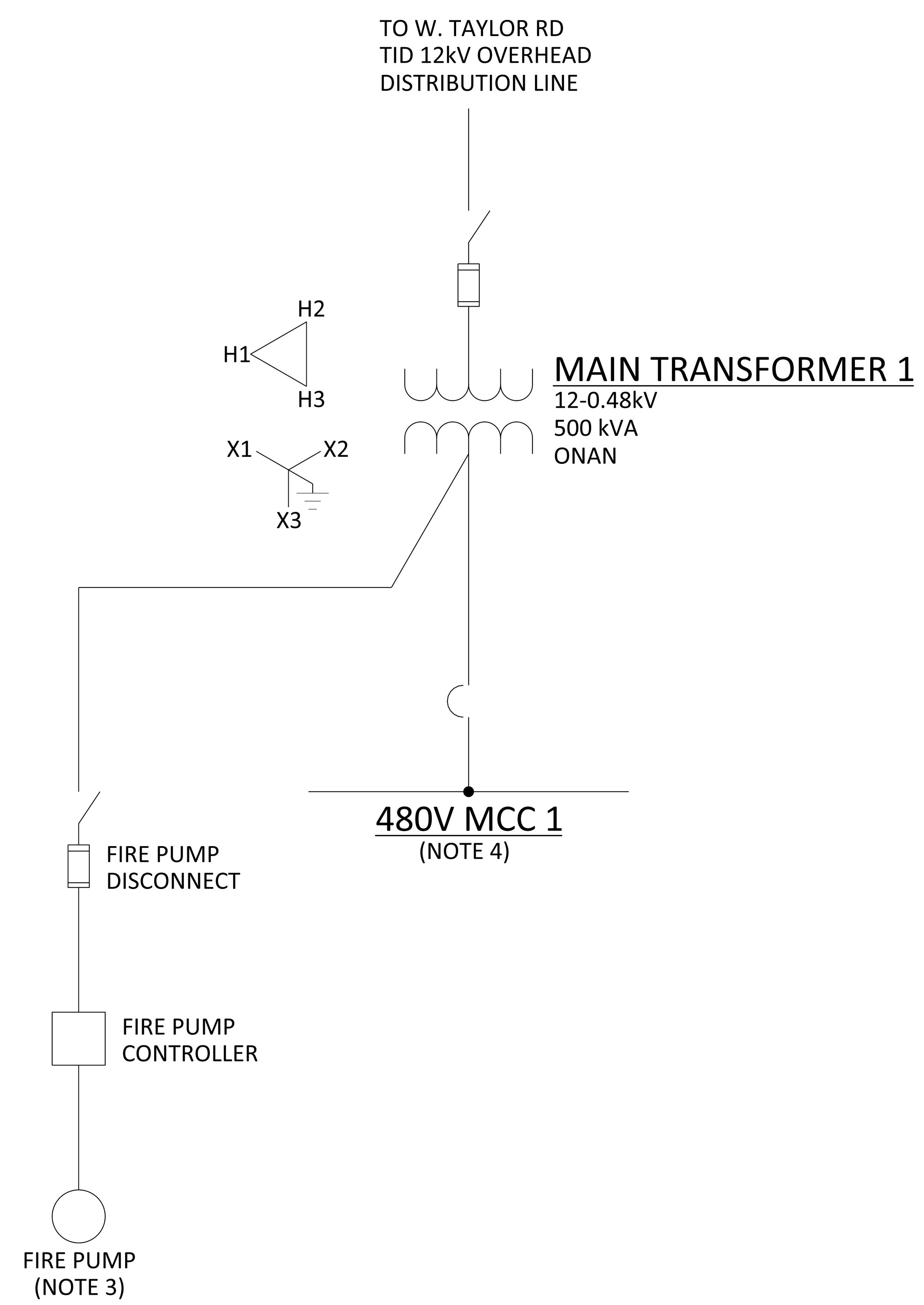
Appendix H. One-Line Diagram



NOTES:

1. THE EQUIPMENT RATINGS AND CONFIGURATION SHOWN ARE PRELIMINARY AND SUBJECT TO CHANGE DURING DETAILED DESIGN.
2. EXISTING DAIRY FARM LOADS ARE NOT SHOWN ON THIS ONE-LINE. REFER TO PROJECT EQUIPMENT LIST.
3. SITE INCLUDES 1-100% DIESEL DRIVEN FIRE PUMP AND 1-100% ELECTRICAL MOTOR DRIVEN FIRE PUMP.
4. 480V MOTOR CONTROL CENTER FEEDS PLANT ELECTRICAL LOADS INCLUDING PUMPS, LIGHTING, HVAC, ETC. REFER TO PROJECT LOAD LISTING FOR FURTHER DETAILS.

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B	05/08/19	ISSUED FOR FINAL REPORT	DCT	JSL		JSL	
A	04/25/19	ISSUED FOR CLIENT REVIEW	ALC	JSL		JSL	

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PACIFIC GAS & ELECTRIC

MONTEREY PARK TRACT GAS MICROGRID SUPPORT

CONCEPTUAL OVERALL ONE-LINE DIAGRAM

PROJECT | DRAWING NUMBER 401616-1000-E1000 | REV B

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Appendix I. Permitting Matrix

Table I-1 Specific Environmental Permitting Requirements

AGENCY	PERMIT/ APPROVAL	REGULATED ACTIVITY	REQUIRED PROJECT PHASE	REQUIRED FOR PROJECT	EXPECTED/ TYPICAL REVIEW TIME	COMMENTS
FEDERAL						
EPA	SPCC Plan	Temporary onsite fuel and/or oil storage	Construction/ Operation	Yes	N/A	Construction contractor will be required to generate a SPCC Plan for construction activities. Once operation begins, the SPCC Plan will need to be updated or redrafted to reflect operating details for the facility.
EPA	TRI Reporting under EPCRA	Release of toxic emissions	Construction/ Operation	Likely	N/A	Reporting requirements triggered by storage/handling of toxic chemicals (EPCRA Section 313) above threshold limits.
EPA	TIER II Reporting under EPCRA	Toxic and hazardous chemical use and storage	Construction/ Operation	Likely	N/A	Identify whether storage of toxic chemicals will be required for construction and operation. Methane may trigger reporting.
STATE						
Lead Agency- Stanislaus County	CEQA Review	Land use and development in the state of California	Construction	Yes	6-18 months	If the project may cause either a direct or indirect impact to the environment and would require the issuance of a permit by one or more public agency, it will be considered a “project” under CEQA and will be subject to review
CEPA – Central Valley Water Resources Control Board	NPDES General Storm Water Construction Permit	Discharge of storm water from construction sites impacting one or more acres	Construction	Yes	2-3 months	Triggered by disturbance of one or more acres during construction Coverage available under Construction General Permit Order 2009-0009-DWQ. This permit will be obtained from the appropriate Regional Water Board.
CEPA – Central Valley Water Resources Control Board	Waste Discharge Requirements General Order for Dairy Farms with manure Anaerobic Digesters or Co-Digester Facilities	Waste water discharges from operations.	Operation	Yes	6-12 months	This permit is required for dairy farm facilities with manure anaerobic digesters or co-digesters that discharge waste water.
CEPA – Central Valley Water Resources Control Board	Water Use Permit/ Approval	Extraction and use of water	Operation	Possible	6-12 months	The type of permit or approval will depend on the final design of the facility and water source. Once those decisions are made, Black & Veatch can assist in determining what agency needs to issue the appropriate approval/permit.
CalTrans	Transportation/ Heavy Haul Permits	Transportation of oversized or overweight loads along state highways	Construction	Likely	2-3 months	May be required, depending on shipping methods used by the project
CDRRR	Solid Waste Facilities Permit	Constructing a new anaerobic digester	Construction	Possible	3-6 months	Although the CDRRR is responsible for approving permits, each permit is processed and issued by a Local Enforcement Agency (LEA). The LEA is the primary contact for the regulation of solid waste handling, processing or disposal activities, including permitting requirements. To determine whether a permit is required for any proposed facility, each potential operator should contact the appropriate county LEA and work with them directly regarding the applicability of regulatory requirements.

AGENCY	PERMIT/ APPROVAL	REGULATED ACTIVITY	REQUIRED PROJECT PHASE	REQUIRED FOR PROJECT	EXPECTED/ TYPICAL REVIEW TIME	COMMENTS
Air Requirements – San Joaquin Valley Air Pollution Control District (SJVAPCD)						
SJVAPCD	Authority to Construct (ATC)	Construction of Air Contaminant Sources	Pre - Construction	Yes	Likely 3-6 months if not held up by CEQA review. Review period may exceed this timeline if the project triggers major source permitting.	An ATC will be required for each new emission source prior to construction. It is likely that the digester equipment, biogas conditioning equipment, and RNG refueling equipment will be treated as a facility separate from the existing dairy farm (i.e. permitted as a separate facility) due to the processes falling under different Standard Industrial Classification (SIC) codes. BACT required for any source that causes an increase in emissions of an air contaminant greater than 2 lb/day. New Source Review (NSR) major source permitting is triggered for projects emitting NO_X and VOCs in excess of 10 tons per year (tpy), CO in excess of 100 tpy, PM10, PM2.5 and SO_X in excess of 70 tpy which may result in more stringent emission limit requirements and lengthier permit processing time. The potential emissions from the new equipment would need to exceed 10 tpy for NO_X /VOCs, 27.38 tpy for SO_X, 14.6 tpy for PM10 & 100 tpy for CO to trigger the requirement to obtain offsets. Emergency equipment used exclusively as emergency standby equipment that does not operate more than 200 hours per year may be exempt from obtaining emissions offsets. An ambient air quality analysis including air dispersion modeling required for installation of any new emissions source. This analysis will be conducted by the Technical Services Division of the SJVAPCD. Toxics BACT is required if the cancer risk exceeds one in one million. The project may be required to undergo a Health Risk Assessment formed by the Technical Services Division of the SJVAPCD.
SJVAPCD	Permit to Operate (PTO)	Operation of Air Contaminant Sources	Operation	Yes	Agency drafts and issues permit for facilities below Title V thresholds upon verification Project was constructed according to parameters of ATC (separate application for PTO not required in this case). If triggered, initial Title V permit application due within 12 months of initial operation.	A PTO will be required for each new emission source. All PTOs required to be renewed every five years. Title V Permit to Operate required for Major Sources (i.e. sources with a PTE in excess of 10 tpy for NO_X & VOCs, 100 tpy for CO & PM2.5, 70 tpy for PM10 & SO_X and/or emissions of a single hazardous air pollutant (HAP) > 10 tpy, and/or cumulative HAPs emissions > 25 tpy).
LOCAL						
Stanislaus County Planning Department	Conditional Use Permit	Required in some counties for a change in zoning to allow for construction of digester or gasifier	Construction	Yes	6-9 months	A Conditional Use Permit will be required by Stanislaus County for the RNG production and distribution facility. The issuance of a Conditional Use Permit includes a CEQA Review. A modification to the existing Use Permit may be obtained with further consultation with Stanislaus County once final design and operation parameters are established.

AGENCY	PERMIT/ APPROVAL	REGULATED ACTIVITY	REQUIRED PROJECT PHASE	REQUIRED FOR PROJECT	EXPECTED/ TYPICAL REVIEW TIME	COMMENTS
Stanislaus County Public Works Department	Building Permit	New construction	Construction	Yes	1-2 months	Will depend on final site location. This permit is representative of the majority of the US
Stanislaus County Public Works Department	Encroachment Permit	Construction activities and new connections to county roads	Construction	Possible	1-2 months	Will depend on final site location. This permit is representative of the majority of the US
Stanislaus County Planning Department	Grading Permit	Grading or clearing activities	Construction	Possible	1-2 months	Will depend on final site location. This permit is representative of the majority of the US
Fire Marshall	Fire Code Permit	Compliance with fire code	Construction	Yes	1-2 months	Will depend on final site location. This permit is representative of the majority of the US

Appendix J. Vendor Request for Quotation Packages

01100 - Technical Scope and Performance Requirements

01100.1 Technical Scope of Work

The work under these specifications shall include furnishing the following:

Black & Veatch is assisting with the design and development of a renewable natural gas (RNG) Production and Distribution Facility. The following stream numbers refer to the process streams shown in the attached mass balance. The new covered lagoon digester will receive a flushed manure stream from dairy cows (stream 7) and anaerobically digest the manure to produce biogas (stream 12). Biogas will be captured and cleaned to RNG downstream by a separate scope of supply. The project site is located approximately eight miles south of Modesto in the town of Ceres, CA, which is in the San Joaquin Valley (SJV). The site has access via well maintained secondary roads. Major transportation links in the vicinity include California Route 99 to the east and California Route 33 / Interstate 5 to the west.

Site-Specific Design Criteria

Design Barometric Pressure:	14.66 psia [NOTE 1]
Elevation:	73 ft
Design Minimum Ambient Temperature:	20 °F [NOTE 1]
Design Maximum Ambient Temperature (dry bulb):	113.6 °F [NOTE 1]
Design Maximum Ambient Temperature (wet bulb):	79.3 °F [NOTE 1]
NOTES 1. Based on ASHRAE HVAC design data for 724926 weather station.	

Refer to Article 01100.2.1 for attachments detailing the process information. The attachments include the following to identify required process inlet and outlet conditions: process flow diagrams of the systems, mass balances with the stream conditions of each process flow. The scope of this package shall begin at the influent to the digester (stream 7) and end at the captured digester gas to gas treatment (stream 12). The supplier’s scope should account for condensate inflow to the digester (stream 14) and digestate outflow to an adjacent wastewater storage lagoon (WWSL) (stream 11). The supplier shall provide a complete engineered package that accepts the defined conditions outlined below. Rainfall onto the digester cover shall be designed to accumulate in the lagoon accumulation tank. The tank will be pumped out and the flow will be routed to an adjacent storage lagoon. The digester shall be designed with an access ramp to allow for heavy equipment to enter the digester for periodic maintenance.

Design Basis Parameters

Condition	Value
Total Liquid Volume (ft^3)	2,751,000
Hydraulic Retention Time (days)	55
Organic Loading rate (lb_m VS/1000 ft^3-day)	10 – 10.5
Digester Length (ft)	580
Digester Width (ft)	450
Digester Depth (ft)	15
Freeboard (ft)	2
Side Slopes	3:1

Major Equipment Scope			
Item	**Description**	**Tag Number(s)**	**Quantity**
1.	Lagoon Digester Plus Liner	010-R-0001	1
2.	Lagoon Digester Cover	010-R-0002	1
3.	Lagoon Accumulation Tank	010-TK-0001	1
4.	Rainwater Sump Pump	010-P-0004A/B	2

Miscellaneous Materials Scope			
Item	**Description**	**Supplier**	**Purchaser**
1.	All nuts, bolts, gaskets, special fasteners, backing rings, and other accessories required for installation of components and furnished equipment.	X	
2.	All piping integral to equipment and skids.	X	
3.	All coupling guards, belt guards, and personnel safety items required for furnished equipment.	X	
4.	All connections on furnished equipment for interfacing to Purchaser-furnished piping and instruments.	X	
5.	All valves and instruments required for automatic control and monitoring of the furnished system (or for manual control and monitoring of the system).	X	
6.	All instrument, power, and control wiring and raceway integral to equipment, skids, or packages furnished. Junction boxes shall be furnished with terminal blocks and internal wiring to these terminal blocks for equipment requiring external connection. In general, motors shall be rated 460VAC. Any main auxiliary power feeds to equipment skids will utilize 480VAC as the source of power.	X	
7.	Electrical and control wiring to connect furnished equipment terminal points to the plant electrical and control systems.		X
8.	Motor controls and starters for furnished equipment (Other than motor operated valves).		X
9.	Motor starters for motor operated valves (integral to valve actuators)	X	
10.	Ground pads and lugs for furnished equipment, skids and structures (minimum of two per skid or structure).	X	
11.	Heat tracing and insulation for freeze protection of pipe and devices on furnished equipment.		X
12.	Spare parts.	X	

Miscellaneous Materials Scope			
Item	**Description**	**Supplier**	**Purchaser**
13.	One set of maintenance tools required for dismantling, maintenance, and overhaul of the equipment. The tools shall be shipped in separate, heavily constructed wooden boxes provided with hinged covers and padlock hasps.	X	
14.	The use of all special tools and hardware required for erection of the equipment, exclusive of the maintenance tools furnished. Erection tools shall remain the property of Supplier, and all shipping costs to and from the jobsite shall be at Supplier's expense.	X	
15.	One set of consumable materials required for erection, startup and testing.	X	
16.	Permanently attached identification tags for all equipment and devices	X	
17.	Shop applied coating including but not limited to finish paint on all shop fabricated equipment, ancillary skids, material, structures and ancillary skid systems.	X	
18.	Finish painting/coating	X	
19.	Touchup paint for field		X
20.	Solvents and cleaning materials.		X
21.	Lifting eyes and lugs for offloading and setting equipment.	X	
22.	Permanent foundations/tie-down pads		X
23.	Leveling blocks, soleplates, thrust blocks, matching blocks, and shims.		X
24.	Anchor bolts, soleplates, or other items required to be permanently cast into concrete.		X
25.	All other features as specified in this procurement package.	X	

Miscellaneous Engineering/Services Scope			
Item	**Description**	**Supplier**	**Purchaser**
1.	Design, fabrication, testing, packaging, and delivery of all equipment.	X	
2.	Shop drawing submittals.	X	
3.	Shop testing.	X	
4.	Shop material inspection and testing.	X	
5.	Calibration of all instrumentation furnished.	X	
6.	Field technical advisor service time (2 Weeks on-site, 5-8 hr days).	X	

Miscellaneous Engineering/Services Scope			
Item	Description	Supplier	Purchaser
7.	Training Manuals including detailed training objectives, equipment overview, major component and support system description, controls, principle of operation, and testing materials.		X
8.	Operating personnel for site inspection, startup and testing.		X
9.	Receiving, unloading, storing, and field erection of all equipment.		X

01100.2 Drawings and Technical Attachments

This article lists the drawings and other technical attachments that have been prepared for the work under these specifications.

01100.2.1 Engineer's Attachments

The following listed attachments shall be part of the Purchase Order.

Drawing No. or Other Designation	Rev. No.	Title
401616-0100-P1000	B	Anaerobic Digestion
N/A	B	PGE MPT Microgrid Mass Balance WINTER
N/A	B	PGE MPT Microgrid Mass Balance SUMMER
401616-0000-P0101	C	PG&E Equipment List
401616-0000-G2000	B	Overall Site Layout

01100 - Technical Scope and Performance Requirements

01100.1 Technical Scope of Work

The work under these specifications shall include furnishing the following:

Black & Veatch is assisting with the design and development of a renewable natural gas (RNG) Production and Distribution Facility. The following stream numbers refer to the process streams shown in the attached mass balance. The new biogas conditioning equipment includes all equipment from the raw biogas (stream 12) through the compressed, cleaned RNG (stream 17). All upstream equipment to produce biogas and all downstream equipment to dispense RNG are covered under separate scopes of supply. The project site is located approximately eight miles south of Modesto in the town of Ceres, CA, which is in the San Joaquin Valley (SJV). The site has access via well maintained secondary roads. Major transportation links in the vicinity include California Route 99 to the east and California Route 33 / Interstate 5 to the west.

Site-Specific Design Criteria

Design Barometric Pressure:	14.66 psia [NOTE 1]
Elevation:	73 ft
Design Minimum Ambient Temperature:	20 °F [NOTE 1]
Design Maximum Ambient Temperature (dry bulb):	113.6 °F [NOTE 1]
Design Maximum Ambient Temperature (wet bulb):	79.3 °F [NOTE 1]
NOTES 1. Based on ASHRAE HVAC design data for 724926 weather station.	

Refer to Article 01100.2.1 for attachments detailing the process information. The attachments include the following to identify required process inlet and outlet conditions: process flow diagrams of the systems and a mass balance with the stream conditions of each process flow. The supplier shall provide a complete engineered package that accepts the defined inputs of stream 12 in Article 01100.2.1 and produces the output specification defined below (stream 17).

Design Basis Parameters

Condition	Value
Pressure $_{inlet}$ (psig)	0
Pressure $_{outlet}$ (psig)	3,600
Temperature (ºF)	100
Biogas Inlet Flow (SCFM)	115 – 125
RNG Outlet Flow (SCFM)	75 – 80

The RNG specification is as follows that must be met by the biogas conditioning equipment is as follows:

RNG Specification

Constituent	Units	Value
Methane	Vol %	>95%
Oxygen	Vol %	≤0.1%
Nitrogen	Vol %	<3%
Carbon Dioxide	Vol %	≤1%
Total Sulfur	ppm_v	≤17
Hydrogen Sulfide	ppm_v	≤4
Water Vapor	lb/MMSCF	≤7
Siloxanes	mg/Nm^3	0.1

Major Equipment Scope			
Item	**Description**	**Tag Number(s)**	**Quantity**
1.	Digester Gas Feed Compressor	020-C-0001	1
2.	Digester Gas After Cooler	020-E-0001	1
3.	Digester Gas Flare Blower	020-B-0001	1
4.	Digester Gas Carbon Filter	020-FL-0001	1
5.	H_2S Removal	020-FL-0002	1
6.	Dryer	020-U-0001	1
7.	Membrane Gas Separation	020-FL-0003	1
8.	RNG Gas Compressor	030-C-0001	1
9.	RNG Gas After Cooler	030-E-0001	1
10.	Propane Storage (Flare Fuel Supply)	040-V-0001	1
11.	Flare Burner	040-F-0001	1
12.	Flare (Includes Staged Burn for Thermal Oxidation)	040-F-0002	1
13.	Stack	040-S-0001	1
14.	Flare Fan	040-B-0001	1
15.	Inlet Air Filter	040-FL-0001	1

Miscellaneous Materials Scope			
Item	**Description**	**Supplier**	**Purchaser**
1.	All nuts, bolts, gaskets, special fasteners, backing rings, and other accessories required for installation of components and furnished equipment.	X	
2.	All piping integral to equipment and skids.	X	
3.	All coupling guards, belt guards, and personnel safety items required for furnished equipment.	X	
4.	All connections on furnished equipment for interfacing to Purchaser-furnished piping and instruments.	X	
5.	All valves and instruments required for automatic control and monitoring of the furnished system (or for manual control and monitoring of the system).	X	

Miscellaneous Materials Scope			
Item	**Description**	**Supplier**	**Purchaser**
6.	All instrument, power, and control wiring and raceway integral to equipment, skids, or packages furnished. Junction boxes shall be furnished with terminal blocks and internal wiring to these terminal blocks for equipment requiring external connection. In general, motors shall be rated 460VAC. Any main auxiliary power feeds to equipment skids will utilize 480VAC as the source of power.	X	
7.	Electrical and control wiring to connect furnished equipment terminal points to the plant electrical and control systems.		X
8.	Motor controls and starters for furnished equipment (Other than motor operated valves).		X
9.	Motor starters for motor operated valves (integral to valve actuators)	X	
10.	Ground pads and lugs for furnished equipment, skids and structures (minimum of two per skid or structure).	X	
11.	Heat tracing and insulation for freeze protection of pipe and devices on furnished equipment.		X
12.	Spare parts.	X	
13.	One set of maintenance tools required for dismantling, maintenance, and overhaul of the equipment. The tools shall be shipped in separate, heavily constructed wooden boxes provided with hinged covers and padlock hasps.	X	
14.	The use of all special tools and hardware required for erection of the equipment, exclusive of the maintenance tools furnished. Erection tools shall remain the property of Supplier, and all shipping costs to and from the jobsite shall be at Supplier's expense.	X	
15.	One set of consumable materials required for erection, startup and testing.	X	
16.	Permanently attached identification tags for all equipment and devices	X	
17.	Shop applied coating including but not limited to finish paint on all shop fabricated equipment, ancillary skids, material, structures and ancillary skid systems.	X	
18.	Finish painting/coating	X	
19.	Touchup paint for field		X
20.	Solvents and cleaning materials.		X

Miscellaneous Materials Scope			
Item	**Description**	**Supplier**	**Purchaser**
21.	Lifting eyes and lugs for offloading and setting equipment.	X	
22.	Permanent foundations/tie-down pads		X
23.	Leveling blocks, soleplates, thrust blocks, matching blocks, and shims.		X
24.	Anchor bolts, soleplates, or other items required to be permanently cast into concrete.		X
25.	All other features as specified in this procurement package.	X	

Miscellaneous Engineering/Services Scope			
Item	**Description**	**Supplier**	**Purchaser**
1.	Design, fabrication, testing, packaging, and delivery of all equipment.	X	
2.	Shop drawing submittals.	X	
3.	Shop testing.	X	
4.	Shop material inspection and testing.	X	
5.	Calibration of all instrumentation furnished.	X	
6.	Field technical advisor service time (2 Weeks on-site, 5-8 hr days).	X	
7.	Training Manuals including detailed training objectives, equipment overview, major component and support system description, controls, principle of operation, and testing materials.		X
8.	Operating personnel for site inspection, startup and testing.		X
9.	Receiving, unloading, storing, and field erection of all equipment.		X

01100.2 Drawings and Technical Attachments

This article lists the drawings and other technical attachments that have been prepared for the work under these specifications.

01100.2.1 Engineer's Attachments

The following listed attachments shall be part of the Purchase Order.

Drawing No. or Other Designation	Rev. No.	Title
401616-0200-P1000	B	Digester Gas Treatment
401616-0300-P1000	B	Digester Gas Compression

401616-0400-P1000	B	Flare
N/A	B	PGE MPT Microgrid Mass Balance WINTER
N/A	B	PGE MPT Microgrid Mass Balance SUMMER
401616-0000-P0101	C	PG&E Equipment List
401616-0000-G2000	B	Overall Site Layout

01100 - Technical Scope and Performance Requirements

01100.1 Technical Scope of Work

The work under these specifications shall include furnishing the following:

Black & Veatch is assisting with the design and development of a renewable natural gas (RNG) Production and Distribution Facility. The following stream numbers refer to the process streams shown in the attached mass balance. The new RNG refueling facility will use a high-pressure compressor to increase the pressure to meet user specifications and distribute RNG for local vehicle refueling. All upstream equipment to produce and clean biogas to RNG specifications is covered under separate scopes of supply. The project site is located approximately eight miles south of Modesto in the town of Ceres, CA, which is in the San Joaquin Valley (SJV). The site has access via well maintained secondary roads. Major transportation links in the vicinity include California Route 99 to the east and California Route 33 / Interstate 5 to the west.

Site-Specific Design Criteria

Design Barometric Pressure:	14.66 psia [NOTE 1]
Elevation:	73 ft
Design Minimum Ambient Temperature:	20 °F [NOTE 1]
Design Maximum Ambient Temperature (dry bulb):	113.6 °F [NOTE 1]
Design Maximum Ambient Temperature (wet bulb):	79.3 °F [NOTE 1]
NOTES 1. Based on ASHRAE HVAC design data for 724926 weather station.	

Refer to Article 01100.2.1 for attachments detailing the process information. The attachments include the following to identify required process inlet and outlet conditions: process flow diagrams of the systems, a mass balance with the stream conditions of each process flow. At the outlet of the compressor (steam 17), the stream flows through a shell and tube heat exchanger to be reduced to a temperature of <100 ºF. Other's scope terminates at the point of receipt, downstream of the heat exchanger. The client, Pacific Gas & Electric (PG&E) is responsible for regulating flow to and dispensing equipment for the tube trailers and regulating flow to the RNG refueling dispenser storage vessel. Black & Veatch's scope then resumes at the dispenser storage vessel (stream 19), which operates as a storage vessel to provide compressed RNG to users via RNG dispensers at 3,600 psig. The supplier shall provide a complete engineered package that accepts the defined input stream and produces the output streams defined above. Inlet conditions to the equipment are as follows:

Design Basis Parameters

Condition	Value
Pressure (psig)	3,600
Temperature (ºF)	<100
Flow (SCFM)	75 – 80

Major Equipment Scope			
Item	**Description**	**Tag Number(s)**	**Quantity**
1.	Dispenser Storage Vessel	030-V-0003A/B/C	3
2.	RNG Dispenser	030-PK-0001A/B	2
3.	Dispenser Canopy	030-U-0002	1

Miscellaneous Materials Scope			
Item	**Description**	**Supplier**	**Purchaser**
1.	All nuts, bolts, gaskets, special fasteners, backing rings, and other accessories required for installation of components and furnished equipment.	X	
2.	All piping integral to equipment and skids.	X	
3.	All coupling guards, belt guards, and personnel safety items required for furnished equipment.	X	
4.	All connections on furnished equipment for interfacing to Purchaser-furnished piping and instruments.	X	
5.	All valves and instruments required for automatic control and monitoring of the furnished system (or for manual control and monitoring of the system).	X	
6.	All instrument, power, and control wiring and raceway integral to equipment, skids, or packages furnished. Junction boxes shall be furnished with terminal blocks and internal wiring to these terminal blocks for equipment requiring external connection. In general, motors shall be rated 460VAC. Any main auxiliary power feeds to equipment skids will utilize 480VAC as the source of power.	X	
7.	Electrical and control wiring to connect furnished equipment terminal points to the plant electrical and control systems.		X
8.	480VAC Motor controls and starters for furnished equipment.		X
9.	Ground pads and lugs for furnished equipment, skids and structures (minimum of two per skid or structure).	X	
10.	Heat tracing and insulation for freeze protection of pipe and devices on furnished equipment.	X	
11.	Spare parts.	X	
12.	One set of maintenance tools required for dismantling, maintenance, and overhaul of the equipment. The tools shall be shipped in separate, heavily constructed wooden boxes provided with hinged covers and padlock hasps.	X	
13.	The use of all special tools and hardware required for erection of the equipment, exclusive of the maintenance tools furnished. Erection tools shall remain the property of Supplier, and all shipping costs to and from the jobsite shall be at Supplier's expense.	X	

Miscellaneous Materials Scope			
Item	**Description**	**Supplier**	**Purchaser**
14.	One set of consumable materials required for erection, startup and testing.	X	
15.	Permanently attached identification tags for all equipment and devices	X	
16.	Shop applied coating including but not limited to finish paint on all shop fabricated equipment, ancillary skids, material, structures and ancillary skid systems.	X	
17.	Finish painting/coating	X	
18.	Touchup paint for field		X
19.	Solvents and cleaning materials.		X
20.	Lifting eyes and lugs for offloading and setting equipment.	X	
21.	Permanent foundations/tie-down pads		X
22.	Leveling blocks, soleplates, thrust blocks, matching blocks, and shims.		X
23.	Anchor bolts, soleplates, or other items required to be permanently cast into concrete.		X
24.	All other features as specified in this procurement package.	X	

Miscellaneous Engineering/Services Scope			
Item	**Description**	**Supplier**	**Purchaser**
1.	Design, fabrication, testing, packaging, and delivery of all equipment.	X	
2.	Shop drawing submittals.	X	
3.	Shop testing.	X	
4.	Shop material inspection and testing.	X	
5.	Calibration of all instrumentation furnished.	X	
6.	Field technical advisor service time (2 Weeks on-site, 5-8 hr days).	X	
7.	Training Manuals including detailed training objectives, equipment overview, major component and support system description, controls, principle of operation, and testing materials.		X
8.	Operating personnel for site inspection, startup and testing.		X
9.	Receiving, unloading, storing, and field erection of all equipment.		X

01100.2 Drawings and Technical Attachments

This article lists the drawings and other technical attachments that have been prepared for the work under these specifications.

01100.2.1 Engineer's Attachments

The following listed attachments shall be part of the Purchase Order.

Drawing No. or Other Designation	Rev. No.	Title
401616-0300-P100	B	Digester Gas Compression
N/A	B	PGE MPT Microgrid Mass Balance WINTER
N/A	B	PGE MPT Microgrid Mass Balance SUMMER
401616-0000-P0101	C	PG&E Equipment List
401616-0000-G2000	B	Overall Site Layout

Appendix K. Capital Cost Estimate

PG&E

MPT Gas Microgrid

ESTIMATE SUMMARY

Cost Type	Description	Labor Man Hrs	Wage Rate	Labor Cost	Material Cost	Subcontract Cost	Total Cost
			$70.00				
01	Demolition					$0	$0
02	Site Work			$0	$0	$835,000	$835,000
03	Foundations & Concrete	320		$22,000	$73,000	$80,000	$175,000
04	Buildings			$0	$0	$0	$0
05	Steel	373		$26,000	$44,000	$250,000	$320,000
06	Process & Mechanical Equipment			$0	See Breakout	$300,000	$300,000
06A	Lagoon Digester	976		$68,000	$2,211,000		$2,279,000
06B	Biogas Cleaning	824		$58,000	$1,867,000		$1,925,000
06C	CNG Refueling	369		$26,000	$836,000		$862,000
07	Piping & Piping Specials	1,652		$116,000	$344,000	$0	$460,000
08	Electrical Equipment	Incl. Below		Incl. Below	$390,000	$0	$390,000
09	Electrical Bulks	400		$28,000	$84,000	$0	$112,000
10	Instrument Equipment	Incl. Below		Incl. Below	$0	$0	$0
11	Instrument Bulks	160		$11,000	$34,000	$0	$45,000
12	Insulation					$39,000	$39,000
13	Painting					$23,000	$23,000
	Productivity Adj. for CA	1,775		$124,000			$124,000
	Subtotal	6,848	$70.00	$479,000	$5,883,000	$1,527,000	$7,889,000
81	CM & Startup Staff					$420,000	$420,000
84	S/C Indirects	100%	of Direct Labor Cost			$479,000	$479,000
91	Engineering					$508,000	$508,000
92	Contingency	5%	of Direct and Indirect Costs			$465,000	$465,000
	Project Total	6,849		$479,000	$5,883,000	$3,399,000	$9,761,000

PG&E

MPT Gas Microgrid

ESTIMATE SUMMARY

Cost Type	Description	Labor Man Hrs	Wage Rate	Labor Cost	Material Cost	Subcontract Cost	Total Cost
			$60.00				
01	Demolition			$0	$0	$0	$0
02	Site Work			$0	$0	$835,000	$835,000
03	Foundations & Concrete	200		$12,000	$70,000	$80,000	$162,000
04	Buildings			$0	$0	$0	$0
05	Steel	0		$0	$0	$250,000	$250,000
06	Process & Mechanical Equipment			$0	See Breakout	$150,000	$150,000
06A	Lagoon Digester	1,000		$60,000	$1,650,000	$0	$1,710,000
06B	Biogas Cleaning	500		$30,000	$1,470,000	$0	$1,500,000
06C	CNG Refueling	300		$18,000	$836,000	$0	$854,000
07	Piping & Piping Specials	500		$30,000	$100,000	$0	$130,000
08	Electrical Equipment	Incl. Below		Incl. Below	$390,000	$0	$390,000
09	Electrical Bulks	200		$12,000	$47,000	$0	$59,000
10	Instrument Equipment	0		0	$0	$0	$0
11	Instrument Bulks	0		$0	$0	$0	$0
12	Insulation					$24,000	$24,000
13	Painting					$13,000	$13,000
	Productivity Adj. for CA	500		$30,000			$30,000
	Subtotal	3,200	$60.00	$192,000	$4,563,000	$1,352,000	$6,107,000
81	CM & Startup Staff					$210,000	$210,000
84	S/C Indirects	100%	of Direct Labor Cost			$192,000	$192,000
91	Engineering					$700,000	$700,000
92	Contingency	2%	of Direct and Indirect Costs				$0
	Project Total	3,200		$192,000	$4,563,000	$2,454,000	$7,209,000

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT B

GNA INCENTIVES REPORT

GLADSTEIN, NEANDROSS & ASSOCIATES

CLEAN TRANSPORTATION & ENERGY CONSULTANTS

MEMORANDUM

June 6, 2019

TO: David Lewis – Director, Wholesale Marketing & Business Development, Pacific Gas and Electric

FROM: Cliff Gladstein – President, Gladstein, Neandross & Associates

SUBJECT: Incentives Report for PG&E re: Monterey Park Tract Opportunity

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Pacific Gas and Electric (PG&E) has asked Gladstein, Neandross & Associations (GNA) to provide a report that summarizes the financial resources, grant and other incentive programs that can be harnessed by public and private interests for the development of dairy digester projects and associated conditioning and interconnect infrastructure. These resources will be used to deliver dairy manure-derived renewable natural gas (RNG) to the Monterey Park Tract (MPT) Project. In addition, GNA has been asked to summarize resources for financial assistance that can be harnessed to support the purchase and deployment of natural gas vehicles that could consume surplus renewable gas that is not used by residential consumers.

In performing this project, GNA focused on the following areas:

- California and Federal grant and/or other programs (tax credits, tax deductions, tax exemptions, low interest loans, loan guarantees, etc.) that support the development of dairy digesters and related infrastructure, including infrastructure related to transportation fueling infrastructure and related CNG/RNG vehicle procurement.
- Discussions with developers responsible for the construction and operation of dairy digester projects to gather information useful for determining the most relevant funding and revenue opportunities.
- Other sources of non-energy value revenue that can support the CAPEX and/or OPEX of dairy digesters and related infrastructure (i.e. Low Carbon Fuel Standard (LCFS), Renewable Fuel Standard (RFS), Renewable Energy Credits (RECs), utility procurement requirements, etc.).

In summarizing this information, GNA focused, as applicable and available for each source of funding, providing the following data:

  - Identify remaining amounts available after awards already made,
  - Identify timing of future requests for proposals or known deadlines or sunset dates for programs or funds; and,
  - Identify contact information for active opportunities for funding

In the discussion of each these funding sources, GNA provided, to the extent possible, data on the total level of resources that are allocated to the individual program as well as the total amount of resources that remain unprogrammed at the time of the report.

Digester Infrastructure Programs

The following incentive programs provide funding for capital costs and/or operational expenses related to the construction and installation of digester facilities as well as associated clean up and interconnection infrastructure.

Community-Scale and Commercial-Scale Advanced Biofuels Production Facilities

Program Description: Encourage the production of alternative and renewable transportation fuels that can significantly reduce greenhouse gas (GHG) emissions, displace petroleum fuel demand, and stimulate economic development.

Funding Agency: California Energy Commission

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q4 2019

Total Available Funds: $16,900,000

Maximum Incentive per Project: Commercial-scale projects (greater than 1,000,000 Diesel Gallon Equivalent [DGE]) are eligible for up to $5,000,000. Community-scale projects (100,000 to 1,000,000 DGE) are eligible for up to $3,000,000.

Eligible Costs: Facility pre-engineering and design; engineering plans and specifications; performance tests, material assessments and other technical studies to verify product or equipment operating characteristics, equipment integrity, market applications, and compliance with regulations, standards and/or protocols; building and facility construction, modifications, and/or operations; asset and/or equipment acquisition; feedstock development activities; verification of advanced biofuel attributes and characteristics, and data collection and modeling; enhancement of biofuel production technology; facility process efficiency improvements leading to reductions in GHG emissions; and process improvements to accommodate lower carbon intensity feedstock and fuel production.

Dairy Digester Research and Development Program

Program Description: Supports the implementation of dairy digesters to promote methane GHG emission reductions in the agriculture sector.

Funding Agency: California Department of Food and Agriculture

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q1 2020

Total Available Funds: $35,000,000

Maximum Incentive per Project: Up to 50% of the total project cost with a maximum grant award of $3,000,000 per project.

Eligible Costs: Capital costs associated with the infrastructure and support equipment for dairy digesters. Applicants can submit multiple grant applications; however, each grant application must represent an individual digester project at a unique project site.

Biomethane Interconnector Monetary Incentive Program

Program Description: Pursuant to CPUC Decision 15-06-029 (2015) and subsequently modified by AB 2313 (2016), this program encourages the development of biomethane projects that are interconnected to the utilities' gas pipeline systems. The program will provide 50% of the interconnection costs up to a maximum of $3 million per project and up to $5 million for the pipeline interconnect for a cluster of three (3) or more dairy digesters.

Funding Agency: California Public Utilities Commission

Eligible Appliances: Public or private entities

Program Timeframe: As currently crafted, the monetary incentive is available to eligible Biomethane Interconnectors until December 31, 2021, or until the program has exhausted its $40 million cap. SB 457 (Hueso), currently being considered by the California Legislature, would extend the deadline for the program to December 31, 2026.

Total Available Funds: $40,000,000.

Maximum Incentive per Project: 50% of total interconnection cost to a maximum of $3,000,000 for non-dairy biomethane projects and 50% of total interconnection cost to a maximum of $5,000,000 for dairy cluster digester projects (three or more dairies).

Eligible Costs: All costs associated with the construction and commissioning of the interconnection between the biomethane producer and the utility gas pipeline.

Demonstration-Scale Advanced Biofuels Production Facilities

Program Description: Encourages the production of alternative and renewable transportation fuels that can significantly reduce GHG emissions, displace petroleum fuel demand, and stimulate economic development.

Funding Agency: California Energy Commission

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q4 2019

Total Available Funds: $6,000,000

Maximum Incentive per Project: 75% per project or $3,000,000, whichever is less

Eligible Costs: Facility pre-engineering and design; engineering plans and specifications; performance tests, material assessments and other technical studies to verify product or equipment operating characteristics, equipment integrity, market applications, and compliance with regulations, standards and/or protocols; building and facility construction, modifications, and/or operations; asset and/or equipment acquisition; feedstock development activities;

verification of advanced biofuel attributes and characteristics, and data collection and modeling; enhancement of biofuel production technology; facility process efficiency improvements leading to reductions in GHG emissions; and process improvements to accommodate lower carbon intensity feedstock and fuel production.

FY19 Bioenergy Technologies Office Multi-Topic Funding Opportunity Announcement (AOI 9: Rethinking Anaerobic Digestion)

Program Description: Demonstration of wet waste to biogas digestion at a less than 5 dry tons/day scale. Demonstrate processes with reduced disposal costs or diversion requirements.

Funding Agency: U.S. Department of Energy

Eligible Applicants: Public and commercial entities

Program Timeframe: Concept Papers due June 3, 2019. Similar funding opportunities are expected to open Q3 2020.

Total Available Funds: $5,000,000

Maximum Incentive per Project: $3,000,000

Eligible Costs: Project equipment and labor with at least 20% required cost share.

Modified Accelerated Cost-Recovery System (MACRS)

Program Description: Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions.

Funding Agency: U.S. Internal Revenue Service

Eligible Applicants: Businesses

Program Timeframe: Involvement in the program filed as part of annual tax filings. Benefit generated over a 3- to 5-year depreciation.

Total Available Funds: Not applicable

Maximum Incentive per Project: Not applicable

Eligible Costs: Capital cost depreciation. Bonus Depreciation has been sporadically available at different levels during different years. Most recently, The Tax Cuts and Jobs Act of 2017 increased bonus depreciation to 100% for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023

Rural Energy for America Program (REAP)

Program Description: Provide financial assistance to agricultural producers and rural small businesses in America to purchase, install, and construct renewable energy systems, make energy efficiency improvements to non-residential buildings and facilities, use renewable technologies that reduce energy consumption, and participate in energy audits and renewable energy development assistance.

Funding Agency: U.S. Department of Agriculture

Eligible Entities: Agricultural producers and rural small businesses

Program Timeframe: April 1 of each year for grants; Continuous application cycle for guaranteed loans

Total Available Funds: $600,000,000 for the current fiscal year

Maximum Incentive per Project: Grants of 25% of project costs up to $500,000 and up to $25 million loan guarantee

Eligible Costs: System, assessment, permitting, licensing fees, and business plan expenses with at least 25% required cost share.

Alternative Fuel Vehicle and Refueling Infrastructure Programs

Critical to the financial success of dairy digester projects is the ability to sell surplus gas to the transportation sector, where the gas has the highest monetary value. Thus, programs that increase demand for RNG in transportation indirectly support the development of dairy digesters. The following incentive programs provide funding for the purchase and deployment of low and near zero emission vehicles that could be end users of dairy RNG.

Advanced Freight and Fleet Technologies Program

Program Description: Expected to support zero emission vehicle and infrastructure research, development, and demonstration projects to accelerate clean transportation adoption at larger scales. Based on recent intelligence gathered from the Energy Commission, GNA expects that the program will fund electric and hydrogen recharging/refueling stations and connected vehicle technologies. Thus, this opportunity would be tangential to the Monterey Park Tract effort in that RNG could be used to generate electricity for a EV charging station or to HFC for a hydrogen fueling station.

Funding Agency: California Energy Commission

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q3 2019

Total Available Funds: $17,500,000

Maximum Incentive per Project: Under development, but likely to be $3,000,000 to $5,000,000 per project

Eligible Costs: Under development; likely to include charging infrastructure deployment

California VW Program for Combustion Freight and Marine

Program Description: Maximize NOx reductions by funding the most cost-effective, lowest emission Class 7 and 8 vehicles equipped with ultra-low NOx (0.02 g/bhp-hr) engines.

Funding Agency: California Air Resources Board (CARB) and administered by the South Coast Air Quality Management District (SCAQMD); though the program is administered by SCAQMD, fleets within the SJVAPCD as well as the rest of the state will be eligible to apply.

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q3 2019

Total Available Funds: $30,000,000

Maximum Incentive per Project: No maximum established

Eligible Costs: Vehicle replacement and/or repower costs are eligible. Applicants may secure $35,000 to $85,000 per ultra-low NOx vehicle, depending on size, ownership, and project type.

Clean School Bus Rebate Program

Program Description: Replace school buses powered by model year 2006 or older engines with new conventional and alternative fuel vehicles to reduce diesel emissions.

Funding Agency: U.S. Environmental Protection Agency

Eligible Applicants: Public and private school bus operators

Program Timeframe: Expected to open Q4 2019

Total Available Funds: Expected to be $9,000,000, based on the last solicitation's funding levels

Maximum Incentive per Project: $400,000 for fleets with more than 100 buses. $200,000 for fleets with less than 100 buses

Eligible Costs: $15,000 per Class 3-5 bus and $20,000 per Class 6-8 bus

Drive Clean! Rebate Program

Program Description: Provide rebates to residents and businesses for the purchase of new, clean-air vehicles.

Funding Agency: San Joaquin Valley Air Pollution Control District (SJVAPCD)

Eligible Applicants: Private and public entities and individuals

Program Timeframe: Open now on a first-come, first-served basis

Total Available Funds: No maximum established

Maximum Incentive per Project: 25% of total vehicle cost up to $3,000. There is no maximum per project level established.

Eligible Costs: Capital costs of purchasing a new vehicle

Goods Movement Emission Reduction Projects (Proposition 1B Program)

Program Description: Replace heavy duty diesel trucks with new alternative fuel equipment, install charging/fueling infrastructure, and/or install truck-stop electrification.

Funding Agency: SJVAPCD

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q3 2019

Total Available Funds: Under development

Maximum Incentive per Project: Up to $100,000 per heavy-duty natural gas vehicle. There is no maximum per project level established.

Eligible Costs: Capital costs of purchasing a new vehicle and/or the equipment and installation costs for new charging/fueling infrastructure

Hybrid and Zero Emission Truck and Bus Voucher Incentive Project (HVIP) – Low NOx Incentives

Program Description: Encourage and accelerate the deployment of vehicles using engines that meet the optional low NOx standards in California and that use renewable fuels.

Funding Agency: CARB

Eligible Applicants: Private and public entities

Program Timeframe: Open now on a first-come, first-served basis

*Total Available Funds: $*54,294,304 as of May 9, 2019

Maximum Incentive per Project: Up to $45,000 per natural gas vehicle. Fleets are no longer limited to a set number of incentives (cap used to be set at 200 vehicles per applicant).

Eligible Costs: Capital costs of purchasing/leasing a new vehicle

National Clean Diesel Funding Assistance Program

Program Description: Reduce diesel emissions from fleets in poor air quality areas.

Funding Agency: U.S. Environmental Protection Agency

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q3 2019

Total Available Funds: $40,000,000 expected

Maximum Incentive per Project: $1,000,000 to $4,000,000, depending on the region of application.

Eligible Costs: Up to 45% of vehicle replacement costs. Up to 35% of the cost of a new drayage truck.

New CNG Infrastructure Program

Program Description: Reduce emissions through construction of new CNG fueling stations.

Funding Agency: SJVAPCD

Eligible Applicants: Private and public entities

Program Timeframe: Expected to open Q3 2019

Total Available Funds: Under development

Maximum Incentive per Project: Under development

Eligible Costs: Capital costs associated with purchase and installation of refueling equipment

Public Benefit Grant Program – New Alternative Fuel Vehicle Purchase

Program Description: Funds the purchase of new alternative fuel vehicles for public agencies to promote clean air alternative-fuel technologies.

Funding Agency: SJVAPCD

Eligible Applicants: Public Entity

Program Timeframe: Open now on a first-come, first-served basis

Total Available Funds: $8,000,000

Maximum Incentive per Project: $100,000

Eligible Costs: Up to $20,000 per vehicle

Targeted Air Shed Grant Program

Program Description: Support emission reduction planning and projects in the nation's top five non-attainment areas for levels of ozone and PM2.5 ambient air concentrations.

Funding Agency: U.S. Environmental Protection Agency

Eligible Applicants: Governments; Air pollution control agencies

Program Timeframe: Expected to open Q4 2019

Total Available Funds: $40,000,000

Maximum Incentive per Project: $5,000,000. However, the maximum amount that may be requested per application is $3,000,000. Applicants may submit more than one application if they are for different projects and are submitted separately.

Eligible Costs: Capital costs associated with the purchase/lease of new vehicles and/or refueling infrastructure.

Truck Replacement Program

Program Description: Replace older diesel medium- and heavy-duty on road trucks with cleaner alternative fuel vehicles.

Funding Agency: SJVAPCD

Eligible Applicants: Private and public entities

Program Timeframe: Open now on first-come, first-served basis

Total Available Funds: No maximum established

Maximum Incentive per Project: Natural Gas Truck: Up to $100,000 per vehicle. There is no project maximum.

Eligible Costs: Costs of purchasing/leasing a new vehicle

Non-Energy Value Revenue Incentive Programs

The following monetary incentives increase the value of the dairy RNG if that gas is used as a fuel in a motor vehicle (LCFS, RFS) or the RNG is used to produce renewable electricity. The revenue for these non-energy revenue streams significantly improves the economics of diary digester development, and is a substantial incentive for expansion of this industry.

Low Carbon Fuel Standard

Program Description: A regulatory standard for the carbon content of motor vehicle fuels for sale in California. All fuel providers must either reduce the carbon content of the motor vehicle fuels that they sell in CA or purchase credits from those who either exceeded their requirement or produce alternative fuels with low carbon content. The LCFS to reduce the carbon intensity (CI) of transportation fuels by 7.5% by 2020 and by 20% by 2030.

Administering Agency: CARB

Eligible Participants: The carbon market will include Credit Generators and Credit Purchasers. Credit Generators include producers and importers of low carbon fuels (i.e. dairy digesters), zero-emission vehicle infrastructure owners, and operators of projects that have been verified for their emission-reducing actions. Credit Purchasers include any regulated party (e.g., refiner or motor vehicle fuel retailer) that needs to meet emission reduction goals.

Program Timeframe: The program operates on an ongoing basis. Eligible participants submit energy consumption reports within 45 calendar days of the end of each quarter. CARB verifies the reports and issues credits within 90 days of the end of each quarter.

Total Available Funds: There is no maximum for the availability of funds. The market for LCFS credits has been very robust since the inception of the program, and credit value is dictated by the supply and demand of credits. In 2017 there were 35.8 million credits generated at a 2017-average credit price of $89.14/credit (total market value of $3.191 billion). In 2018, there were 47.1 million credits generated at a 2018 average credit price of $160/credit (total market value of $5.756 billion).

Maximum Incentive per Project: There is no defined maximum. Credits are stored or traded at a dollar amount established by the market, based on data reported to CARB. The value of a credit in California as of April 2019 was $180/MT CO2e.

Eligible Costs: Credits are based off of the reduction of a metric ton of carbon emissions.

Renewable Fuel Standard

Program Description: A national policy created under the Energy Policy ACT of 2005 and was expanded and extended by the Energy Independence and Security Act of 2007 that sets a requirement for the amount of petroleum-based transportation fuels that must be replaced by renewable alternatives.

Administering Agency: EPA

Eligible Participants: Refiners and importers of gasoline and diesel sold in the U.S. as motor vehicle fuel must meet volumetric targets for renewable fuel content. These are also known as Obligated Parties, and they must purchase and blend renewable fuels in to their petroleum-based products made available for sale in the U.S. or buy credits from parties that produce renewable transportation fuels, such as dairy RNG. Renewable fuel exporters and producers generate renewable fuel credits, which are called Renewable Identification Numbers (RIN), and are also known as RIN Generators.

Program Timeframe: The program operates on an ongoing basis. RIN Generators enter into trade agreement with Obligated Parties. Each trading partners enters the EPA moderated transaction system (EMTS) to manage transactions. Obligated Parties typically retire RINs by March 31 of each year, but RINs that are not used may carry over into the following compliance year.

Total Available Funds: There is little in the way of reliable data regarding the annual value of the RIN market. RIN prices fluctuate daily, dependent on supply and demand, as well as market perceptions of the future of the RFS program. For 2019, the volume standard set forth in the Energy Independence and Security Act or 2007 (EISA) for all renewable fuels is 28 billion gallons.

Maximum Incentive per Project: There is no set maximum. RINs are only generated from qualifying feedstock and fuel pathways. As of May 2019, the values of D3 and D5 RINs are:

- D3 (biogas from landfills, wastewater, dairy digesters, and biomass): $1.450 per gallon
- D5 (biogas from waste digesters): $0.315 per gallon

Eligible Costs: Renewable identification numbers (RINs) are the currency of the Renewable Fuel Standard Programs (1 RIN = 1 gallon of renewable fuel = 77,000 BTU).

Renewable Energy Credits/Certificates

Program Description: Most U.S. states have requirements that a certain percentage of the electricity that is distributed by electric utilities must come from renewable sources. When a utility does not procure sufficient renewable electricity to meet their requirements, they have the option of purchasing Renewable Energy Credits (also known as Renewable Energy Certificates), or RECs, from a third party. A REC represents one megawatt hour (MWh) of electricity from a renewable source, which includes RNG-fueled generators in California and other states. The REC can be unbundled from the energy value and sold separately. RECs generated in California, for instance, can be sold in another state to a utility that needs the credit to meet their renewable portfolio obligation. Some states will require that the any RECs used for compliance purposes must be generated within the same North American Electric Reliability Corporation (NERC) region as the buyer.

In addition to states that have mandated a Renewable Portfolio Standard (RPS), where utilities must comply with the requirement to procure a certain percentage of renewable power, RECs can be purchased by parties that are voluntarily choosing to purchase renewable power. An example could be an environmentally conscious business or municipality whose local utility is not required to reduce their environmental footprint. Typically, the prices for “compliance” RECs will be significantly higher than for “voluntary” RECs.

Administering Agency: REC compliance will typically be administered by each state’s public agency responsible for governing electric utilities. Most states will conduct periodic audits of RECs using an accredited certification body, such as the Center for Resource Solutions.

Eligible Participants: On the production side, RECs can be created by any qualifying generator of renewable energy, which includes wind, solar, low-impact hydropower and certain types of biomass, of which dairy gas would likely qualify. On the consumption side, any utility with a RPS compliance requirement can participate, as well as any environmentally conscious party that seeks to purchase and retire the REC.

Program Timeframe: The program operates on an ongoing basis.

Total Available Funds: There is no cap on the total market value of RECs. REC prices vary widely from state to state and are heavily impacted if the buyer is a compliance or voluntary participant.

Maximum Incentive per Project: There is no consistent requirement from state to state that dictates the total portion of a utility’s RPS requirement that may be met through the purchase of RECs.

Eligible Costs: There are no known restrictions on what REC revenue can be used for.

Retail Prices of Renewable Natural Gas

As of this report, there is no additional value for RNG, whether from a dairy digester, a landfill or a wastewater treatment plant, as a fossil gas substitute unless a) the RNG is used as a vehicle fuel or b) the RNG is used to generate renewable electricity. No state, including California, has a renewable gas portfolio standard (the natural gas equivalent of an RPS). Thus, when RNG is used for residential, commercial or industrial applications as a substitute for fossil gas, the seller will only be able to charge the customer the same rate that they charge for fossil gas.

Once, however, the dairy RNG is used to fuel a motor vehicle or to generate renewable electricity, the price of the gas is bolstered by the value of its renewable and/or low carbon attributes. As discussed above, when used as a transportation fuel, particularly in California where the low-carbon attribute of the dairy RNG can be maximized, dairy RNG realizes its peak value. At current D Code 3 and LCFS credit prices, just the renewable and low carbon attributes of the fuel are worth $94/MMBTU when it is used to fuel a motor vehicle.

When the RNG is used to generate renewable electricity, there may be some surplus value to the power if the REC that is generated can be sold to a utility with an RPS requirement. This value, however, is considerably less than that which can be generated from the use of the fuel in transportation. REC prices vary, but generally have been falling in recent years. In California, where most utilities have exceeded their RPS requirements, the price paid for RECs is low compared to other states where meeting the RPS requirement may face more challenges. In addition, as more states develop and implement requirements for solar generated electricity, the prices paid for biomass-generated RECs may be negatively impacted as the solar-RECs (SRECs) have more value in the marketplace.

It should be noted that, although California does have the Bioenergy Market Adjusting Tariff (BioMAT), MPT would not qualify for participation since they are situated in Turlock Irrigation District (TID) electric service territory, not in a California investor owned utility electric service territory.

Conclusion

There are a number of possible third-party funding sources that can be tapped to reduce the CAPEX and/or OPEX of dairy digesters. There will be substantial difference in these incentives depending on whether the gas that is generated by the digester is used for residential gas consumption, power generation, or as a vehicle fuel. Although there are a number of programs that will support the construction of the digester and associated clean up and interconnection infrastructure, additional grants can be obtained on top of these to support the purchase and deployment of motor vehicle end users for the dairy RNG.

When non-energy value attributes are assessed, it dramatically alters the revenue generating capability of the dairy digester project. As of this writing, by far the greatest value for dairy digester gas in California is as a vehicle fuel. However, no funding program requires all the gas that is produced from dairy effluent go to one source, so clearly a strategy that can be pursued is to size the system so that it can both provide for all of the needs of the Monterey Park Tract, but also produce surplus gas that can be sold to a transportation end user. This suggests that, particularly for ratepayers, and dual strategy should be employed to maximize the rate of return.

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company
Alcantar & Kahl LLP

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
P.C. CalCom Solar
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
County of Tehama - Department of Public Works
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

Downey & Brand
East Bay Community Energy
Ellison Schneider & Harris LLP
Energy Management Service
Engineers and Scientists of California
Evaluation + Strategy for Social Innovation
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Charge Networks
Green Power Institute
Hanna & Morton
ICF
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc. Linde
Los Angeles County Integrated Waste Management Task Force
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions

SCE
SDG&E and SoCalGas

SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Utilities
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists

Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy

SoCalGas Comments in Response to the IEPR Joint Agency Workshop on Energy Efficiency and Building Decarbonization & *2019 California Energy Efficiency Action Plan Draft Staff Report*, Docket #19-IEPR-06

Attachment D

White Paper:
Atmospheric Methane, Seasonal Variations, and Space Heating

Executive Summary

A published paper[1] *Atmospheric methane emissions correlate with natural gas consumption from residential and commercial sectors in Los Angeles* (JPL) asserts that winter increases in methane emissions are due to emissions stemming from natural gas consumption during that period of the year in the Los Angeles (LA) metropolitan area. In particular, the JPL paper infers a large impact from natural gas space heating (the largest incremental winter seasonal use of natural gas).

A recently published paper by Merrin and Francisco (M&F) indicates this assertion (i.e., post-combustion methane emissions) in the JPL paper is unlikely to be a primary factor.[2] Our analysis indicates natural gas space heating has up to 0.14 Gg/month of methane emissions in the LA Basin. The JPL paper infers an additional seasonal winter methane emission estimate of 20 Gg/month. This is over 140 times greater than our estimates of post-combustion methane emissions from natural gas space heating equipment. **It is improbable that operation of natural gas space heating is a primary or even secondary contributor to this level of methane emissions.**

The JPL paper also does not include an important mechanism that is a key contributor to seasonal changes in atmospheric methane concentrations – a central element of the investigation. The process of methane oxidation is known to be driven by hydroxyl radical (OH) – which is also a key actor in atmospheric ozone chemistry. **This leads to a process of a summer drop in atmospheric methane concentration on a global basis and is seen independent of methane emissions sources; even locations far from natural gas production and consumption show a summer decline and winter increase in atmospheric methane concentration.** The JPL paper does not include a complete exploration of the possible causation of the seasonal cycles in atmospheric methane concentration; this phenomenon may be enhanced in the LA Basin due to the presence of pollutants such as NO_x and ozone. Further investigation is warranted on this topic.

There is widespread agreement on the need to reduce the level of atmospheric methane and the release of methane from various sources, including natural gas production, delivery, and use. There is also a need to conduct research to improve our understanding of methane emissions and sinks – globally, nationally, and – like the JPL study – regionally. However, there are issues with the JPL study – most notably the likely erroneous conclusion that natural gas space heating is a key contributor to atmospheric methane emissions.

Further research is warranted to improve our understanding of year-round methane emissions and sinks – enabling a better understanding of key factors that can contribute to mitigating methane emissions.

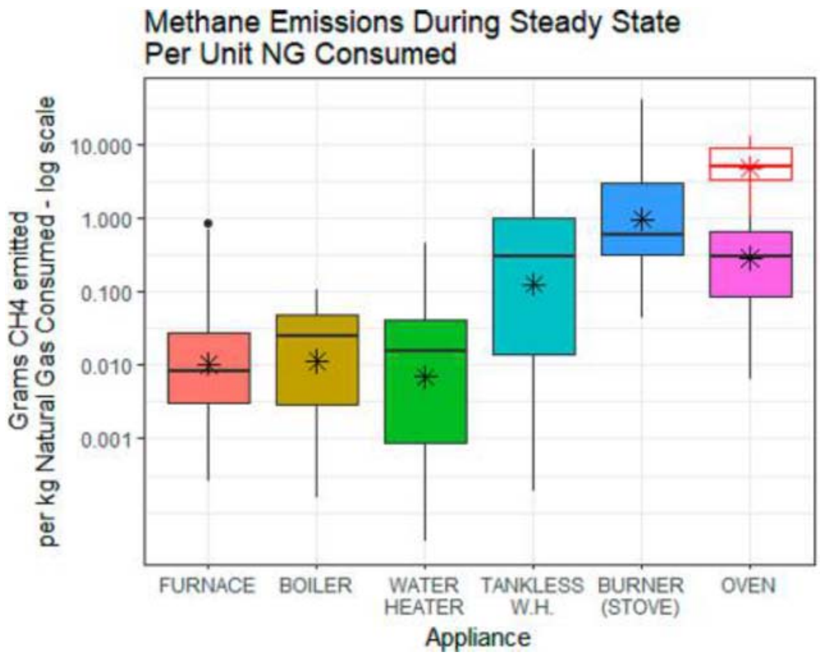
Discussion on Methane Emissions from Natural Gas Space Heating

The JPL paper attempts to make a top-down case for a better understanding of the contribution of methane emissions (bottom-up) sources. In particular, they make an inference that seasonal winter uses of natural gas – which is principally natural gas used for space heating – could be a contributor to seasonal changes in methane.

[1] https://agupubs.onlinelibrary.wiley.com/doi/abs/10.1029/2019GL083400

[2] Merrin, Z. and Francisco, P.W., "Unburned Methane Emissions from Residential Natural Gas Appliances," Env. Sci & Tech., March 25, 2019.

The JPL paper asserts there is a winter-based seasonal component of methane emissions on the order of 20 Gg/month in the LA Basin. They imply this is mainly from winter season natural gas use – that is, space heating. To test this assertion, we use the results of a recently published paper on methane emissions from natural gas equipment by Merrin and Francisco (M&F). For furnaces, M&F find the steady-state emission rate is about 0.008 g of methane/kg of natural gas consumed – **this was the lowest emission rate of the different types of natural gas equipment tested** (see below).



From this testing, most methane emissions stem from equipment start-up and shut down. In fact, at steady-state operation M&F find instances where furnace methane emission levels are lower than background ambient methane concentration (i.e., furnaces in some instances consume ambient methane during steady-state operation). Even factoring in on/off cycles, this study finds very low methane emissions from gas furnaces.

Based on estimates from the JPL paper and other GTI analysis, there is an incremental seasonal natural gas use of about 500 Gg/month in the LA Basin during the winter – mainly for space heating. Using the natural gas furnace methane emission data from the M&F paper (and including different on/off cycle time assumptions), we find a range for furnace methane emissions values of 0.11 - 0.28 g/kg natural gas consumed (the upper value uses an unlikely 5-minute cycle time). Using the upper end value and applying that to 500 Gg/month results in a space heating-related monthly emission value of 0.14 Gg/month. The JPL paper asserts an incremental winter-based methane emissions from natural gas of 20 Gg/month; this emission rate is over 140 times greater than the composite furnace emission rate. **It is improbable that seasonal natural gas combustion for winter space heating is a primary (or secondary) contributor to seasonal changes in atmospheric methane concentration.**

Atmospheric Methane Oxidation and Seasonal Changes in Methane

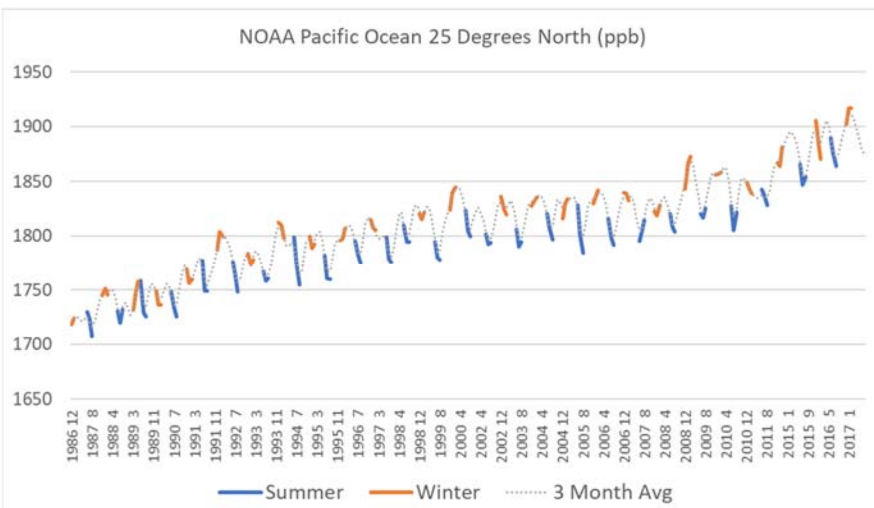
The JPL paper does not discuss the possible contribution of an important mechanism that contributes to seasonal changes in atmospheric methane concentrations. Other similar publications (Townsend-Small) discussing methane emissions in LA have touched on this important factor.[3] The following are two quotes from the Townsend-Small paper:

> "Methane is also an important component in the overall oxidative capacity of the troposphere"

> "This indicates consumption of CH_4 by interaction with OH and other radicals in the urban atmosphere at our study site, which is high in concentration in the summer."

The process of methane oxidation is driven by the hydroxyl radical (OH) – also a key actor in atmospheric ozone chemistry. The role of OH in atmospheric chemistry is complex[4], but there appears to be a link to higher rates of OH formation stemming from more solar ultraviolet (UV) radiation – which is greater during the summer. **This process of a summer drop in atmospheric methane concentration occurs on a global basis and is seen independent of methane emissions sources; even locations far from natural gas production and consumption show a summer decline and winter increase in atmospheric methane concentration.** The JPL paper does not include a complete exploration of the possible causation of the seasonal cycles in atmospheric methane concentration – a phenomenon that may be enhanced within the LA Basin due to the presence of pollutants such as NO_x and ozone.

NOAA has a large database of worldwide atmospheric methane concentration data. Below are NOAA data from the Pacific Ocean at 25° north. This shows summer and winter seasons over an extended number of years.



These multi-year data – located far from natural gas production or consumption sources – show clear seasonal changes in atmospheric methane concentration. Concentration rates are consistently lower and steadily decline in the summer and rebound or rise in the winter in all instances.

The following figure shows multi-year seasonal changes in monthly average methane concentrations at the Mt. Wilson Observatory in California – a primary location discussed in the JPL paper. A cyclical pattern is seen with maximum values in the winter and minimum values in the summer. There is a lack of information to fully describe the behavior of methane and OH at lower elevations in the LA Basin – that is, locations below the planetary boundary layer discussed in the JPL paper. This leads to uncertainty about the dynamic behavior of methane emissions and sinks in the LA Basin throughout the year.

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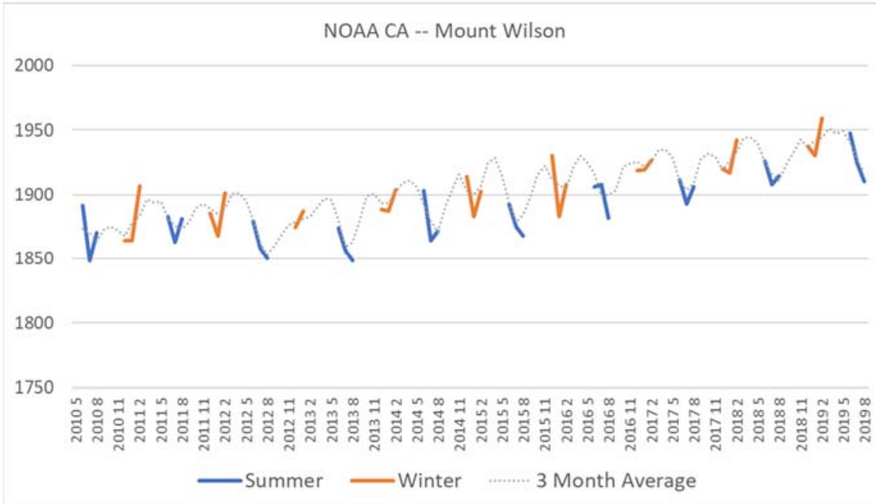
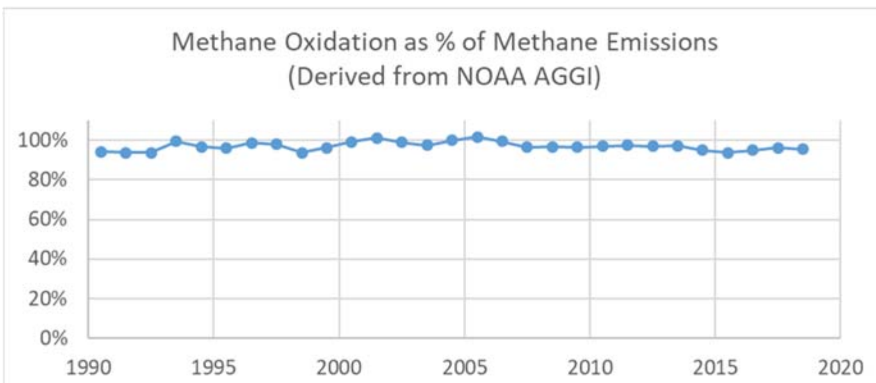
[3] https://www.researchgate.net/publication/231175207_Isotopic_measurements_of_atmospheric_methane_in_Los_Angeles_California_USA_Influence_of_fugitive_fossil_fuel_emissions

[4] https://pubs.acs.org/doi/10.1021/cr500310b#



Methane oxidation is a significant parameter. On an annual basis, the annual amount of methane oxidation is remarkably similar to the amount of methane emissions. Since 1990, methane oxidation has averaged about 97% of methane emissions (GTI calculations from NOAA Annual Greenhouse Gas Index data; assumes a 10-year atmospheric life for methane).



Methane oxidation is the largest single parameter that affects well-mixed atmospheric methane concentrations and highly influential in seasonal changes in methane concentration. The phrase "methane oxidation" never appears in the JPL paper and its influence on monthly or seasonal changes in atmospheric methane concentration is not explicitly discussed (in contrast to the Townsend-Small LA methane emission paper that discusses this topic). The atmospheric conditions over LA in the summer may create conditions that cause a larger fluctuation in atmospheric methane concentrations between summer and winter than what would be encountered naturally. The JPL paper does not explicitly discuss how this phenomenon factors into their analysis.

Methane Sources, Sinks, and Measurement Challenges

There are several salient points to consider with respect to quantitatively assessing methane emission sources, sinks, and measurement: (1) methane emissions are generally small in the context of the total inventory of methane in the atmosphere, (2) **net methane emissions are substantially smaller** (when factoring in continuing reductions from methane oxidation), and (3) large-scale mixing of methane is an ongoing process in the atmosphere, driven by ever-changing winds and gaseous molecular diffusion.

The JPL paper includes atmospheric measurements as well as analyses based on estimates from emission inventory data (which have their own uncertainty). The translation from primary measurements (e.g., ppb of methane) to emissions has further uncertainties. These uncertainties are further compounded by the lack of explicit discussion regarding variable seasonal methane oxidation in the LA Basin (which is unique to other regions of the US) and the challenges with accounting for mixing and diffusion effects.

The JPL paper does not include primary measurements of methane ppb concentrations in the LA Basin (other than the Mt. Wilson background data). Instead, data are shown as a ratio of excess methane to carbon dioxide (CO_2). This analytical approach of coupling methane and CO_2 is curious in that it adds an additional factor (CO_2) that has its own seasonal variability and ties to other fuel sources and factors (e.g., vehicles, plant photosynthetic activity).[5] Further, the vast majority of methane emissions are not from post-combustion emissions (tied to CO_2 emissions), but from pre-combustion emissions from landfills, wastewater treatment facilities, natural gas delivery systems, agricultural operations such as dairy farms, etc. In our estimation, the paper would be better served by focusing specifically on methane measurements as opposed to a convoluted metric (i.e., ratio of excess methane to excess CO_2).

Conclusions

The assertion in the JPL paper that seasonal winter natural gas use (which is predominantly for space heating) is a principal contributor to seasonal changes in atmospheric methane concentration is improbable, based on equipment-level measurements. Post-combustion methane emissions from natural gas furnaces and other similar equipment are much smaller than what JPL infers.

The JPL paper appears incomplete in terms of addressing all possible causes of seasonal changes in atmospheric methane concentrations. An alternative cause for the enhanced seasonal methane changes in the atmosphere may be related to the higher methane oxidation rates that occur during the summer when the combined effects of longer daylight hours (i.e., greater UV radiation) and higher OH formation rates. The unique atmospheric chemistry in the LA Basin – as evidenced by very high ozone concentrations – is an indicator this may be a key parameter for consideration.

It is important to continue to make impactful strides in reducing the methane emission sources – including natural gas production, delivery, and use – and to lower atmospheric methane concentrations. However, the basis and conclusions of the JPL report are not comprehensive and appear to lead to erroneous conclusions. They do not incorporate a potentially large chemical mechanism influencing an enhanced summer time decrease and winter rebound in methane levels – a process which can be seen to occur in remote regions far from natural gas production and consumption. Independent test data from natural gas space heating equipment provides no evidence for methane emission levels approaching those cited in the JPL paper.

Further studies are needed to more fully understand seasonal atmospheric methane concentration changes and refine estimates of methane emission sources and quantities. This is a challenging field of scientific study. Further refinements in measurement technology and methodology are needed to fully account for methane emissions, sinks, and the effects of atmospheric mixing and diffusion.

For More Information

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[5] https://scripps.ucsd.edu/programs/keelingcurve/2013/05/07/why-are-seasonal-co2-fluctuations-strongest-in-northern-latitudes/