Littleton/Englewood Wastewater Treatment Plant

BIOGAS USE APPLICATIONS REPORT

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Abbreviations

AACE	American Association of Cost Engineering
BTU	British thermal unit
Carollo	Carollo Engineers, Inc.
CDOT	Colorado Department of Transportation
CEO	Colorado Energy Office
cf	cubic feet
cfd	cubic feet per day
cfm	cubic feet per minute
cfs	cubic feet per second
CH_4	methane
CMAR	Construction Management at Risk
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalence
DAFT	dissolved air flotation thickener
DGE	diesel gallon equivalents
EPA	Environmental Protection Agency'
F	Fahrenheit
GGE	gasoline gallon equivalents
GHG	greenhouse gas
GWP	Global Warming Potential
H_2S	hydrogen sulfide
HFC	hydrofluorocarbons
HHV	higher heating value
L/EWWTP	Littleton/Englewood Wastewater Treatment Plant
MG	million gallons
mgd	million gallons per day
N_2O	nitrous oxide
NaOH	sodium hydroxide
O&M	operation and maintenance
PFC	perfluorocarbons

ppd	pounds per day
ppm	parts per million
psi	pounds per square inch
RAQC	Regional Air Quality Council
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	renewable natural gas
RTD	Regional Transportation District
RTU	remote terminal unit
scf	standard cubic feet
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
UPS	United Parcel Service
VOC	volatile organic compound
WM	Waste Management

BIOGAS USE APPLICATIONS REPORT

1.1 Introduction

The Littleton/Englewood Wastewater Treatment Plant (L/EWWTP) serves the south metro Denver area and receives sanitary sewer from the Cities of Littleton and Englewood, as well as from 19 other connector districts. The facility was commissioned in 1977 and is currently rated for 50 million gallons per day (mgd), with an approximate average daily flow of 24 mgd.

Biogas produced during the anaerobic digestion process is currently used for digester heating, with the remainder (approximately 40 percent of the gas produced, depending on the season) flared in a waste gas burner. The L/EWWTP initiated the Biogas Use Applications Project as part of the plant's Energy Improvement Program to explore opportunities to handle biogas in an environmentally responsible manner by limiting biogas combustion byproducts being released to the atmosphere, and to create a revenue stream for the L/EWWTP.

This report provides the L/EWWTP with a comprehensive evaluation of various scenarios as a means to beneficially use the L/EWWTP's biogas, including:

- Base Case: Untreated biogas is burned in the existing boiler to maintain anaerobic digester operating temperature (98 degrees Fahrenheit [F]) and the excess gas flared.
- Conversion of biogas to compressed natural gas (CNG) for vehicle fueling.
- Conversion of biogas to CNG for pipeline injection and subsequent distribution for transportation applications by a 3rd party.

1.2 Project Background

This project is part of the City of Englewood's Energy Action Plan, the goal of which is "to reduce total energy use 1 percent annually through 2030, which would compound to reducing total energy use by 12 percent over the 2015 baseline by that time." The L/EWWTP is listed in one of the three areas that Englewood will focus on, "Municipal/Institutional." The entire focus area accounts for 8 percent of the electricity and 1 percent of the natural gas, or 3 to 4 percent of the total community energy use. The L/EWWTP accounts for 76 percent of the area's energy use, and can therefore have a significant impact on Englewood's Energy Action Plan.

The project goals include:

- Develop renewable energy.
- Convert biogas into a revenue source.
- Highlight the L/EWWTP as a community resource.
- Evaluate partnering with neighboring industries.
- Determine technical feasibility and economic viability of beneficially reusing biogas.

1.2.1 L/EWWTP Process

The L/EWWTP consists of a headworks, primary treatment, secondary treatment consisting of trickling filters/solids contact system, followed by nitrification trickling filters, denitrification basins, and chlorine disinfection prior to discharge to the South Platte River. Solids treatment includes co-thickening of primary and secondary solids in dissolved air flotation thickeners (DAFT), anaerobic digestion, and centrifuge dewatering.

1.2.2 Existing Digestion System

The L/EWWTP currently produces roughly 40,000 pounds per day (ppd) of primary and secondary volatile solids, with a buildout production of almost 80,000 ppd (L/EWWTP Master Plan, October 2013). Primary sludge, scum, and secondary sludge are thickened together in the DAFT process and the thickened sludge is pumped to the digesters. The digestion process consists of five anaerobic digesters that are 80 feet in diameter and designed for 29 feet of sidewall depth, for a volume of just over one million gallons (MG) per digester. Digesters 1, 3, 4, and 5 are considered primary digesters and are mixed and heated. Digester 2 is equipped with two mixing pumps and a transfer pump.

Under normal operation, only two digesters are in service at a time, and Digester 2 serves as an active storage digester, which receives and stores the digested sludge prior to dewatering. An aerial view of the digestion system is shown in Figure 1.

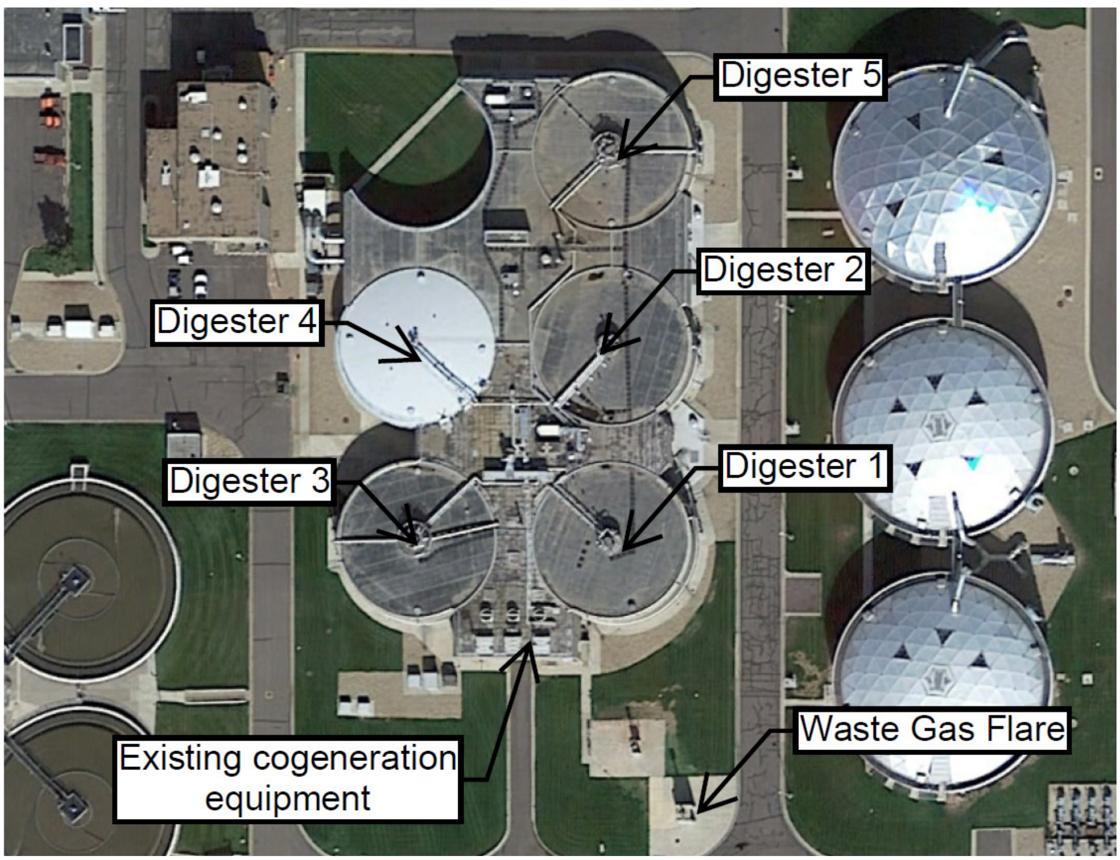

Figure 1 Digestion Complex Site Plan

After dewatering, the biosolids are land applied in Adams and Arapahoe counties. The L/EWWTP produces approximately 3,400 dry tons per year of biosolids. Almost three-quarters of the biosolids are applied to land owned by Littleton and Englewood, and the remainder is applied to private lands.

1.2.2.1 Existing Biogas System

Gas produced in the digesters is currently collected in the headspace of the operating digesters and connected to a biogas header. Gas pressure is maintained at a set point by the backpressure control valve at the waste gas flare. Pressure and vacuum relief assemblies are located on each digester roof to protect the digesters in case of a blockage in the piping. A portion of the biogas is burned to heat the primary digesters in the dual-fired boilers.

The L/EWWTP has two Jenbacher cogeneration engines and ancillary equipment, though they have not been used since 2005. Gas treatment was not installed with the cogeneration equipment, and burning the raw biogas created operational issues for the engines due to siloxane buildup. Based on the evaluation performed in the 2013 Master Plan, L/E has elected to abandon the cogeneration engines due to the high cost of maintenance (estimated to be approximately $900,000 per year for a contract services agreement).

1.2.2.2 Biogas Production and Quality

Gas production at the facility during 2016 is presented in Figure 2. This figure shows the total biogas production and biogas consumed in the boilers to heat the process and building. The remainder is flared. Based on the operating data, gas production fluctuates between approximately 400,000 and 1,000,000 cubic feet per day (cfd) with an average of 469,000 cfd. While only 1 year of data is shown, this is typical of historical plant operation.

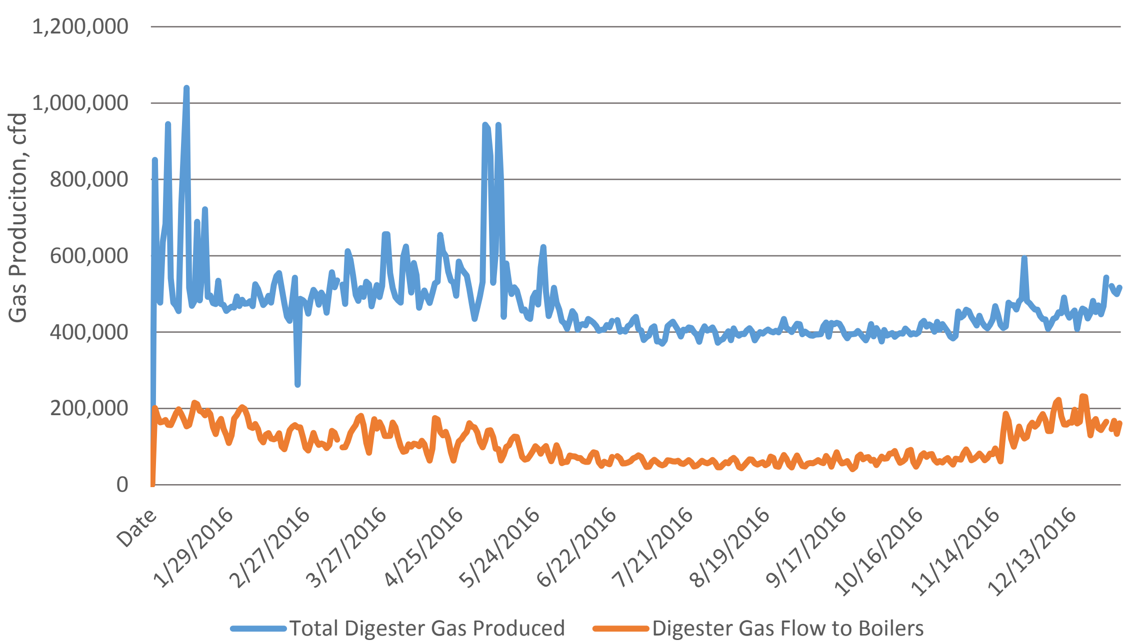

Figure 2 Historical Biogas Production

To determine the future gas flows, Carollo Engineers (Carollo) initially used a ratio of current and future average day annual influent flow projections developed for the 2013 Master Plan based on service area population projections. The Master Plan over-predicted the flow in 2015, so Carollo lowered the projection to match the growth from 2010 to 2015. Based on the revised projections, gas production is anticipated to increase from 469,000 cfd in 2015 to 556,700 cfd in 2038. Figure 3 presents both influent flow and biogas flow projections between 2015 and 2038. This increase in flow and biogas production equates to approximately a 1 percent growth of L/EWWTP's service area. Carollo estimates this growth is due to urban infill and not increasing the service area.

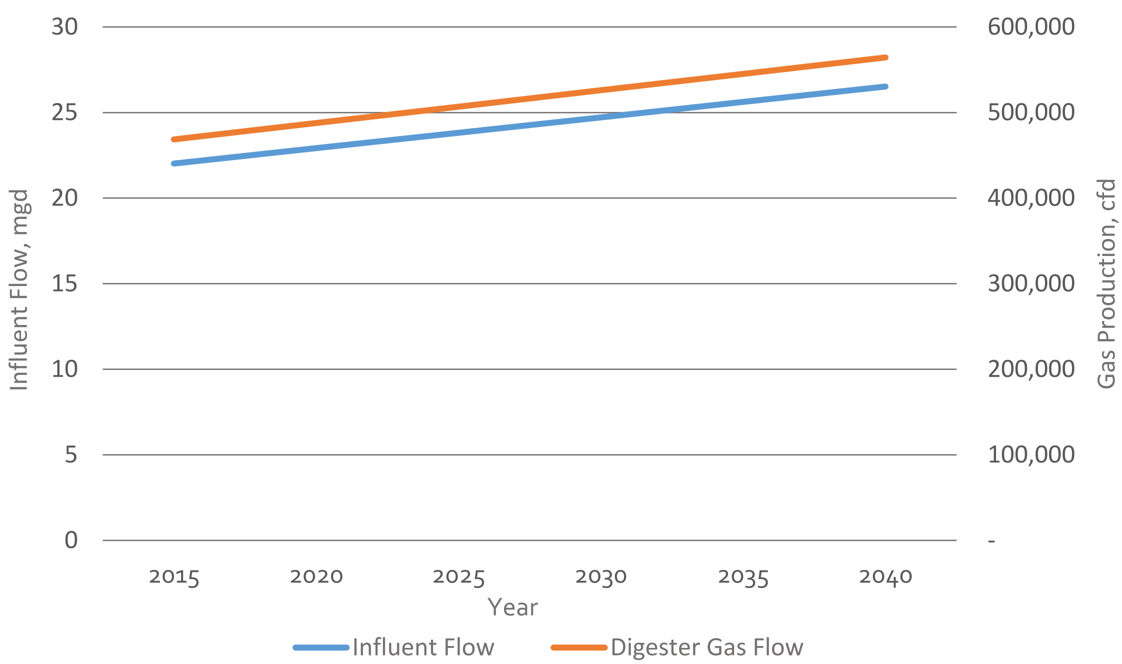

Figure 3 Influent and Biogas Flow Projections

The quality of the gas will determine the level of treatment required for the various alternatives evaluated herein. The L/EWWTP provided historical biogas quality data, including heating value, methane (CH_4) concentration, carbon dioxide (CO_2) concentration, and hydrogen sulfide (H_2S) concentration, as shown in Table 1. The L/EWWTP tests the gas roughly every 2 weeks.

Table 1 Biogas Quality

	CH_4 (%)	CO_2 (%)	H_2S (ppm)	Siloxane (ppm)	Heating value (BTU/scf)(1)
Average	58	40	157	<1	443
Maximum	59	42	231	1.3	457
Minimum	55	38	25	<1	427

Notes:
(1) Based on Carollo's experience, the heating values are lower than expected. A different calculation method used by a third party lab resulted in a heating value of 600 BTU/scf. The value used in this analysis is 550 BTU/scf, adopted from the 2013 Master Plan.
BTU = British thermal unit ppm = parts per million scf = standard cubic feet

With the exception of the heating value (explained in the table footnote), these values are all within normal ranges for a municipal L/EWWTP.

1.2.2.3 Digester Heating Requirement

The heating system comprises of three boilers, a primary heat reservoir loop and multiple secondary heat reservoir loops. As shown in Figure 2, an average of 103,900 cfd of biogas is sent to the boilers for heating, with a demand as high as 231,900 cfd in the winter months. For this evaluation, biogas consumption in the boiler of 103,900 cfd was used as the starting point in 2018. The amount of gas required was assumed to increase at the same rate the influent flow increased, to 119,700 cfd in 2038. These gas flows correspond to heat demands of 57.1 million BTUs/day and 65.8 million BTUs/day, respectively.

1.3 Biogas Utilization Alternatives Analysis

Prior to initiating this project, the L/EWWTP team evaluated a number of options to beneficially re-use the biogas produced on-site. These alternatives were compared to current operation (use biogas to heat digesters and flare excess gas) and included:

- Reinvesting in cogeneration facilities,
- Conversion of biogas to CNG for vehicle fueling,
- Conversion of biogas to CNG for pipeline injection,
- Biogas supply to local industries,
- Bioplastic generation from biogas, and
- Biosolids drying.

Based on previous experience with their cogeneration system, plant staff elected to not pursue reinvestment in cogeneration facilities. Biogas supply to local industries was deemed to be less economically favorable as compared to the conversion of biogas to CNG. Bioplastic generation from biogas was not evaluated further due to its lack of implementation at full scale. Biosolids drying was found to have a significantly higher capital cost than the other alternatives based on evaluations at other facilities, and was dropped from consideration. As a result of the L/EWWTP evaluations, the team determined that the two options to be evaluated as part of this project are as follows:

- Conversion of biogas to CNG for vehicle fueling, and
- Conversion of biogas to CNG for pipeline injection.

The sections below present the findings related to evaluating the feasibility, costs, advantages, and disadvantages of these two alternatives as compared to the project baseline.

1.3.1 Project Baseline

The project baseline represents the current operation of the L/EWWTP, for comparison to the alternatives presented herein. Under this scenario, the L/EWWTP would continue to burn the untreated biogas in the boiler to heat the primary digesters under typical operation, while flaring the excess gas in the existing waste gas burner, as described in Section 1.2. This alternative is presented as a "do nothing" alternative and would not incur additional capital or operating costs, but would not accomplish the L/EWWTP’s goals of finding a beneficial use for the biogas and creating a revenue stream.

1.3.2 Compressed Natural Gas for Vehicle Fuel

Use of biogas for the production of CNG for vehicle fuel has gained increasing interest over the past decade due to the economic benefit of offsetting vehicle fuel rather than electricity. With municipal fleet and private sector vehicles across the country converting to CNG, there is a great opportunity for collaboration by locating vehicle fueling stations near existing wastewater treatment plants and making use of an already available fuel source. While implementation of these types of projects at wastewater treatment plants is relatively new, the technology for conditioning and compressing the gas into CNG is well-established, and is currently in use at landfills across the country. Newly developed regulations and goals geared toward greenhouse gas (GHG) emission reductions are providing newfound incentives for implementing these types of projects.

Table 2 summarizes projects that have been completed or are underway to convert biogas to CNG for vehicle fuel at wastewater treatment plants in the United States.

Table 2 CNG Vehicle Fuel Project Status

Project Location	Average Dry Weather Flow	Production Since	Biogas Utilization
City of Janesville, WI	13 mgd	2012	CNG for vehicle fuel
City of Grand Junction, CO	8 mgd	2015	CNG for vehicle fuel
St. Petersburg, FL	35 mgd	2015	CNG for vehicle fuel
Napa Sanitation District, CA	9 mgd	In Progress	CNG for vehicle fuel
Columbia Boulevard Water Treatment Plant, OR	100 mgd	City Council approved; design not yet begun	CNG for vehicle fuel
City of San Mateo, CA	12 mgd	2016	CNG for vehicle fuel
City of Porterville, CA	5 mgd	Evaluation complete; design not yet begun	CNG for vehicle fuel
Petaluma, CA	5 mgd	In Design; Construction to begin in 2017	CNG for vehicle fuel

The required equipment for this alternative consists of treatment, compression, storage, and a fueling station. In order to produce CNG, the biogas is cleaned to remove H_2S, siloxanes, moisture, and the majority of CO_2, resulting in greater than 95 percent CH_4 content. After treatment, the gas is compressed and stored for use.

This system converts a majority of the gas to CNG, and the remaining gas, known as the tail gas (approximately 30 percent of the initial CH_4 content, along with the stripped CO_2 depending on treatment method) can either be flared or potentially burned in the existing boiler, either with natural gas blending or by itself. This tail gas has a heating value lower than normal biogas. Another option is to provide an extra treatment step (an additional set of membranes) for additional CO_2 removal. This increases the efficiency of the gas conditioning system from 70 percent to 95 percent, but requires a thermal oxidizing flare or similar technology for disposal of the very low BTU waste gas, since it contains mostly CO_2. For the purposes of this analysis, a dual pass conditioning system was assumed, which has a higher capital cost, but a lower overall payback period, due to the increased utilization of the digester gas.

A proposed layout of the gas conditioning skid on the L/EWWTP plant site is presented in Figure 4. The skid can be located outdoors on a concrete pad. An alternate location for the equipment could be in the existing cogeneration room, if the existing units are removed.

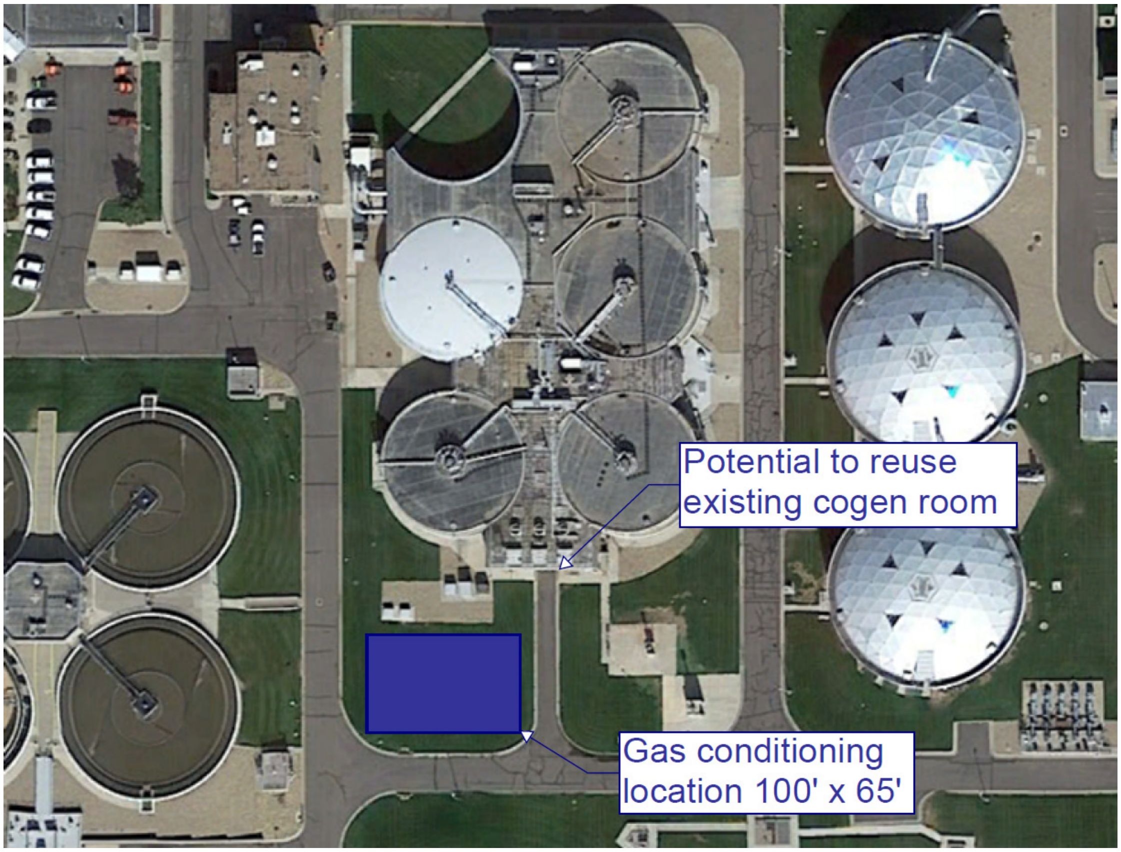

Figure 4 Proposed Gas Conditioning Skid Site Plan

A typical CNG fueling station receives natural gas from a pipeline and uses compressors to pressurize the gas to supply either fast-fill or slow-fill fueling stations. Fast-fill fueling stations compress CNG to roughly 3,000 pounds per square inch. At this pressure, it takes roughly the same amount of time to fill a CNG vehicle as a traditional gasoline or diesel powered vehicle. Slow-fill fueling stations are often used for fleet vehicles that are not in operation for a significant portion of the day. For these stations, the gas is pressurized to 2,000 pounds per square inch (psi) and is fed to the vehicles overnight so that they are ready for use the next day.

This evaluation considered several possible users that had a large fleet of vehicles that could use the CNG produced at the L/EWWTP, including the United Parcel Service (UPS), Safeway, Western Disposal, Regional Transportation District (RTD), Waste Management (WM), and Englewood Schools, among others. Englewood Fleet Services was considered, but would not have sufficient fuel usage use to make the project economically viable. Many of the potential users considered already have fueling on-site, and are not located within a reasonable distance for a pipeline to be installed between the L/EWWTP and the existing fueling station. The most feasible alternative was WM. The WM refueling and parking site is less than 3 miles from the L/EWWTP and currently has 40 CNG trucks, with plans to purchase 60 more in the future. WM operates more than 5,000 CNG powered trucks in North America, and would bring significant experience to the project.

A fast-fill fueling station closer to the L/EWWTP was briefly considered, but the production from the L/EWWTP is relatively constant throughout the day and night, and a large portion of biogas would be wasted without including significant and costly storage volume. Additionally, WM already has slow-fill fueling stations constructed at their site.

Based on conversations with WM, this analysis assumes the WM trucks drive an average of 75 miles per day and have an efficiency of 2 miles per gallon. Based on these assumptions, the fleet would require 1,500 diesel gallon equivalents (DGE) of CNG fuel per day. The equivalent BTU value, DGEs, and equivalent vehicle miles per day based on the L/EWWTP's current and future biogas production are presented in Table 3. This analysis shows that the L/EWWTP produces in excess of what is required by Waste Management's fleet. The limiting factor for WM use is their operational schedule of 5.5 days per week.

Table 3 Biogas Production Equivalents

Year	Biogas Production, cfd	BTUs Generated/Day	DGEs/Day	Equivalent Vehicle Miles/Day
2015	468,600	257,730,000	1,800	3,600
2038	556,700	306,185,000	2,200	4,400

Notes:
(1) Assumes 550 BTU/cf, 129,500 BTU/DGE, and 95% efficiency of dual pass biogas conditioning system and 96% availability.
(2) Assumes CNG sanitation vehicles achieve a fuel efficiency of 2 miles per DGE.

The fueling station would be designed to use either CNG from the L/EWWTP or natural gas (as it is currently operated). The fuel system would utilize a pressure regulating valve so that CNG is used before the currently supplied natural gas. During times when production exceeds demand, the excess can either be stored, or flared if storage is full. Gas production in excess of use and storage can be used in the boilers.

The WM fleet is currently based at 2400 W. Union Avenue, Englewood, CO 80110. The team evaluated the construction of a pipeline between the L/EWWTP and WM, likely routed down Santa Fe Drive, as shown in Figure 5. The cost of the pipeline itself is anticipated to be roughly $1 million dollars for material and installation costs (trenching and tunneling under the South Platte River). The routing of this pipeline, although small in diameter, poses concerns with respect to coordination with landowners and permitting, given that it would be routed through a congested area and below the South Platte River. This could add project complexity and result in schedule delays.

Another concern with this alternative (beyond routing the pipeline) is that once a pipeline is constructed, the L/EWWTP is tied to WM without other customers to sell to. In the future, L/E could install a CNG fueling station for the public along Santa Fe Drive, but the demand of this fueling station is unknown, and would likely be significantly lower than the demand from WM. One advantage of this alternative is that it would meet the L/EWWTP’s strategic plan objective of creating regional partnerships to benefit members of the community.

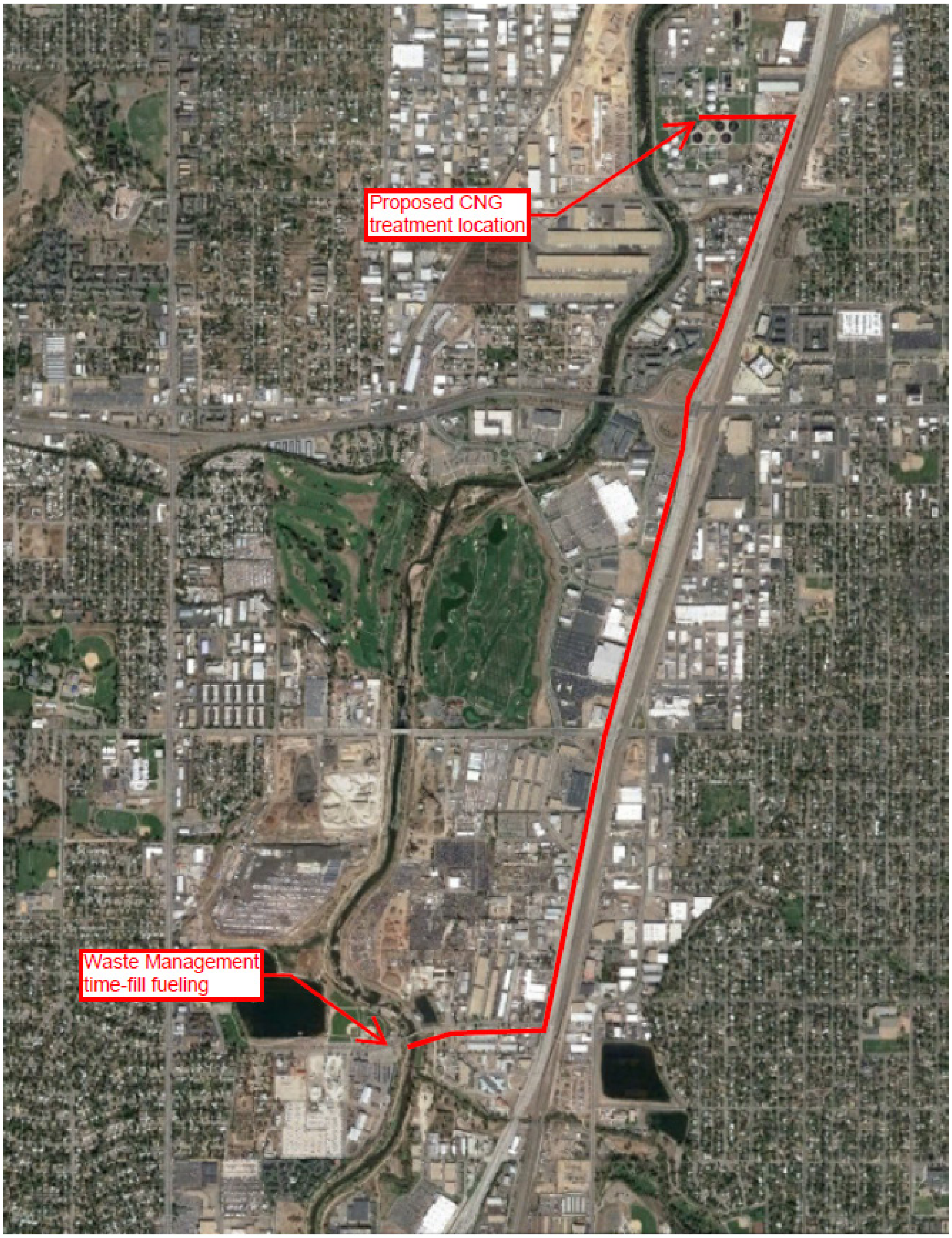

Figure 5 Potential Routes for CNG Pipeline to WM Fueling Station

1.3.3 Pipeline Injection

Another use of CNG is direct injection into a pipeline for a third party vehicle fuel use. This alternative requires additional cleaning of the biogas beyond CNG vehicle fuel standards, but eliminates the need for storage and the concerns over finding sufficient consistent demand for the produced gas. Table 4 summarizes projects that have been completed or are underway to convert biogas to CNG for pipeline injection at wastewater treatment plants in the United States.

Table 4 Pipeline Injection Project Status

Project Location	Average Dry Weather Flow	Production Since	Biogas Utilization
Point Loma, CA	240 mgd	2012	Pipeline injection
Clean Water Services, OR	65 mgd	2017	Pipeline injection
Raleigh, NC	44 mgd	Construction to begin in 2018	Pipeline injection
Des Moines, IA		Construction to begin in 2017	Pipeline injection
South Bend, IN	48 mgd	Completion expected September 2017	Pipeline injection

For this alternative, the biogas is treated to remove siloxanes, H_2S, CO_2, and moisture, undergoes compression, and is then injected into a natural gas supply pipeline.

Pipeline injection requires a similar treatment of the gas as CNG for vehicles, but would require an extra treatment step (an additional set of membranes) for additional CO_2 removal. This would also require a thermal oxidizing flare or similar technology for disposal of the very low BTU waste gas, since it contains mostly CO_2. The proposed location of this gas conditioning system is the same as that of the CNG fueling option, as shown in Figure 4. The current and future production of CNG would be the same as that of the alternative above, shown in Table 3.

Carollo identified the Xcel Energy, the local natural gas utility, as the owner of the local natural gas pipelines. Xcel indicated that they are amenable to receiving the treated gas, providing it meets their Colorado Gas Tariff renewable natural gas (RNG) specifications, shown in Table 5. On behalf of L/EWWTP, Carollo filled out Xcel's "RNG Evaluation Form" and in response, Xcel has shown support for the project and will work with L/EWWTP to form an agreement. Xcel has indicated that the L/EWWTP also must meet several additional "tariff silent" requirements, included in Appendix A. Based on conversations with Unison Solutions, a manufacturer of biogas conditioning systems, these quality requirements can be met. Xcel Energy also confirmed the best location to connect to the system is on the northern boundary of the plant site to an existing natural gas pipe that operates at 150 psi.

Table 5 Xcel RNG Biogas Quality Requirements

Constituents/Properties	Limit	Units
Higher Heating Value (HHV)	965-1,100	BTU/scf
Wobbe (based on HHV)	1,185-1,285	
Carbon Dioxide (mol %)	3.0	mol %
Oxygen	2.0	mol %
Total Inerts	14.3	mol %
H_2S)	0.25 (4)	gr/Cscf (ppmv)
Total Sulfur	5.0 (85)	gr/Cscf (ppmv)
Hydrocarbon Dew Point Cricondentherm	15	degrees F
Water Vapor Content	3	lb/MMscf
Dust, Dirt, Scum, and Other Solids	Free of	
Water and Hydrocarbons in Liquid Form	Free of	
Temperature	32-110	degrees F

Xcel Energy requires equipment for injection into their system, including a gas chromatograph, flowmeter, regulator, remote terminal unit (RTU), gas odorizer, emergency shut-off valve, and other ancillary equipment. The installed cost of the equipment was estimated to be $1,050,000. This equipment will be designed and installed by Xcel Energy.

The principal benefit of pipeline injection is that 100 percent of the generated biogas can be sold to offset vehicle fuel, instead of being limited by Waste Management's lack of nighttime and weekend operation.

1.4 Incentives/Grants for Biogas to Transportation Fuel

With increasing public pressure to reduce the country's reliance on non-renewable vehicle fuels, several programs, and incentives have been designed to offset fossil fuel use and decrease GHG emissions.

1.4.1 Environmental Protection Agency's Renewable Fuel Standard Program

The Environmental Protection Agency's (EPA) Renewable Fuel Standard (RFS) Program was created under the Energy Policy Act of 2005, (https://www.epa.gov/renewable-fuel-standard-program), and established the first renewable fuel volume mandate in the United States. The program requires oil and gas producers to purchase specified amounts of fuel credits each year to increase the amount of renewable fuel used. Each 77,000 BTUs of gas used for vehicle fuel generates a renewable credit with a specific identification number, named the Renewable Identification Number (RIN).

The RFS program defines four types of renewable fuels: cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel. As of 2014, the RFS program allows digester biogas from municipal wastewater treatment facility digesters as a transportation fuel feedstock. The biogas is designated as a "cellulosic" (D3) feedstock, which carries the greatest RIN value of the four categories.

The mandated quantities of renewable fuel volumes have been set through 2022, as shown in Figure 6. Beyond 2022, fuel volume mandates will be set by the EPA administrator.

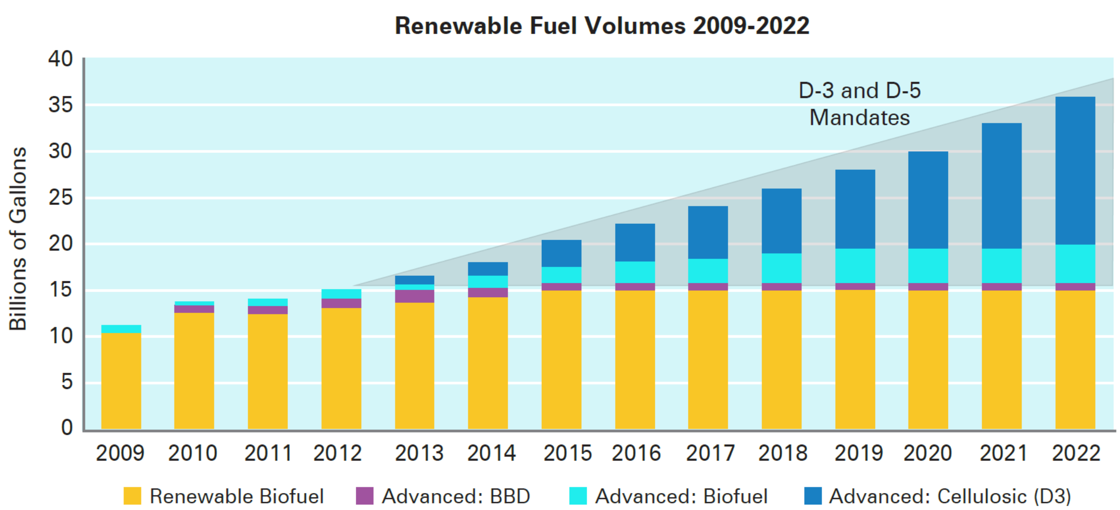

Figure 6 Renewable Fuel Volume Mandates

RINs are traded on the open market, and their value is dependent upon the price of oil and the renewable volume obligation, which is the amount of RINs obligated parties have to purchase. When D3 RINs were first introduced into the market 3 years ago, they had a value of approximately $1.00 per RIN. D3 RINs are currently trading for $2.50, with a 3-year historical average of $1.78. As demand for RIN credits associated with cellulosic biofuels grows, the expectation is that RINs will have an increasing market value over time. For the purposes of this evaluation, the currently traded value of $2.50 was used. Figure 7 presents the historical average RIN value for D3 RINs from 2015 through present day.

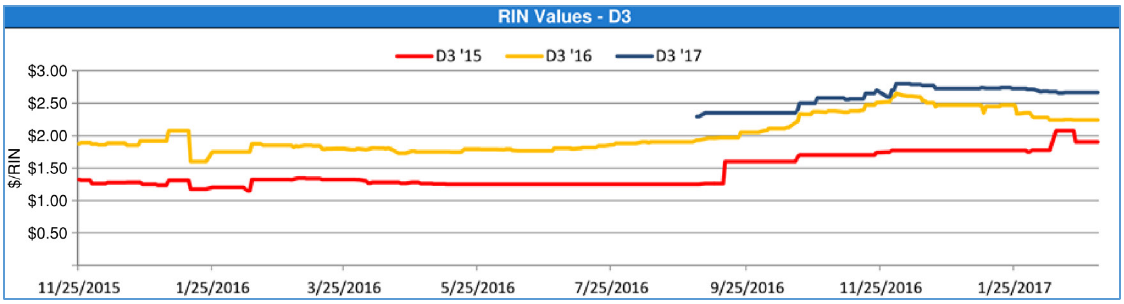

Figure 7 Historical D3 RIN Values

In order to become a RIN producer, the L/EWWTP must be certified with the EPA. This is typically done by a third-party carbon offset broker. Carbon offset brokers can provide RIN registration and ongoing reporting and management. The carbon offset brokers also handle the sale of RINs to producers. In exchange, they receive a management fee based on an agreed upon percentage of the RIN value, anticipated to be 20 percent for this size of project. For pipeline injection projects, the carbon offset brokers also manage the sale of the injected CNG.

Another option is for an obligated party (i.e., oil and gas producer) to purchase the RINs directly from the L/EWWTP. L/EWWTP and Carollo have discussed this with British Petroleum, and they have expressed interest in the project.

Both options result in the sale of the CNG and RIN credits, and would include similar amounts of work for L/EWWTP. Differences could include the length of contract, contractual obligations, and pricing structure. A priority for bidding the project would be determining an effective way to compare the two options and the risk/value propositions associated with their contract structures.

1.4.2 ALT Fuels Colorado Program

The Colorado Energy Office (CEO), the Regional Air Quality Council (RAQC), and the Colorado Department of Transportation (CDOT) provide grants through the ALT Fuels Colorado program for a variety of alternative fueling infrastructure, including new, publicly accessible CNG fueling equipment; co-located electric vehicle charging and propane station equipment at funded CNG stations; and CNG, propane, and electric vehicles. The ALT Fuels Colorado grant program is a partnership between the CEO and the RAQC, created to award grants for partial funding of CNG fueling station equipment, and co-located electric vehicle charging and propane auto gas station equipment. ALT Fuels Colorado will distribute approximately $30 million over 4 years (between 2014 and 2017) to incentivize adoption of alternative fuel vehicles. Since Waste Management already has fueling stations and pipeline injection does not include fueling infrastructure, ALT Fuels grants for a fueling station will likely not apply. In addition, it would be difficult to get funding through this program since it is anticipated to conclude at the end of this calendar year.

1.5 Gas Conditioning

Both of the alternatives above require gas conditioning treatment to remove impurities such as H_2S and siloxane compounds, followed by removal of the majority of the CO_2, resulting in greater than 95 percent CH_4 in the gas. Conversion of biogas for pipeline injection requires a second step to remove additional CO_2, resulting in greater than 99 percent CH_4 in the gas. The gas conditioning systems use well-proven technologies to remove the undesired constituents. A typical gas treatment schematic for CNG and pipeline injection is presented in Figure 8.

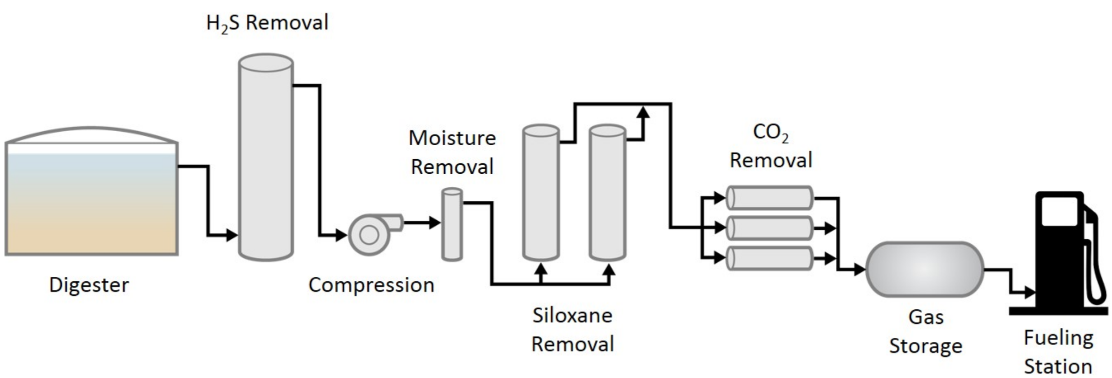

Figure 8 Typical Treatment Skid for CNG

Treatment processes for biogas typically fall into two groups: physical or chemical/biological removal. Water vapor, CO_2, and particulates are removed by physical processes, while volatile organic compounds (VOC), halogenated organics, H_2S, and siloxane compounds are removed by either chemical or biological treatment. The various compounds and their treatment systems are explained below.

1.5.1 Hydrogen Sulfide

H_2S is a highly reduced compound that readily binds with most metals and is abundant in biogas. During combustion, H_2S reacts with oxygen creating sulfur, sulfur dioxide (SO_2), sulfite (SO_3), and sulfate (SO_4). All of these compounds are known as SOx, and they are regulated as air pollutants. Additionally, oxidized sulfur compounds will react with water to form sulfuric acid. Sulfuric acid corrodes downstream equipment, resulting in increased maintenance and reduced service life. H_2S can be removed from biogas by the use of iron salt addition to the sludge, iron adsorption, caustic scrubbing, or biological treatment.

1.5.1.1 Iron Salt Addition

The use of iron salts for mitigation of H_2S is widespread among wastewater utilities and is currently used at the L/EWWTP. Both ferric chloride and ferrous chloride can be added directly to the anaerobic digesters. Typical dosage rates for ferric chloride and ferrous chloride are 3.2 and 3.7 grams per gram of H_2S. Other benefits from iron salt addition to anaerobic digesters include precipitation of phosphorus and increased degradability of grease. Disadvantages of iron salt addition include increased sludge volumes and the potential for formation of vivianite scale in piping, heat exchangers, and digesters.

1.5.1.2 Iron Adsorption

The oldest commercial process for removing H_2S from gas is "iron sponge" which has been in use for more than 100 years. Iron sponge normally has the lowest initial cost of all commercial processes. The iron sponge concept is quite simple: hydrated iron oxide is impregnated onto redwood chips, creating a reactive media for the H_2S. The spent wood chip media is non-hazardous, must be replaced, and can be used as a soil fertilizer. Servicing typically requires that spent wood chip media be removed with 6,000 psi water jet, shovel and/or be vacuumed out.

An alternative form of solid media H_2S removal system is termed "sulfa treat" and uses iron-based chemistry but uses a different media base. Sulfa treat is a dry, free-flowing iron oxide-based media that selectively removes H_2S and some light mercaptans. The solid, clay-like media is an inorganic ceramic coated material coated with an iron oxide. The iron oxide reacts with the H_2S to form iron pyrite.

Adsorption media firms have developed proprietary media that more effectively remove H_2S while increasing the capacity of the media. These newer media generally have higher capital cost but require less frequent replacement.

1.5.1.3 Water Scrubbing (Caustic Scrubbers)

Caustic scrubbers are recirculating liquid packed towers, which use elevated pH to transfer H_2S from the gas stream to a sodium hydroxide (NaOH) solution. This type of system utilizes a large quantity of water in a single pass arrangement. If a secondary effluent water source can be readily obtained and if the water can be returned downstream of the secondary process, this method can be cost effective. Removal of approximately 80 percent of the sulfur compounds can be expected from such systems. This method is typically economically feasible only for large gas flow rates (larger than 1,000 cfm).

1.5.1.4 Biological Treatment

Biological treatment systems are now coming onto the market for removal of sulfur compounds from biogas. These systems are nearly identical to water scrubbing systems except that the system utilizes a much lower amount of water in a recycle system. Biological systems consist of a packed tower in which biogas travels upwards through packing while recirculated water is sprayed down onto the packing. Biological growth occurs on the packing, which reduces the sulfur compounds in an identical manner to biological odor scrubbers. This type of system utilizes a very small quantity of secondary effluent water. Removal of approximately 95 percent of the sulfur compounds can be expected from such systems. As sulfur compounds are reduced by biological treatment, no significant sulfur loading would occur in the plant.

1.5.1.5 Recommended H_2S Treatment

Due to the current iron salt addition and resulting relatively low H_2S concentrations in the L/EWWTP's biogas, the recommended treatment method is media based adsorption. The hydrogen sulfide concentrations after the iron salt addition are not high enough to warrant a biological system and the flows are not high enough to make a caustic scrubber feasible.

The exact type of media will be determined along with the system's manufacturer and will consider effectiveness, capacity, price, and maintenance concerns, such as ease of removal and replacement.

1.5.2 Moisture

The common and recommended moisture removal treatment is a refrigeration process that chills the gas, condensing the moisture. Upstream of the cooling portion of treatment, a coalescing filter removes any particles in order to maintain the effectiveness of the heat exchangers. Glycol is air-cooled using a refrigeration unit and is circulated through a heat exchanger to cool the gas. Once the gas is below the dew point, the moisture condenses and drops out, to either be automatically removed by a drip trap or condensate accumulator. The gas leaves the process and is compressed to reheat and pressurize the gas. This is a very commonly used and well-proven system that operates automatically with minimal maintenance.

1.5.3 Siloxanes

Siloxanes are cyclic organic silicon monomers used in the manufacture of personal hygiene, health care, and industrial silicon products, and are typically found in biogas at varying levels. Combustion of biogas containing siloxanes can result in deposits of silica residue on equipment surfaces, impairing performance, and significantly increasing system maintenance.

There are several generally accepted siloxane removal methods: single-stage refrigeration, two-stage refrigeration, and adsorption. Adsorption is the recommended method for this project, because of its ability to reliably remove the siloxanes down to the required values for either cogeneration or CNG. Adsorption typically includes an upstream single-stage refrigeration/chiller dryer to remove water and some contaminants. The siloxanes are removed from the biogas by adsorption onto the surface of the desiccant media such as silica gel. Siloxane adsorption can be designed to remove siloxanes down to the minimum detection limit.

1.5.4 Carbon Dioxide

The most commonly used and recommended CO_2 removal treatment is a membrane separation system. The gas is pressurized and the CH_4 is retained on the membrane while the CO_2 passes through as tail gas. Some CH_4 also passes through into the tail gas, which means the gas needs to be flared. A second membrane step can be added to retain more of the CH_4 and create a more pure product (required for pipeline injection). This process requires a thermal flare since the waste gas does not have a high enough BTU value to be burned in a traditional flare.

1.5.5 Summary of Manufacturers

Table 6 summarizes the constituents in the raw biogas and the manufacturers that provide the recommended equipment required to remove them. Many of the manufacturers can provide a packaged skid that includes each of the systems below.

Table 6 Summary of Conditioning Equipment Manufacturers

Constituent	Recommended Treatment Method	Removal Equipment Manufacturers
H_2S	Adsorption	Varec, Clean Methane Systems, ESC, Marcab, MV Technologies, Unison, Biorem, Venture
Moisture	Refrigeration	Clean Methane Systems, ESC, Parker, Perennial Energy, Unison, Venture
Siloxane	Adsorption	Clean Methane Systems, ESC, Marcab, Theia Air, Unison, Venture
CO_2	Membrane Separation	Air Liquide, Unison

Figure 9 shows an example gas conditioning system, located at the Persigo WWTP in Grand Junction, Colorado.

Figure 9 Digester Gas Conditioning System in Grand Junction

1.6 Biogas Storage

Storage for CNG systems is often required due to the constant production of biogas and intermittent fueling periods. For a fast-fill station, high-pressure storage is required in order to have CNG on-demand. A larger amount of storage results in higher utilization, since overnight production can be stored for daytime dispensation (or vice-versa for slow-fill stations), since gas must be flared when the storage is full. Figure 10 shows an example bank of high pressure storage tubes that would be included for the CNG fueling alternative.

Figure 10 High Pressure Storage Tubes for CNG

While storage is not required for slow-fill stations, it is recommended for the WM alternative to increase utilization. A portion of the gas produced during the day will be used in the boilers, and the remainder will be stored. If the storage is full and production exceeds demand, the remainder will be flared using the existing flare. At night, the sanitation trucks will be filled from both the production of biogas and from storage.

A storage vessel or bank of storage vessels containing roughly half of the L/EWWTP's production, 800 DGE, is recommended for the CNG option. This will maximize the utilization of biogas use by storing gas produced during the day and dispense the gas required to fuel the trucks at night.

Storage is not required for the pipeline injection alterative, since CNG would be injected into the pipeline at the same rate it is produced.

1.7 Economic and Non-Economic Comparison

The following alternatives were identified as feasible for this facility based on the preliminary assessment and were further evaluated to determine capital and life cycle costs. All of the alternatives were compared to the existing operation, which burns a portion of the biogas to heat the digesters and the remainder is flared.

- Alternative 1: Conversion of biogas to CNG for vehicle fueling.
  - A vehicle fueling installation would include a new gas conditioning system to convert the plant's biogas into vehicle fuel quality natural gas (CNG). An approximately 3-mile pipeline running from the L/EWWTP to the Waste Management fueling site to the south would be built to convey the gas.
- Alternative 2: Conversion of biogas to CNG for pipeline injection.
  - Pipeline injection will include installation of a new gas conditioning system to convert the plant's biogas into pipeline quality CNG. The CNG would be sold to the market and used to generate and sell renewable credits.

1.7.1 Capital Cost Evaluation

Carollo's cost estimating software was utilized to develop capital cost estimates for the alternatives listed above and represents a Class 4 Estimate based on the American Association of Cost Engineering (AACE) classification. Equipment quotes were provided by Unison, a manufacturer of gas conditioning and fueling systems.

Capital costs presented herein are escalated to the mid-point of construction (assumed to be middle of 2018). Assumptions and allowances for the capital costs are presented in Table 7.

Table 7 Design Criteria and Financial Assumptions

Criteria	Assumption Used
Escalation rate	3%
Electrical, Instrumentation & Controls Allowance	15%
Contingency	20%
General Contractor Overhead, Profit, Bonds, and Mobilization	15%
Engineering, Legal, and Administrative Fees	15%

A summary of the project costs is shown in Table 8. Detailed project cost estimates are provided in Appendix B.

Table 8 Estimated Project Costs

Alternative	Total Project Cost
1. Vehicle Fuel	$8,423,000
2. Pipeline Injection	$7,500,400

1.7.2 Life Cycle Cost Evaluation

A life cycle cost for both options was developed, which evaluated the costs and revenues for each option over the estimated life of the equipment (assumed to be 20 years). Assumptions used for the life cycle cost analysis are presented in Table 9.

Table 9 Design Criteria and Financial Assumptions

Criteria	Assumption Used
Inflation Rate for capital and Operation and Maintenance (O&M) Costs (fuel, electricity)	3%
Gross Discount Rate	4%
Biogas HHV, BTU/scf	550
Gas Conditioning System Availability Percentage	96%
O&M Cost for Dual Pass Gas Conditioning System , $/GGE	$0.54
Natural gas cost, $/therm	$0.53
RIN Credit, $/RIN	$2.50
CNG Sale Price $/therm	$0.20

Notes:
GGE = gasoline gallon equivalents

To evaluate the benefits and costs of each alternative, the projected capital cost, O&M costs, and anticipated revenues were calculated. The total net present value was then calculated for each alternative. A summary table presenting the life cycle cost for each alternative is shown in Table 10.

Table 10 Net Present Value Summary

Alternative	Vehicle Fuel	Pipeline Injection
Estimated Capital Cost	($8,423,000)	($7,500,400)
Averaged Annual (Costs)/Revenues		
Revenue for CNG Sale	$604,200	$285,800
Revenue for RIN Credit	$1,686,400	$2,474,500
Natural Gas Costs	($23,800)	($188,600)
O&M Costs	($457,900)	($623,500)
20-Year Present Value of (Costs)/Revenues		
Revenue for CNG Sale	$7,526,400	$3,560,600
Revenue for RIN Credit	$21,828,200	$32,028,700
Natural Gas Costs	($296,200)	($2,348,900)
O&M Costs	($5,703,400)	($7,766,600)
Total 20-Year Net Present Value	**$14,932,000**	**$17,973,400**
Payback Period (years)	**5**	**4**

Figure 11 presents a graphical representation of the capital cost and life cycle revenue of each alternative.

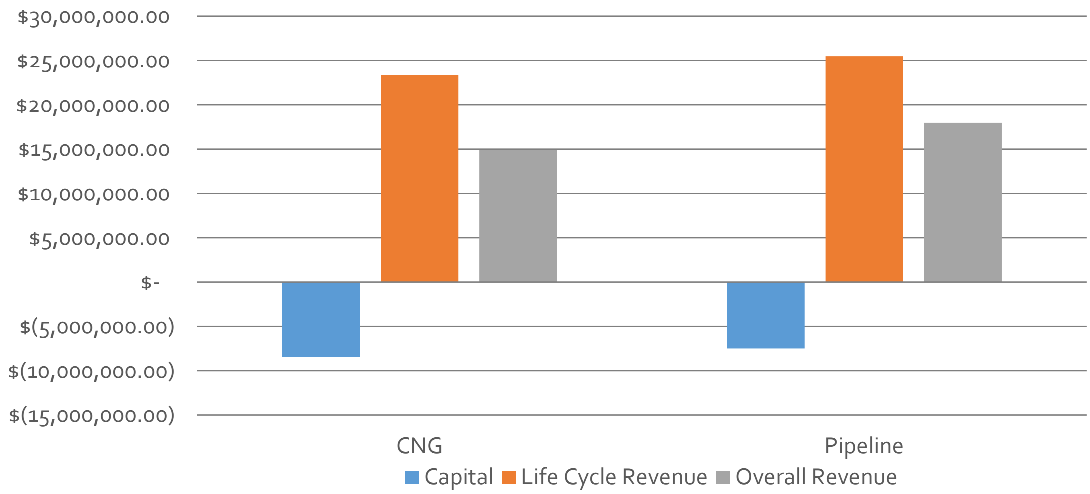

Figure 11 Summary of Capital Costs and Life Cycle Revenue

The pipeline injection alternative, which includes a dual-pass gas conditioning skid and connection to the Xcel pipeline along the northern border of the plant, has the highest net present value. Based on the revenue generated and the capital cost estimates, this alternative has a 4-year payback based on the assumptions listed above. This alternative would be able to utilize all of the produced biogas. This option would cost the L/EWWTP $7.5 million for the gas conditioning and compression equipment, pipeline through the plant to the Xcel pipeline, and required Xcel energy monitoring equipment, and would generate approximately $18 million in revenues over a 20-year period.

1.7.3 Non-economic Considerations

Each of the alternatives was evaluated against the project goals and selected non-economic criteria to determine the best fit for the L/EWWTP. Table 11 presents non-economic advantages and disadvantages for each alternative.

Table 11 Non-Economic Comparison of Alternatives

Alternative	Advantages	Disadvantages
Conversion of Biogas to CNG for Vehicle Fueling	• Development of renewable energy product • Creation of a regional partnership to benefit members of the community • Ability to heat the digester with excess biogas	• Project risks associated with pipeline routing • Project risks associated with contracting with a single entity for biogas use • Longer time to market as compared to pipeline injection
Conversion of Biogas to CNG for Pipeline Injection	• Development of renewable energy product • Higher utilization of biogas as compared to vehicle fueling • Higher reduction in GHG emissions • Shorter time to market as compared to pipeline injection • Cleaner gas provides off-ramp for future technologies	• More stringent gas quality requirements as compared to vehicle fueling

1.7.3.1 Greenhouse Gas Emissions

The L/EWWTP has a Strategic Plan Purpose Statement that reads, "Protection of Public Health and the Environment." Both of the evaluated projects will reduce the amount of vehicle miles powered by non-renewable sources, curbing GHG emissions.

To quantify the reduction in GHG emissions, a GHG inventory tool was developed for this project. GHG emission reduction can come from directly reducing GHG emissions by consuming less, or from increasing GHG offsets, which provide a positive contribution to net GHG emissions. Quantifying GHG emissions allows utilities the opportunity to plan the most cost-effective means of managing and reducing GHG emissions (or increasing offsets) while minimizing fossil fuel-based energy use and maximizing resource recovery.

Six GHGs have been prioritized for GHG inventory purposes, based on each gas' capacity to absorb and reradiate heat, and thus contribute to climate change. These GHGs include CO_2, CH_4, nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6). Of these, CO_2, CH_4, and N_2O are considered relevant for wastewater treatment emissions and are the focus of the inventory. To account for the variation in the ability for each gas to absorb and reradiate heat, Global Warming Potentials (GWP) are used to relate gases to CO_2 on a mass basis (e.g., carbon dioxide equivalence or CO_2e). An assumption of the time horizon must be made to generate meaningful emissions estimates when selecting GWPs. The typical time horizon selected is 100 years. Based on this time horizon, CH_4 and N_2O are estimated to have 25 and 298 times the capacity to absorb and reradiate heat relative to CO_2, respectively. In addition to the GWPs, a combination of widely accepted, peer-reviewed protocols and emission factors were used to estimate the GHG emissions, as summarized in Table 12.

Table 12 Factors Used to Calculate GHG Emissions from Biogas Production and Reuse

Description	Units	Value	Source
Biogas HHV	BTU/scf	550	L/EWWTP
Colorado Average Natural Gas HHV	BTU/scf	1,060	U.S. Energy Information Administration, 2015
Biogas Combustion	kg CO_2/MMBtu	52.07	40 CFR 98.33 and Subpart C
	kg CH_4/MMBtu	0.0032	
	kg N_2O /MMBtu	0.00063	
Natural Gas Combustion	kg CO_2/MMBtu	53.06	40 CFR 98.33 and Subpart C
	kg CH_4/MMBtu	0.001	
	kg N_2O /MMBtu	0.0001	
DGEs	BTU/DGE	129,500	NAFA Fleet Management Association, 2010

GHG emissions and offsets were evaluated for the two scenarios described above and compared against the project baseline. The project baseline of reusing biogas for heat provides an offset of 1,539 metric tons of CO_2e annually. Repurposing biogas to fuel vehicles increases GHG offsets to 5,386 metric tons of CO_2e annually. If the biogas is sent to pipeline injection, GHG emission offsets increase even further to 6,855 metric tons of CO_2e per year. A comparison of these offsets is shown in Figure 12.

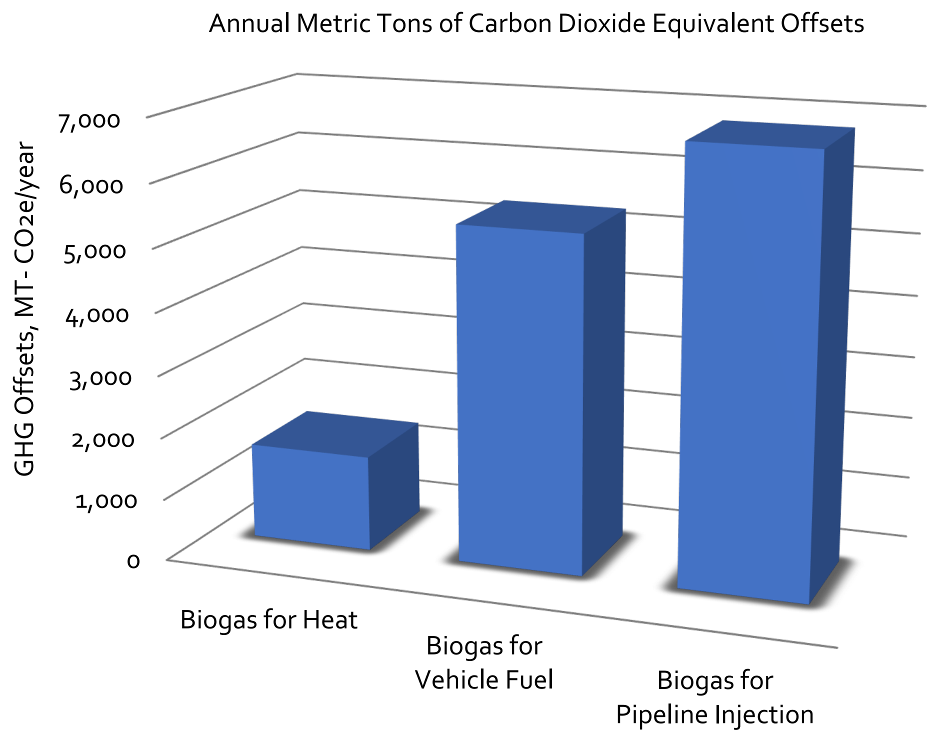

Figure 12 GHG Offsets Based on Type of Biogas Reuse

1.8 Financing and Procurement Options

The L/EWWTP has multiple options to procure and finance the gas cleaning equipment and complete the design and construction of the facilities to begin generating revenue. These options need to be consistent with the L/EWWTP's budgeting and procurement procedures. During the next phase of design development, the project team will further evaluate the financing options and develop recommendations. The various financing options include:

1. **Self-Financed:** The Cities of Littleton and Englewood would provide the capital improvements funds for the design and construction using wastewater rates and existing financial reserves. This type of financing provides the best financial returns and maintains maximum control; however, it is only feasible if the funds are available.
2. **Financial Institutions:** A bank or private equity loan could be obtained by the Cities of Littleton and Englewood to cover the capital costs and payment would be spread out over multiple years. This would reduce the immediate financial impacts and would defer payments out for a period of time which would be off-set by revenue produced.
    a. A subset of a private equity loan would be a tax-exempt loan, which is used by many Colorado cities and regulated by the State of Colorado. This type of loan approach has been part of the State statutes for over 40 years. Using a tax-exempt loan allows the City to leverage capital at a low cost of borrowing and each year, the loan is re-approved. If the market changes were significant, L/EWWTP could have the borrower possess the digester cleaning equipment and sell it on the open market. This is a very low cost option, which still provides high return on the investment and presents a balanced approach to economic viability risks associated with the RINs credits.

3. **Municipal Tax-Exempt Bonds:** L/EWWTP and the Cities of Littleton and Englewood could elect to issue municipal bonds to fund the capital investment. This option would raise money and spread out the re-payment over a period of time. This type of funding approach was not recommend for further analysis as it takes significant time and cost to develop a bond issuance, including potential voter approval. With other existing loans and the possibility of future bond issues to cover capital expenditures, Carollo believes other options are more viable.
4. **Third-Party Contracted Financing**: L/EWWTP could partner with a third-party entity and establish a power purchase agreement. This agreement would cover the financing and L/EWWTP would be provided a royalty or lease payment for the duration of the contract. The third-party entity could be a private equity firm, an equipment provider, or other energy company. Typically, these types of agreements require a long-term commitment (greater than 10 years) from L/EWWTP and include performance guarantees. There is still a beneficial financial return on the investments; however, this approach will typically provide 30 to 50 percent less return than the first two options. Using a power purchase agreement also can be challenging since digester gas quantities and qualities may change as L/EWWTP explores other improvements to maximize renewable resource values. Carollo recommends that this option be further evaluated during the next phase of the project.

Based on discussions with L/EWWTP staff, the most viable option for financing the project appears to be borrowing the capital cost money from a financial institution. However, this approach needs to be confirmed with management from L/EWWTP, and the Cities of Littleton and Englewood. A sensitivity analysis on the interest rates and terms has been provided below.

In addition to financing options, different procurement options are also viable for this project. The procurement options which were considered for this project include:

1. **Design-Bid-Build (DBB):** L/EWWTP would contract with a consulting engineer who would develop the technical design documents and serve as the Owner's representative during construction. The biogas conditioning equipment package would likely be pre-selected based on qualifications and pricing. The construction contractor would be selected based on a competitive bidding process.
2. **Construction Management at Risk (CMAR):** L/EWWTP would contract with a consulting engineer to complete the technical design documents and serve as the Owner's Representative during construction. The equipment package would likely be pre-selected based on a qualifications and price based proposal. The construction manager at risk would be selected at the 60-percent design level to provide value engineering and constructability support during the design and then complete the construction. The CMAR selection could be based on qualifications and price based proposal.
3. **Design-Build (DB):** L/EWWTP would hold one contract with a design and construction team. This team would execute the technical design documents, equipment procurement and construction services. In addition to the DB team, L/E may choose to hire an Owner's Advisor to assist with procurement, contract management, and technical input.

Based on the project scope and intent of L/E staff for this project, an approach similar to the CMAR option above would be the best suited for this project. The CMAR approach will shorten the procurement schedule and provides time for constructability reviews and value engineering input. These are elements are important for L/E as time to market and maintaining budget and control are critical objectives to achieving profitability quickly.

1.9 Summary and Recommendations

After evaluating both economic and non-economic considerations, including capital and life cycle impacts, Carollo recommends proceeding with pipeline injection alternative. The L/EWWTP's digestion process will not change, and the existing dual fuel boilers will remain in use, fully fueled by natural gas.

The gas conditioning skid is recommended to be installed to the south of the current digesters and cogeneration engine room. The pipeline routing to convey the treated gas to the northern boundary will be finalized during design. Xcel's monitoring equipment will be installed in an enclosure at the northern boundary of the plant with an internal fence and Xcel access gate from the outside. An example of the site plan is shown in Figure 13.

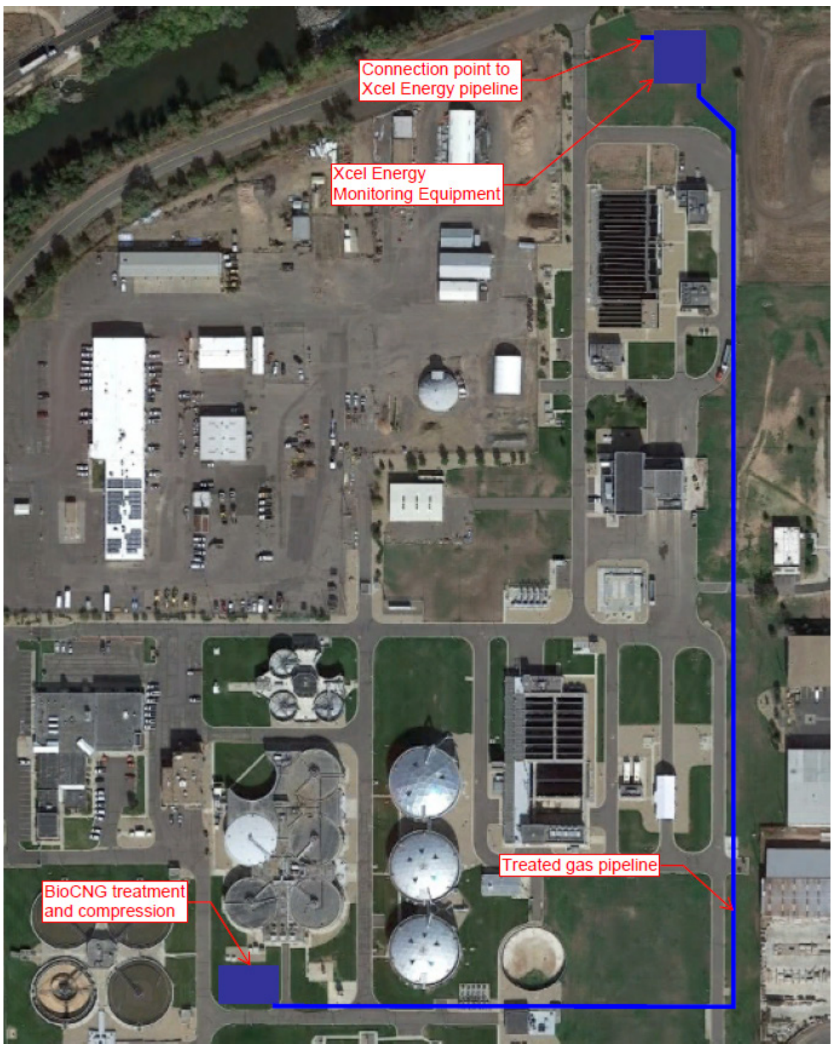

Figure 13 Future Site Plan

1.9.1 Sensitivity Analyses

Carollo performed two sensitivity analyses to evaluate the possible outcomes of this project. The first was to look at the changes in RIN values and the second was an analysis of different financing options.

1.9.1.1 RIN Value

Since the RIN value has the largest impact on the 20-year net present value of the alternatives, a sensitivity analysis was performed on the pipeline injection alternative to determine a reasonable bandwidth of costs over a 20-year period. The analysis assumes the current RIN value of $2.50 for the baseline case and all RIN values increase with inflation at 3 percent per year. Carollo performed a sensitivity analysis looking at RIN value scenarios shown in Table 13. Table 13 and Figure 14 present the results of this analysis.

The analysis illustrates that for all likely scenarios, the pipeline injection alternative will have generated significant revenue and positive net present value for L/E.

Table 13 Net Present Value at Varying RIN Values

RIN Value	Timeline	20-Year Net Present Value
$1.78/RIN, $0/RIN	2019-2022 2023-2038	($8,270,600)
$1.78/RIN	2019-2038	$8,749,000
$2.50/RIN (baseline case)	2019-2038	$17,973,300
$3.00/RIN	2019-2038	$24,379,000

Figure 14 shows that there is no payback if RIN credits drop to $0 in 2023 due to change at EPA. If this occurs, L/EWWTP should use the exit strategy approaches listed below.

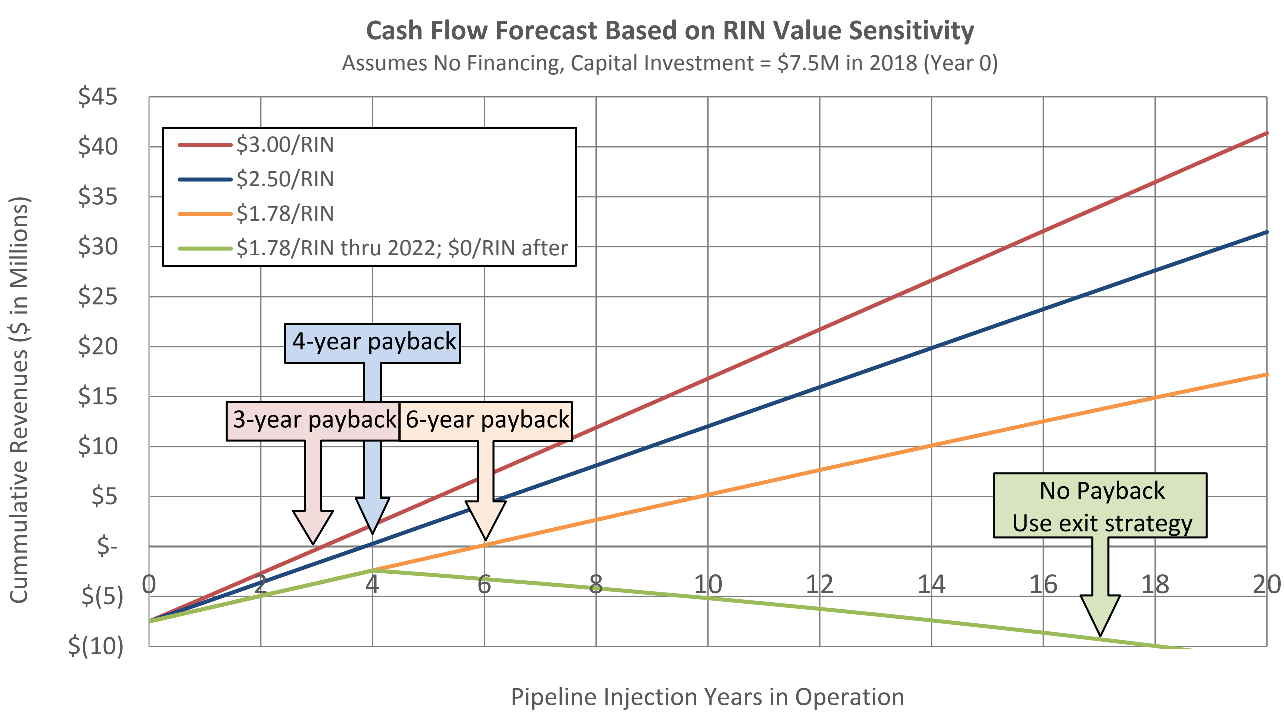

Figure 14 RIN Pricing Sensitivity

1.9.1.2 Financing Options

In order to evaluate how to finance the project, Carollo examined three different financing rates and terms (durations) to evaluate the potential ranges of financing options. Table 14 and Figure 15 illustrate the three scenarios and the results for the 20-year net present value. Based on these rates and terms, the variance in the 20-year net present value results is negligible based on all the assumptions used. Assuming L/E can manage the monthly payments, the financing terms should be less than 7 years duration and preferably the shorter the more advantageous.

Table 14 Net Present Value with Varying Financing Options

Interest Rate	Loan Terms (duration)	20-Year Net Present Value
Baseline (L/EWWTP-financed)	0	$17,973,300
3%	3-year	$18,179,400
5.5%	7-year	$17,621,300
8%	10-year	$16,486,600

Notes:
(1) RIN value = $2.50 (baseline condition).

Figure 15 shows the annual cumulative cash flow projections based on the financing scenarios listed in Table 14. This figure illustrates using a financing option to procure the design and construction services for the pipeline injection alternative appear to be most prudent and generate positive cash flow for L/EWWTP before the RINs credits expire.

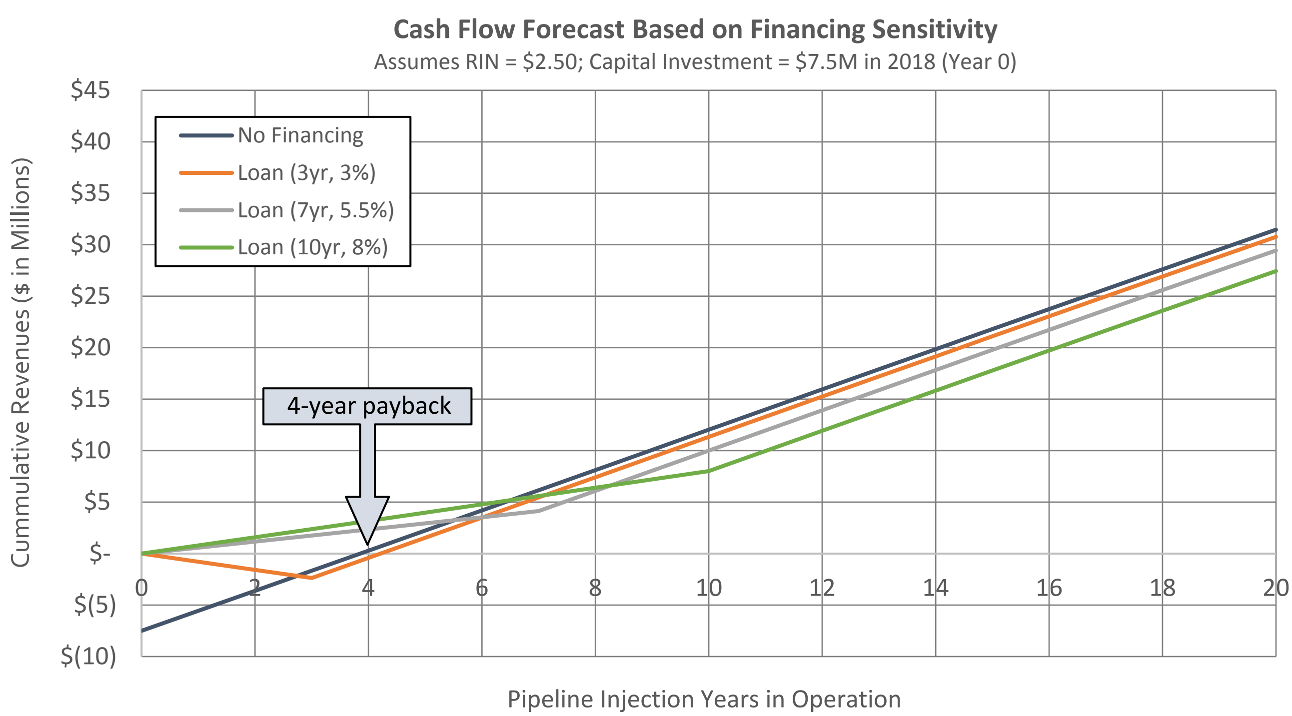

Figure 15 Financing Sensitivity

For 7- and 10-year loans, the L/EWWTP would have a positive cash flow starting in year one and continuing throughout the project. The 3-year loan payments would result in a negative cash flow through the third year of operation and by year five, the project would reach a net positive payback.

1.9.2 Exit Strategies

As part of this evaluation, the team identified several revenue generating exit strategies that may be used in the event that the RFS Program is significantly modified beyond 2022, such that RINs no longer hold sufficient value to continue with pipeline injection. While this is not anticipated to be the case based on conversations with both RIN brokers and obligated parties (e.g., oil producers), it is prudent to identify these alternatives at the project outset.

One possible off-ramp from pipeline injection may be to install a CNG fueling station either on-site or adjacent to the L/EWWTP in the future. If CNG vehicles become more common and CNG fuel prices increase, the L/EWWTP may be able to realize a revenue stream from conditioning the gas and selling it directly as vehicle fuel. The L/EWWTP location adjacent to Santa Fe Road makes this a viable future option. The capital cost for this exit strategy is anticipated to be in the range of $1 to $2 million, with a potential revenue stream of $100,000 per year. This revenue stream is highly dependent on CNG demand from the fueling station.

Another possible off-ramp is to return to cogeneration to produce electricity. With the gas conditioning system already installed, the L/EWWTP has the option to re-start the existing engines or purchase new engines. With the proper gas conditioning, it is anticipated that the engines would have significantly lower maintenance as compared to plant staff's previous experience. The capital cost for installation of two new engines is anticipated to be in the range of $2 to $3 million, with a potential revenue stream (or electricity cost offset) of $500,000 per year.

1.10 Implementation Plan

In order to take advantage of the legally mandated RIN quotas through 2022, it is in the L/EWWTP's interest to get the project on track as quickly as possible (i.e., reduce the time to market). As part of this effort, L/EWWTP staff and Carollo developed an implementation plan to forecast required activities and lead times. Figure 15 shows a general schedule, with the major required activities and coordination items spelled out.

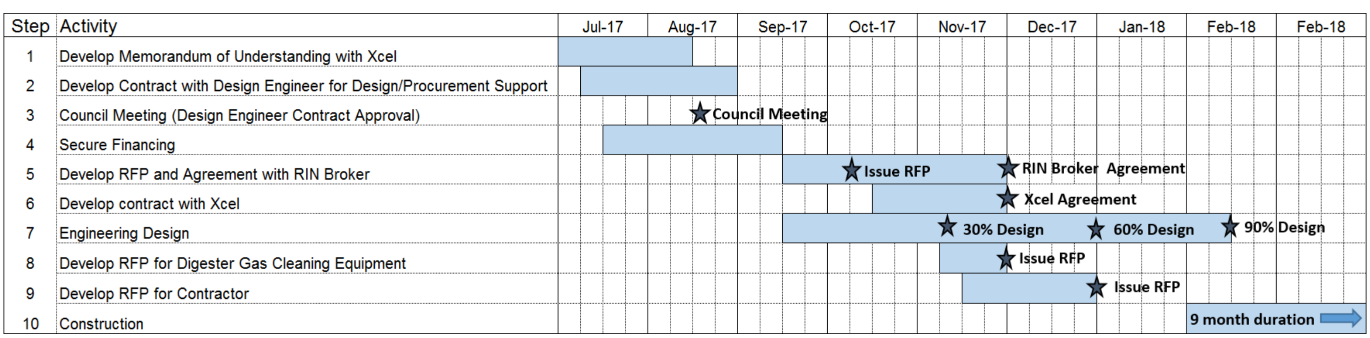

Figure 16 Implementation Schedule

One critical activity that has been identified is coordination with Xcel Energy. The development and acceptance by all parties of an Interconnect Agreement between L/EWWTP and Xcel will be a critical project milestone. As such, members of the L/EWWTP staff, Carollo, and Xcel Energy met to discuss the required gas quality, Xcel required monitoring equipment, and other preconditions for an agreement. The L/EWWTP and Xcel will work together to agree on a Memorandum of Understanding so the L/EWWTP has a commitment from Xcel while working on the other coordination items identified in the implementation schedule.

Additional steps shown in the schedule include:

- Securing financing,
- Developing a request for proposals to obtain a RIN broker,
- Developing a contract with the design engineer,
- Performing the engineering design,
- Procuring the biogas conditioning equipment,
- Construction, and
- RIN certification.

It is the goal of the L/EWWTP to have all of the above steps completed by the end of 2018 such that RIN credits may begin to be realized in 2019.

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Appendix A

XCEL RNG QUALITY REQUIREMENTS

Xcel Energy
Renewable Natural Gas Quality Specifications

Colorado

Public Service Company of Colorado Gas Tariff INERT BLENDED SYSTEM		
Constituents/Properties	**Limit**	**Units**
Higher Heating Value	**965 - 1100**	Btu/scf
Wobbe (based on HHV)	**1185 - 1285**	
Carbon Dioxide (mol %)	**3.0**	mol %
Oxygen	**2.0**	mol %
Total Inerts	**14.3**	mol %
Hydrogen Sulfide H_2S **Total Sulfur**	**0.25 (4)** **5.0 (85)**	gr/Cscf (ppmv)
Hydrocarbon Dew Point, Cricondentherm	**15**	°F
Water Vapor Content	**3**	lb/ MMscf
Dust, dirt, gum and other solids	**Free of**	
Water & hydrocarbons in liquid form	**Free of**	
Temperature	**32 – 110**	°F

Hazardous Substances/ Objectionable Matter*	DRAFT (Based on California Rule 30)	
Constituents/Properties	**Proposed Limit**	**Units**
Volatile Organic Compounds (VOCs)		
Siloxanes (Total Si)	0.1	mg/m^3
Vinyl Chloride	1170	ppbv
Chorinated/Halogenated Hydrocarbons: Chlorobenzene, trichlorofluoromethane, etc.	100	ppbv
Organic Sulfur: Carbonyl sulfide, Carbon Disulfide, Dimethyl Sulfide, etc.	1	ppmv
BTEX and other aromatics	50	ppmv
Hexanes+ Alkanes	100	ppmv
Formaldehyde/Aldehydes and Ketones	100	ppbv
Other VOCs	100	ppbv
Semi-Volatile Organic Compounds	100	ppbv
Polycyclic Aromatic Hydrocarbons	100	ppbv
Volatile Fatty Acids	10	ppbv
Polychlorinated Biphenyls	0.1	ppbv
Pesticides	1	ppbv
Products	1	ppbv
Inorganic Compounds/Metals		
Mercury	0.01	$\mu g/m^3$
Hydrogen	0.1	mol %
Arsenic, Zinc, Antimony	0.01	$\mu g/m^3$
Ammonia	10	ppmv
Biologicals	0.2	micron

*Constituents may vary with type of biogas

Appendix B

CAPITAL COST ESTIMATES

Engineers...Working Wonders With Water®

VEHICLE FUELING

Project: **Biogas Use Applications**
Client: **Littleton-Englewood WWTP**
Location: **Englewood, CO**

Date : **August 2017**
By : **TMD**
Reviewed: **BJL**

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	550	CY	$9.40	$5,167	
	Total					**$5,167**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	95	CY	$339	$32,214	
	Total					**$32,214**
	Division 11 - Equipment					
11000	CNG Storage	1	EA	$750,000	$750,000	
11000	BioCNG Thermal Oxidizing Flare	1	EA	$341,900	$341,900	
11000	BioCNG 400 DP Winterization	1	EA	$266,000	$266,000	
11000	BioCNG 400 DP	1	EA	$2,041,491	$2,041,491	
11000	BioCNG Control Panel	1	EA	$45,000	$45,000	
	Total					**$3,444,391**
	Division 15 - Mechanical					
15000	Pipe Tunnelling under River	120	LF	$800	$96,000	
15267	4" Sdr 11 Hdpe Pipe In Open Trench	17,500	LF	$54	$940,625	
15286	6" Sch 40S Buttwelded 316L Sst Pipe In A Bldg To 12' Ht.	200	LF	$116	$23,273	
	Total					**$1,059,898**
	Division 16 - Electrical					
16000	EI&C Allowance	15%	of Div 11	$3,444,391	$516,659	
	Total					**$516,659**
	Division 17 - Instrumentation and Controls					
17000	Contingency	20%	EA	$5,058,328	$1,011,666	
17000	General Contractor Overhead, Profit, and Risk	15%	EA	$6,069,994	$910,499	
17000	Escalation to Mid-Point (2018)	5%	EA	$6,980,493	$349,025	
	Total Construction Cost					$7,324,351
17000	Engineering, Legal, and Administrative Fees	15%	EA	$7,324,351	$1,098,653	
	Total					**$8,423,003**
	Grand Total					**$8,423,003**

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PIPELINE INJECTION

Project: Biogas Use Applications
Client: Littleton-Englewood WWTP
Location: Englewood, CO

Date : August 2017
By : TMD
Reviewed: BJL

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	550	CY	$9.40	$5,167	
	Total					**$5,167**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	95	CY	$339	$32,214	
	Total					**$32,214**
	Division 11 - Equipment					
11000	BioCNG 400 DP	1	EA	$2,041,491	$2,041,491	
11000	BioCNG Control Panel	1	EA	$45,000	$45,000	
11000	BioCNG 400 DP Winterization	1	EA	$266,000	$266,000	
11000	BioCNG Thermal Oxidizing Flare	1	EA	$341,900	$341,900	
11000	Xcel Monitoring Equipment	1	EA	$1,050,000	$1,050,000	
	Total					**$3,744,391**
	Division 15 - Mechanical					
15267	4" Sdr 11 Hdpe Pipe In Open Trench	2,500	LF	$54	$134,375	
15286	6" Sch 40S Buttwelded 316L Sst Pipe In A Bldg To 12' Ht.	200	LF	$116	$23,273	
	Total					**$157,648**
	Division 16 - Electrical					
16000	EI&C Allowance	15%	% Div 11	$3,744,391	$561,658.64	
	Total					**$561,659**
	Contingency	20%	EA	$4,501,078	$900,216	
	General Contractor Overhead, Profit, and Risk	15%	EA	$5,401,294	$810,194	
	Escalation to Mid-Point (2018)	5%	EA	$6,211,488	$310,574	
	Total Estimated Construction Cost					**$6,522,063**
	Engineering, Legal, and Administrative Fees	15%	EA	$6,522,063	$978,309	
	Total Project Cost					**$7,500,372**