Financially feasible anaerobic digesters: A proposal for Clean Fuel Partners

Engineering 601: Interdisciplinary Design for Energy and Sustainability

Water Quality & Nutrient Management—Fall 2017

EXECUTIVE SUMMARY

Clean Fuel Partners (CFP) owns several anaerobic digesters and currently uses them to produce electricity to be sold to a local utility. However, this arrangement is only profitable because the two companies have a power purchase agreement (PPA) with one another. Once the PPA is up, Clean Fuel Partners needs to find a different use for the biogas produced by their digesters, as well as for the fiber produced as a byproduct in the process. The fiber especially needs to be transported outside of the Yahara watershed as to not pollute the watershed with excess nutrients.

Our team has come up with the option of scrubbing the biogas of impurities, and then injecting it into a natural gas pipeline to generate revenue from Renewable Identification Numbers (RINs) through companies in California. RINs have a set value based on the material made to produce the natural gas. Based on current feed into digesters at Clean Fuel Partners, there would be a mix of D3 and D5 RINs. However, in order to increase the profit margins, we have decided to pursue solely D3 RINs, as they are more valuable, and are made almost entirely from cellulosic matter (manure). Based on current gas production this would total between $6,200-$9,300 a day for two running digesters.

The process for producing pipeline ready gas requires the purchase and implementation of several new technologies including a gas scrubber, a compressor, tube trailers, and storage tanks. A gas scrubber is required to clean the biogas of impurities, until it is 96.7% methane. Amine scrubbers are the most efficient technology for the job, but have a high initial investment of approximately $2.4 million. Methane must be compressed for transport; thus, a compressor is needed on site, which totals $100,000. Tube trailers are used to transport natural gas to the injection point where it will be added to the pipeline, and it would cost between $500 and $1,000

for a third party to transport the gas every eight days. As a fall back should anything happen to the compressor, or to the tube trailers, we also recommend purchasing portable storage tanks for the gas, which would be a $4,000 investment.

The fiber byproduct of the digesters is currently not profitable for Clean Fuel Partners. In order to make it a more valuable part of the process, we have decided to pelletize it. Pelletizing fiber removes a large amount of the moisture from it, reducing transportation costs. The fiber pellets can then serve as a marketable product such as biofertilizer for farms or gardens. Similarly, with the natural gas process, there are several new technologies that need to be put in place in order to pelletize the fiber.

The first new technology that would need to be put in place for the fiber pelletizing process is a rotary drum dryer, in order to remove the vast majority of the moisture from the fiber product. This would have an upfront cost of $480,000, and an operational cost of $846 a day. After the fiber has been dried, it needs to be pelletized into the final product shape. The pelletizer costs $300,000, and has a daily operational cost of $300. Assuming daily earnings between $2,500 and $8,500, it would take approximately half of a year to pay for the new fiber machinery.

The design that we are suggesting has a large upfront cost, but the payback period for the entire initial investment based on RIN prices and fiber prices would only be one to two years. Also, the technologies for pipeline injection are being used by other natural gas producers, so it is proven to work. Farms that produce biogas also pelletize their fiber using a similar process to our proposed option, so this is also a viable option.

Future considerations include implementing a fourth digester to increase gas production. Another option would be looking into a source for more manure, so that more cellulosic methane can be produced. This would greatly increase revenue but would involve the costs associated with transporting more manure, as well as where to get the manure from.

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1.1. Project Scope

1.1.1. Problem Statement

The biogas produced from the Clean Fuel digesters is used to produce electricity and then sold to utility companies. Currently, there is a Power Purchase Agreement (PPA) set up through a local utility, which is paying Clean Fuel a subsidized rate for their electricity. Unfortunately, the agreement will expire in 2020, and the price that Clean Fuel receives for their electricity will fall $0.07/kWh. There is no feasible way for Clean Fuel Partners to lower the production cost of electricity to allow for profitable production with such a decline in price. Therefore, the company will undergo serious economic stress if another use for the biogas is not found. Any alternative biogas use should be economically feasible and cause minimal environmental impact. Additionally, alternative revenue streams and applications for the solid fiber byproduct should be explored. The current method of distributing it to farms outside of the Yahara watershed does not seem to be economically viable.

1.1.2. Clean Fuel Partners Needs

Clean Fuel Partners needs a new option for what to do with the biogas that is being produced by their anaerobic digesters, because of the termination of the power purchase agreement. This means that they also need our team to come up with options for what to do with any of their current machinery that will be obsolete under the new plan. The Dane County local government is in need of options for reducing the amount of phosphorus that is being leaked into the Yahara Watershed. This is a problem that they tasked Clean Fuel Partners with, and has thus been passed on to us.

1.1.3. Clean Fuel Partners Limitations

As they are now, Clean Fuel Partners has several limitations that need to be considered when working on this design. Each of their digesters has a maximum output flow of 250 scfm. This limits the amount of gas that can be produced each day. Also, the amount of manure they get varies from day to day, by values greater than 10,000 gallons. This would make it difficult to have an adjusted feed stream to pursue D3 RINs. The manure flow is not something that Clean Fuel Partners can control, it is entirely dependent on the farms. There are no other farms close enough to easily install a pipe, they will need to search farther out if they want to increase their manure flow. Also, the digesters are located on top of the digester, so the fiber pellets cannot be sold in a local area, they must be transported.

1.2. Background

1.2.1. Gas Production

Anaerobic digestion is a process by which sugars in organic compounds are broken down into methane and carbon dioxide through a series of chemical reactions. The first reaction is hydrolysis, which is the bacterial breakdown of insoluble polymers into soluble compounds. Then, acidogenesis occurs, which is a process whereby acidogenic bacteria breakdown the soluble sugars and amino acids into simple compounds such as hydrogen, ammonia, carbon dioxide, and other simple organic compounds. Third in the process is acetogenesis. Acetogenesis is a process where the organic compounds from the second step are broken down further into acetic acid, and more hydrogen, ammonia, and carbon dioxide. The final step in anaerobic digestion is methanogenesis, which occurs when the acetic acid, hydrogen, ammonia, and carbon dioxide are converted into methane.

The overall reaction is displayed in Reaction (1):

$$(1)\quad C_6H_{12}O_6 \rightarrow 3CO_2 + 3CH_4$$

The final product, a mixture of methane, carbon dioxide, and other waste gases, is referred to as biogas.

Two of the three anaerobic digesters at Clean Fuel Partners are currently being utilized to make biogas. Cow manure from three local farms as well as substrates from several local restaurants are being used as fuel for the digesters. Each digester has a maximum capacity output of 250 scfm, and the biogas that is produced has an approximate composition of 60% methane, 40% CO_2, with trace amounts of other gases including 2,000 ppm O_2, and 200 ppm hydrogen sulfide. The gas is run through a scrubber in order to remove the toxic hydrogen sulfide. Generators are then used to combust the biogas, which produces electricity. Clean Fuel Partner's power purchase agreement with the utility means that they sell the electricity to the utility, and then they buy back electricity to run their plant operations at a subsidized rate.

1.2.2. Fiber Output Surplus

Cow manure is brought in from nearby three farms through an underground piping system into the plant. When the manure and substrates undergo the process to produce gas, fiber is made as a byproduct. Once the fiber is dried, it is stored in the solids building to await pick up. Currently, a farm east of Madison picks up approximately 1.5 truckloads of the fiber per day. However, this farm has two digesters located on their property, and a drying system for wet fiber is currently under construction. Once they start producing their own dry fiber, they will eliminate business with Clean Fuel Partners.

The fiber plays an important role in capturing high levels of phosphorus from the digestate, allowing Clean Fuel Partners to relocate it. The phosphorus needs to be moved outside of the Yahara watershed, otherwise damaging levels will continue to infiltrate neighboring bodies of water. If the fiber is used nearby the Yahara watershed, the runoff would pull the phosphorus into the waterways. If the too much phosphorus is released into waterways, it would instigate an algae bloom. The algae can produce toxins and decrease the water quality.

Clean Fuel Partners is already over-encumbered with the levels of fiber they produce, and it may increase in the future. Currently, they are not making any money in the process of getting rid of it, and in some cases it is costing them money. It is important that we critically analyze possible solutions for the currently-burdening fiber byproduct.

1.2.3. Decision Matrix

Upon brainstorming solutions for biogas, our group went through a process of elimination and decided on three viable options: a natural gas injection point, bio-compressed natural gas, and diesel.

The production of diesel requires additional equipment designed by Ag Waste Solutions, which are the Solids Recovery Module, Gas Production Module, Gas Conditioning Module, and Liquid Fuel Module. To produce diesel, the manure enters the Solids Recovery Module and removes the solids from the waste, then continues to the Gas Production Module. Here, the solids decompose and produce a biosynthetic gas and a mineral ash byproduct. The Gas Conditioning Module cleans the biosynthetic gas and removes sulfur and other contaminants. The biosynthetic gas is converted into diesel through the Liquid Fuel Module [1]. The return on the capital investment takes around 3 years and operating costs of approximately $1.50 per gallon of diesel, which is based on producing 4,200 gal of diesel per day. To produce 1 gallon of diesel, it requires 55 to 135 lbs of manure [2]. Based on Clean Fuel Partners receiving approximately 90,000 gallons of manure per day [3], 2,200-5,500 gallons of diesel could potentially be produced per day. With an average of 3,800 gallons of diesel produced per day, roughly $5,800 would be spent on operating costs per day (shown in Appendix: Calculation A, B, C).

Another option explored was bio compressed natural gas (CNG). The process would include a scrubber and compressor. This equipment is already need for the injection point option. The most significant difference is where the gas will go after it is produced. For the compressed natural gas, it would be fuel for CNG vehicles.

The most significant setback in this both of these option is the need for people to come to the plant to retrieve either the diesel or compressed natural gas. Most individuals tend to fuel their vehicles at the most convenient location. The location of Clean Fuel Partners may not be the most convenient for people to stop and refuel their vehicles. The fuel could be brought to location with a higher density of people, but that would require equipment to be in place to hold the fuel and an operating system to facilitate the transaction.

					Costs			Sustainability				**Total**
	Revenue	Ease of Implementation	Safety	Regulatory Barriers	Initail Capital Investments	Operation/Maintenance	Transportation	Economy (Payback)	Environmental	Society		
Weight (1-5)	5	2	3	3	2	4	4	4	3	1		
Gas Options												
Injection Point	10	7	7	9	5	8	9	10	4	7		**249**
BioCNG	7	4	6	5	2	5	7	6	8	5		**181**
Diesel	6	5	8	6	4	6	8	8	8	7		**209**

Figure 1a. Decision Matrix for Natural Gas Injection Point, Bio-Compressed Natural Gas, and Diesel.

Based on the results from the decision matrix (Figure 1a.), the injection point at the landfill appears to be the most feasible option. The primary focus of the outcome of this project is to find a financially stable option with minimal environmental impacts.

1.2.4. Sustainability Goals

In regards to sustainability concerns, CFP provides numerous benefits that promote environmental sustainability. On average, CFP removes 70,000 lbs of phosphorus per year from the Yahara watershed. Removing phosphorus from the Yahara watershed protects it from phosphorus runoff from fertilizer and manure, in turn algal blooms in Lakes Mendota, Monona, Waubesa and Kegonsa. These benefits enhance water quality, maintain soil integrity, regenerate phosphorus supplies, and dampen complications for water treatment facilities down the line. If CFP were unable to continue operating due to lack of viable alternatives for their produced biogas, environmental sustainability in the Yahara Watershed and Dane county would take a hit. In order to maintain environmental sustainability, it is our goal in exploring alternatives to end at a set of solutions that are also *economically* sustainable, so as to provide the labor, time and investments required to keep CFP operating in years to come. Lastly, and perhaps to a lesser extent in our scenario, it is important to take into consideration social sustainability as well. Unlike other renewable energy sources pegged to be visually obtrusive like wind energy or land demanding like solar energy, energy from anaerobic digestion has numerous advantages. CFP is located a significant distance away from urban areas, has a minimal land area requirement, and no competition pressures from other anaerobic digestion/waste-to-energy companies. Many Dane county residents are relatively unaware of CFP and energy derived from anaerobic digestion, and many of those who are aware of the process are in favor of it, due to the environmental benefits associated with operation. Bearing all components of sustainability in mind, we have designed a modified process in hopes of acknowledging all three and keeping CFP in operation.

2. Design Description

2.1. Overview

2.1.1. *Process* vs. *Product*

Our project was somewhat unique in that we were designing a process rather than a product. This means that we had to have in depth knowledge of the entire anaerobic digestion process from partner companies, to input and output streams, to carbon credits, to fiber option feasibility. Because of this, our project involved a lot of contact from outside companies in the Dane County area, as well as multiple employees within Clean Fuel Partners. In all, our project is theoretical until the company decides whether or not to implement it, and we are not presenting them with some sort of new technology to solve all of their problems. This has its benefits and drawbacks. It is beneficial in that the company does not have to put their full trust in a completely new product, they can use technology that is already on the market, which is cheaper to implement, and widely used. A drawback is that their problem persists until they can fully implement the process, which is lengthy and expensive.

2.1.2. Natural Gas Injection Summary

Utilizing the Dane County landfill injection point requires the implementation of several new technologies. Because the gas produced from anaerobic digestion has a high CO_2 content as well as a high sulfur content, these components need to be scrubbed out using a gas scrubber. Also, in order to transport fuel, it needs to be compressed to 3,000 psi to be loaded into tube trailers. A third party will then be contracted to transport the fuel to the injection point, where it needs to be compressed to 700 psi and injected into the pipeline.

2.2. Design Description (In-Depth)

2.2.1. RFS/LCFS Background

Prior to explaining the mechanisms for converting Clean Fuel Partners' biogas into natural gas, it is first valuable to recognize the primary financial incentive in doing so. Fuel that is derived from clean sources is sometimes eligible for carbon credit under an offshoot of a federal program called the Renewable Fuel Standard (RFS) program. The RFS program was created under the Energy Policy Act of 2005 (EPAct) which amended the Clean Air Act that first made an appearance in 1963. It is a national policy that requires a certain percentage of renewable fuel to replace or reduce the quantity of petroleum based fuels used elsewhere. The actual currency generated by the renewable fuel producer is referred to as a Renewable Identification Number, or RIN for short. One way a RIN can be conceptualized is as one ethanol gallon worth of energy, or 77,000 BTU. They are the raw credits used to demonstrate compliance with the RFS, and they can be purchased on the market or attached to a batch of fuel. As mentioned, "assigned" RINs are RINs that are directly associated with a batch of clean fuel, whereas "separated" RINs are RINs that were formerly attached to a batch of fuel, but are only purchasable once detached from that batch. The first year a RIN is generated is commonly referred to as its "vintage year", while the last stretch of a RINs life is when it is purchased and deemed a "retired" RIN. [5] A descriptive flowchart of the RIN lifecycle can be seen in (Figure 2a).

RIN Lifecycle

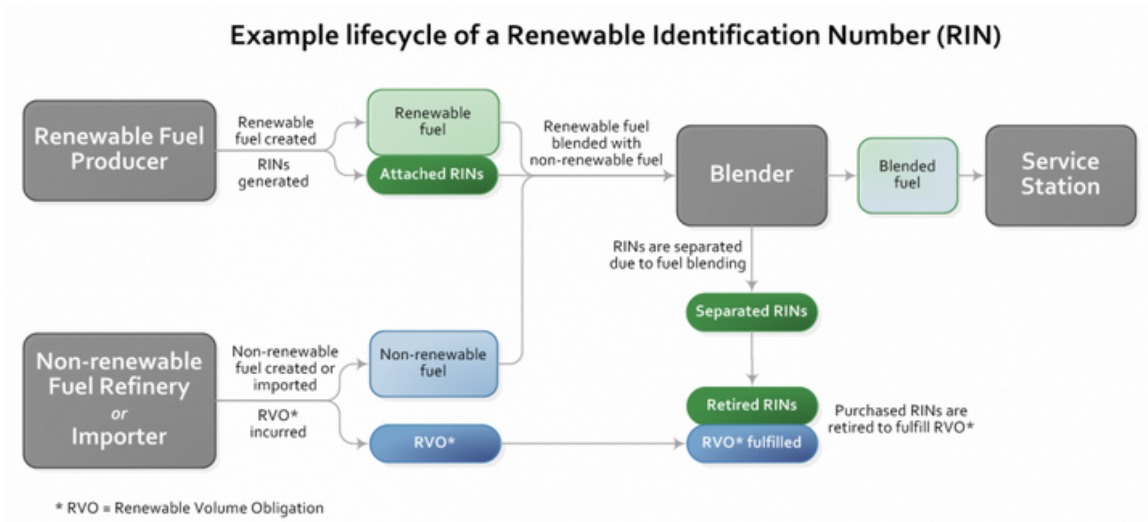

Figure 2a. RIN Lifecycle [5]

Although there are numerous classifications of RINs, there are only 2 specific classifications that Clean Fuel Partners is specifically eligible for. D3 RINs are RINs are classified as cellulosic biofuels, and they must be at least 75% cellulosic while accounting for a 60% lifecycle greenhouse gas (GHG) reduction compared to the petroleum baseline, a goal that can be met with ease from Clean Fuel Partners' intake of cow manure from Maier's, Ripp's and Endres farms. The other available credit would come from a D5 RIN, classified as advanced biofuels and required to account for a 50% lifecycle GHG reduction compared to the petroleum baseline. Furthermore, the D3 RIN value is substantially great than that of the D5 RIN, fluctuating from $2.50-$3.00/RIN compared with roughly $1.00/RIN, respectively [4]. RIN valuation and biofuel feed ratio calculations will be visited more in depth in the following section. One of the reasons that D3 RINs are more valuable than D5 RINs is simply that there are fewer of them, and thus an elevated demand for D3. Thus, congressional goals for RINs generated from renewable fuels increase sharply for D3 RINs, reaching a goal of 36 billion gallons of renewable fuel from D3 by 2022, as can be seen in (Figure 2b).

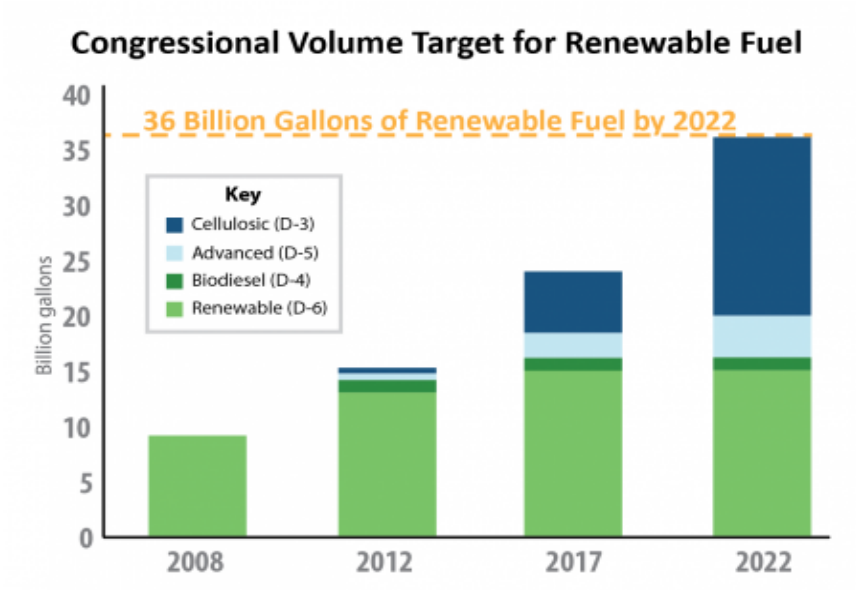

Figure 2b. Congressional Volume Target for Renewable Fuel [5]

Additionally, in terms of initiating the transition to the RIN system, there is incentive to prioritize D3 RINs over D5 as they tend to clear through the early stages of the registration process more rapidly. On average, the clearing of a complete registration application takes 4 to 6 months for various RIN types, while this can be as low as 60 days for D3 RINs alone.

Moreover, there are a number of considerations for Clean Fuel Partners to bear in mind in transitioning to the RIN system. For instance, although RINs are tracked under an EPA Moderated Transaction System (EMTS), a database of records for all transactions involving RINs, a third party is typically hired to begin the transition process and sometimes kept on to continue facilitating the transaction process. General fees, initially, float around $10 - $20,000 while an ongoing contract with an accreditation company can require as much as 25% commission. [4] Also, there is a lesser known market reality associated with D3 RINs; in order to make RINs marketable and purchasable, they need to undergo a voluntary quality assurance

(VQA) program. Within this VQA program, a third party is paid to verify the RINs. If they pass the criteria for cellulosic requirements, compliance requirements and others, they then receive a special flag as “Q-RIN”. Unfortunately, this special classification is the only way to make RINs marketable and costs approximately $20-$40,000 per year. [4]

Lastly, it is important to acknowledge another carbon credit system that although not pursued, should remain identified for future thoughts. Contrary to federal RINs, the California Low Carbon Fuel Standard (LCFS) is a state program under California Assembly Bill AB 32: California Global Warming Solutions Act of 2006. This act calls for a variety of requirements like a cap of GHG emissions by 2020, mandatory emissions reporting, identification of early action measures, etc. The LCFS was approved in 2009, and implemented January 1st, 2011, and encourages the use of low carbon fuels specifically in California, in effort to stray from a reliance on roughly 96% petroleum-based fuels [6]. One of the difficulties of pursuing this program over the RIN program is that it is expressed in carbon intensity (CI), or GHG associated with emission from producing and consuming a fuel measured in gCO_2e/MJ. This is more difficult to measure, especially when the clean fuel produced would be from integrated sources. Substrates would elevate Clean Fuel Partner’s CI and thus offset the CI saved from only using cow manure as an input.

Insofar as accreditation form LCFS credits, there are complications with where a batch of gas ends its life. Although biogas is eligible for credit, under the LCFS requirements, it needs to be verified that the fuel was used for transportation, and furthermore for transportation *in* California. Hence, more costs would be incurred by Clean Fuel Partners to verify this criterion. From a market standpoint, although LCFS credits can be quite valuable, the market for these credits has been somewhat cornered, in a sense, by renewable fuel producers in California [4].

Although the market is competitive and difficult to measure, using bio-methane may prove to worthwhile sometime down the line, and thus we encourage Clean Fuel Partner's to keep the alternative in mind.

In summary of the various options, not only is it more advantageous to pursue the federal RIN carbon credit program, but it is more beneficial to specifically pursue a revenue stream from D3 RINs. It will be the quickest to initiate, easier to handle ongoing transactions, and equally, if not more valuable at a price of $2-3/RIN. Incorporating D5 RINs will complicate the process, as a "converted fraction" then needs to be taken into account, in which the cellulosic vs. non-cellulosic content of the renewable fuel source must be analyzed before successfully submitting a complete registration application.

As aforementioned, to qualify for the D3 RINs, 75% of the natural gas produced has to come from cellulosic sources (manure). Based on manure fed, manure density, and gas production capabilities of manure, it was determined that approximately 90,000 scf of gas per day is produced from the manure alone from one digester. The calculations are shown in Equation (1):

$$\frac{45{,}000\ gallons\ fed}{digester \cdot day} * \frac{8\ lb}{gallon} * \frac{0.065\ solids}{manure} * \frac{0.454592\ kg}{lb} * \frac{0.24 scf\ gas}{kg\ manure} * \frac{35.314\ m^3}{scf} \quad (1)$$

Using values: 45,000 gallons fed/day/digester of manure for Clean Fuel Partners. 8 lb/gallon density of liquid manure, (Missouri State University). 6.5% solids for Clean Fuel Partners. 1 kg of manure produces 0.24 scf of gas, (Missouri State University).

Using the 90,000 scfd of natural gas and comparing it to the 228,000 scfd/digester that is currently being produced, it was determined that 39.4% of the gas being produced currently is from manure. To increase gas production, we supplemented the feed with substrates, because they have a higher gas production capability than manure, and Clean Fuel Partners is payed to take them. By adding in substrates to produce 25% of the gas, it was determined that Clean Fuel Partners could make 120,000 scfd of gas/digester, while still qualifying for D3 RINs. Another possibility would be increasing the amount of manure fed to each digester, which would involve outsourcing for more manure, but would increase the revenue.

Using the adjusted input stream output of 120,000 scfd, and the price of RINs ranging from \$2.00 to \$3.00, it was determined that the revenue from the two digesters currently running would range from \$6,200 to \$7,800 per day. This is only slightly more profitable than the current electricity production. In order to increase revenue, we recommend pursuing a larger amount of manure to feed to the digesters. The gas output adjusted for 75% coming from manure produces only about half of the limit of gas production for each digester. If the gas production was increased to the maximum 228,000 scfd for each digester, it would require 114,000 gallons of manure for each digester, and would generate revenue in a range of \$11,800 To \$17,800 per day for two digesters.

An alternative option to mixing the substrates and manure would be using the third digester that is not currently being utilized to run strait D5 RINs, using the only substrates, and running the other two with pure manure. This would be an additional revenue, but would bring up complications of adding in more pipelines in order to prevent the two gas streams from mixing. This way Clean Fuel Partners could sell natural gas for both D3 and D5 RINs without worrying about the input streams. Or, they could mix the two gas streams after they are produced, so they had a composition of three parts straight manure based, and one part substrates based, in order to still pursue D3 RINs. Due to the complications associated with this method, we did not look into it further, but felt that it was a viable option to look at in the future.

2.2.2. ANR Pipeline Background

The pipeline in which the generated natural gas will physically be injected into is the American Natural Resources (ANR) pipeline (Figure 2c.), one of the largest interstate natural gas pipelines in the U.S. Through its approximately 10,600 miles of pipeline, ANR delivers more than 1 trillion cubic feet of natural gas annually, with a peak-day delivery capacity of more than 6 billion cubic feet (Bcf) [7]. It contains two large legs that deliver natural gas from Texas and Louisiana to the Great Lakes area. As aforementioned, the natural gas needs to be treated to 96.7% CH_4 and an operating pressure of approximately 700 PSI after transport and decompression. Luckily, this pipeline conveniently sits under the site of the Dane county landfill, located 24.7 miles from Clean Fuel Partners, assuming the shortest route.

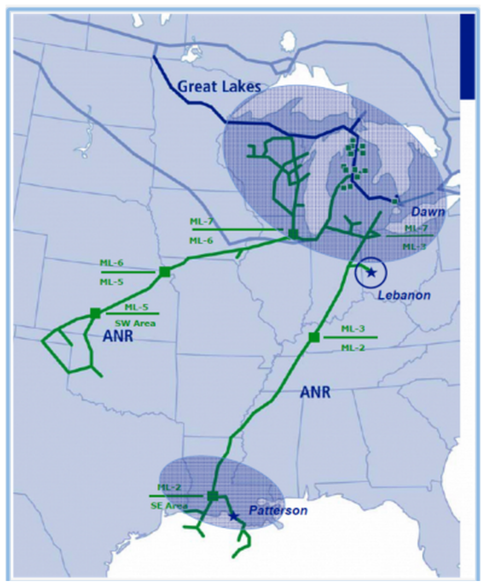

Figure 2c. American Natural Resources (ANR) Pipeline.

2.2.3. Dane County Landfill Background

The Dane County landfill, located directly northeast of the highway I-90/Beltline intersection, opened in 1985 and is currently the only active landfill in Dane county. Unfortunately, the landfill only has enough space to operate for another 6-7 years before needing to relocate. Additionally, they are under a similar PPA with MG&E such that they are subsidized to provide MG&E with clean electricity. Contrary to Clean Fuel Partners, they have 7800 kWh generators, 52 gas collection wells, and produce gas that is ~55% CH_4 [8]. Although the landfill made $3.5 million in electricity revenue in 2016, their PPA is up in 2019 and thus they face a similar dilemma as Clean Fuel Partners. Luckily for CFP, after the landfills PPA is up or they relocate, their gas production from waste will continue for years to come and thus the site will remain undisturbed and in compliance with regulatory standards. CFP will be permitted to inject biomethane into the ANR pipeline under an agreed upon fee to the county of Dane. Before injection and transportation, however, the biogas must be treated at the CFP facility and there are variety of considerations and costs to consider in evaluating this option.

2.2.4. Biogas Treatment

Currently, the biogas being produced by the digester has a range of compositions, with an average of approximately 60% methane, 40% carbon dioxide, and 200 ppm hydrogen sulfide. As the gas is to be put into a natural gas pipeline, it needs to be purified to 96.7% methane, with a balance of carbon monoxide. As much of the sulfur as possible must be removed from the biogas, because it is corrosive and toxic to humans. In order to achieve pipeline level purity, the gas must be run through a scrubber designed to react with carbon dioxide and hydrogen sulfide, without removing any methane from the stream. There are multiple scrubber technologies that are commonly implemented in industry, and each option was evaluated to determine what the most economical scrubber would be for Clean Fuel Partner's digesters.

The first scrubber option that was researched was a water scrubber. Water scrubbers use a non-regenerative adsorption process, and can be used with a range of 0-300 ppm of hydrogen sulfide [13]. Also, there is only a small amount of methane lost (<2%) [12] using this technology. While this technology has many advantages, they are somewhat offset by the issues associated with water scrubbing. When using water, the water cannot be reused, and the saturated solution must be disposed of in some way. Also with water scrubbers there is very little ability for variation in the amount and composition of the feed [12], which would not be ideal for an anaerobic digester, where the feed is susceptible to change. Clean Fuel Partners is also looking at putting in another digester, which would significantly increase the gas flow. Water as a solvent increases the chances of bacterial growth, the technology also involves large capital and operation costs. It is due to economic considerations as well as compatibility issues that the water scrubbers were determined to be non-ideal for this site.

Another option that was looked into was implementing membrane technology in order to purify the biogas. Membranes are capable of removing both carbon monoxide and hydrogen sulfide, and have low capital and maintenance costs [13]. However, the use of membranes requires multiple purification steps [12], as they cannot create a highly pure product after only one membrane. Also, there are more significant losses of methane from this method, due to the need for multiple steps. The loss of methane, and the complication associated with adding multiple steps to an already existing infrastructure makes this technology non-ideal for our situation.

The final scrubber option, and the most viable, is amine scrubbing technologies. Amine scrubbing is a regenerative process wherein biogas is bubbled through a liquid amine solvent that reacts with the hydrogen sulfide and the carbon dioxide, while leaving methane unaffected [13]. The amine scrubbers have a high removal percentage for carbon dioxide and hydrogen sulfide, with minimal methane losses (<0.1%) [13]. It also has extremely low operation costs, because the amines can be used multiple times, and it has more flexibility when it comes to input gas flows. Price is the only main downside to this technology, as it has incredibly high upfront cost, however we feel that the many upsides of this type of scrubber greatly outweigh the initial cost.

Amine scrubbers utilize a reversible exothermic reaction between carbon dioxide and amines such as monoethanolamine (MEA), diethanolamine (DEA), and methyldiethanolamine (MDEA). The biogas is bubbled up through an aqueous alkanolamine solution, where the amines will react with carbon monoxide and hydrogen sulfide, while allowing methane to pass through. Following the adsorption step, the carbon dioxide saturated amines are sent to a stripping column. Adding heat removes the CO_2 from solution, thus regenerating the amine for continued use in gas scrubbing. Figure (2d) below shows the general makeup of an amine scrubber.

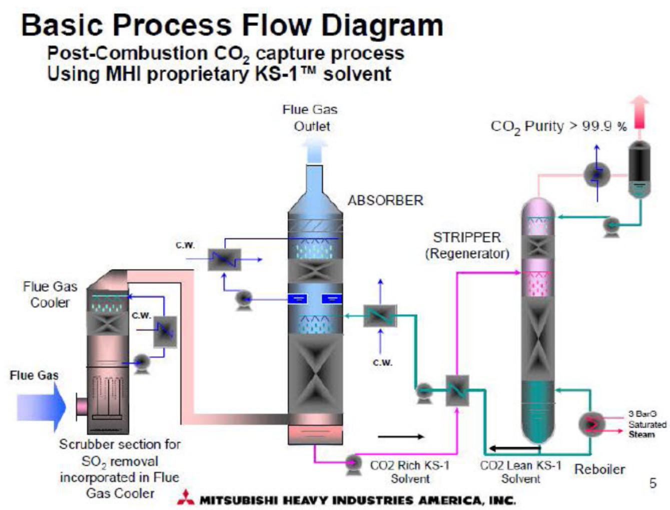

Figure 2d. Basic amine gas scrubber. (Global CCS Institute)

In the above picture, the flue gas outlet contains the natural gas that will be transported to the pipeline. The carbon dioxide is relatively pure when it is removed, so it can be used for other processes, or simply disposed of. We plan to transport the flue gas to a compressor to be loaded onto trucks. The price of the amine scrubber comes out to approximately $2.4 million [10].

2.2.5. Natural Gas Transportation

In order for the cleaned natural gas to be transported to the landfill, it must first be compressed to 3,000 psi. At ambient temperature, there is 19,400 m^3/day of gas at approximately 14.7 psi. When compressed to 3,000 psi, the resulting natural gas output for a day occupies a volume of 94.83 m^3. This calculation was made using the assumptions that the gas behaves ideally, which introduces some error, but is a good approximation for gas flow and transportation. Based on the calculated gas output flow and pressure, we chose a portable compressor from Alibaba.

The Atlas Copco XAS186Dd diesel portable 3000 psi air compressor (Alibaba) was the compressor that we ultimately decided on for our design. Its output capacity is 11.1 m^3/min, which would be enough for three digesters. If a fourth digester was implemented, then a second air compressor would need to be purchased to accommodate the increased gas flow. Each compressor costs $100,000, and there is no installation fee as the compressors are each transportable systems.

Although we plan on compressing the gas then loading it into tube trailers, we intent to implement storage tanks in case the compressor should malfunction. Storage tanks would allow for continued gas production while the compressor is fixed. Upon researching holding tank options, we found Portable PVC Methane Gas Tanks, which essentially act as large balloons that are capable of storing gas. These were determined to be the best storage option for several reasons including capacity, price, and resistance to wear.

Each of the methane gas tanks is capable of holding up to 2,000 m^3 of gas. Considering a maximum output of a single digester being 250 scfm, three digesters running, and the gas after scrubbing being 96.7% methane, Clean Fuel Partners would be producing 19,400 m^3/day of clean methane gas. This means that in order to hold all of the gas produced in one day, ten storage tanks would be required. We recommend purchasing those ten tanks in case something were to happen to the compressor. The price for each 2,000 m^3 capacity tank is $400, so in total the price comes to $4,000.

Portable methane tanks are designed to be used with, or in place of anaerobic digesters. Because of this, they are designed to have a high resistance to corrosion, wear, and temperature changes. The tanks can withstand temperatures below 40°C, and are resistant to penetration. Approximately 95% of portable methane tanks are still functional after 25 years of use. Concrete lined pits need to be put in place in order to use the portable tanks. Each pit must have dimensions of 5x3x1.4 m, and be lined with concrete that is at least 120 mm thick. The pit would be the majority of the cost of implementing these tanks.

Once the methane is at a higher purity, it needs to be transported to the injection point. From Clean Fuel Partners to the Dane County Landfill is approximately 23 miles. The gas needs to be compressed to 3,000 psi before transportation. On average, Clean Fuel Partners produces 683,640 scf of gas per day. Once this gas is compressed, that would be 3,350 scf at 3,000 psi of gas produced in one day.

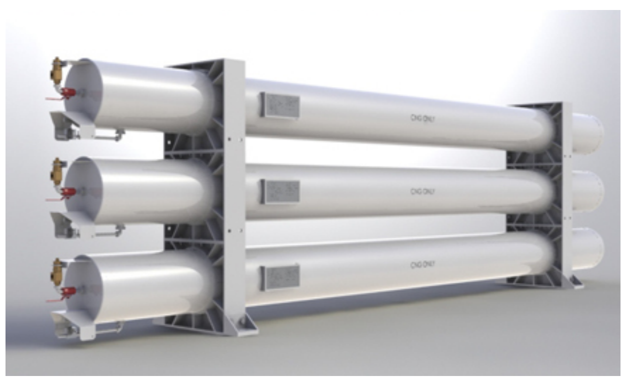

Figure 2e. Image of the 24 ft. 3 vessel assembly. (Wilco Fab)

A 24-foot, three vessel assembly would hold the gas for transportation as shown in (Figure 2e.). Each vessel can hold approximately 9,077 scf (shown in Appendix: Calculation D). To fill one vessel, it would take approximately 2.7 days and 8.1 days to fill the assembly (all three tanks). Logistically, two of the vessel assembly would be purchased. The assembly would rotate between the injection point, where the gas would be injected into the pipeline, and Clean

Fuel Partners, where the tanks would fill up with the natural gas. The 3 tank assembly can be purchased from Wilco. They also offer a 12 foot 3 vessel assembly and 48 inch spheres.

To transport these vessels, Clean Fuel Partners could outsource trucking companies. FedEx Freight appears to be a viable option for shipping these vessels. Several factors need to be taken into place for the pricing of the transportation. The vessels would only need to be rotated approximately every 8 days, due to the amount of gas produced in one day. The weight of the 3-tank assembly is 31,225 lbs when it is empty and 32,630 lbs when it is filled with gas [17]. The estimated cost for the transportation for one-way is approximately $500-1000 ranging on discount options. This fee would include the hazardous fee for shipping flammable gas [18].

2.2.6. Future Outlook

In conclusion, the initial capital investments of the gas treatment infrastructure, compressor, and transportation tubes approximate $2,510,000. Recurring costs of $500-$1000 per every 8 days for transportation, and an injection fee paid to Dane county of roughly $2/MMBTU must also be considered in the pursuit of this gas injection alternative. Placing focus on the initial capital investments alone, CFP could offset these costs by making $2,557,982 in one year under the assumption that they operate 3 digesters using only D3 fuels at $2.00/RIN. Under a different scenario, it would take approximately 270 days to offset these costs assuming an adjusted input stream (including D5 fuels), and a D3 RIN value of $2.00/RIN. Given that CFP has 2 operating digesters, 1 idle digester and the infrastructure for a 4th, there would be a significant upsurge in revenue while operating more digesters than the current system. Additionally, the $2/RIN value used in calculations yields a conservative estimation of revenue as RINs most typically fluctuate between $2.50 and $3.00/RIN. It is a notable added benefit that D3 RINs are the most valuable, and congressional goals call for an elevated utilization of them in years to come. Lastly, there is room for additional financial streams from the removal of the two 1 MW generators used by CFP. Generators of this make and model under the current market would sell for roughly between $80,000 and $120,000, but it is worth noting that this is a very liquid market. Aside from the sale price, there are many O&M costs that would be avoided given the removal of the generators from the system. Overall, a transition to biomethane from the current electricity generation model would be safe, sustainable, and viable given the proper precautions and a pragmatic approach.

3. Fiber Byproduct

3.1. Biofertilizer Pellet Alternative

Figure 3a: Image of Fiber Pellets.

Fiber from digestate can certainly have many applications, but when dealing with it in bulk flow rates, it became clear that the most feasible option would be to produce biofertilizer pellets (Figure 3a). This marketable product will be the future for fiber at Clean Fuel Partners. Biofertilizer offers clear benefits regarding soil health, however the pellet form-factor gives it additional advantageous characteristics. The fiber found in the byproduct of the anaerobic digestion process acts as a sponge for various nutrients, such as nitrogen, phosphorus, and potassium. In our case, the fiber from Clean Fuel Partners contains 12/9/6 (NPK), and it is in fact very important that we take that phosphorus and relocate it outside the Yahara Watershed [3]. Although it has no business here, the phosphorus and other nutrients taken in by the fiber could serve as an extremely viable fertilizer or soil supplement. Pelletizing the fiber will not only increase the fertilizers effectiveness, it is simply the key that makes this entire process profitable. Fertilizer in pelleted form can be augered at extremely consistent rates, while its shape still allows it to be blown through a blower at high mass flow rates as well. The pellet extrusion process leads them to be extremely dry and dense in nature. Once placed in the soil, moisture is absorbed by the pellets, and they break back up into fibrous particles. This ultimately aids with the soils moisture retention and soil structure. The dense pellet form, absent of most of its water, allows for much more compact storage, resulting in massively reduced transportation costs. Ultimately, pelletizing the fiber at Clean Fuel Partners offers a much more handleable, transportable, and eventually marketable product.

3.2. Equipment Necessary

Figure 3b: Dryer running at Clean Fuel Partners currently.

Launching the process to produce biofertilizer pellets will obviously begin with an investment in some new assets. Clean Fuel Partners will need to implement two machines to pelletize in the future. A new dryer will have to replace the dryer currently running onsite, shown above. Currently, exhaust heat from one of the generators is piped underground to dry the fiber feeding the dryer (Figure 3b). This exhaust heat is approximately 550°F by the time it reaches the dryer [3]. Using this system is sustainable, as it does not require any extra cost for gas to reduce the moisture content of the fiber. However, this dryer is faced with some serious problems. As stated earlier, the two generators on site at Clean Fuel Partners will be sold. This means that there will not be any exhaust heat for the dryer to function, soon making it obsolete. A pellet mill is another piece of machinery needed in the production of biofertilizer pellets. This piece of equipment takes dried fiber, compresses it, and extrudes it through a die. There currently is not a pellet mill at Clean Fuel Partners, making it necessary to purchase one. A new dryer is an intermediate step in handling the wet fiber, leading to the pellet mill operation.

3.3. Proposed New Dryer

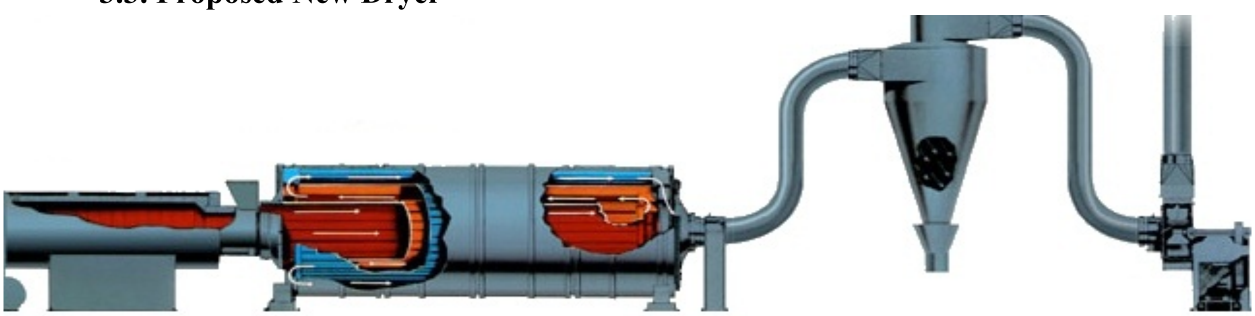

Figure 3c: Baker-Rullman Triple-pass rotary drum drying system. (Baker-rullman)

Throughout this project we've been in contact with Baker-Rullman, a rotary drum dryer company based out of Watertown, Wisconsin. The dryer we chose is to replace the existing one is a triple pass-type dryer. The reason why we went with a triple-pass design is because it remains a superior dehydration system that optimizes operating costs, efficiency, and end product consistency [2]. Wet fiber enters the cylinder in the dryer (Figure 3c), that's propelled through the drying system by a hot air stream. This hot air steam moves through three nested concentric cylinders that continuously rotate together. Once particles lose 60% of their moisture, they move down to the next cylinder. At desired moisture levels, the dried particles fall through the outermost cylinder and are carried through to the end of the system. On the far right of (Figure 3c), there's a cyclone that removes the suspended particulate fiber before the exhaust fan located farthest to the right.

The heat source for this dryer can be natural gas, propane, or biogas. Clean Fuel Partners choose to use natural gas to feed the gas burner within the dryer, as propane is expensive compared to natural gas. Using biogas was considered, however it is much more corrosive, and would require a more robust, expensive system. Additionally, this way all the biogas production will go towards producing purified gas for transportation to the injection point. Talking with Bruce Miller at Baker-Rullman, he recommended Clean Fuel Partners should go with the Model SD 75-22 dryer. This dryer with reduce the moisture content of the wet fiber to 10-15% (Figure 3d), which is optimal input for a pellet mill. Based on the dimensions of the dryer, installation would occur in the same solids building the current dryer is located in with room for a pellet mill. Model SD 75-22 can handle up to 9,000 lbs/hr (Figure 3d) of wet fiber. Clean Fuel Partners only produces 3,200 lb/hr of wet fiber with 2 digesters, 6,400 lb/hr of wet fiber with 4 digesters (Table 1). We sized the dryer to be slightly bigger than what our needs require so the system does not continuously run at full load.

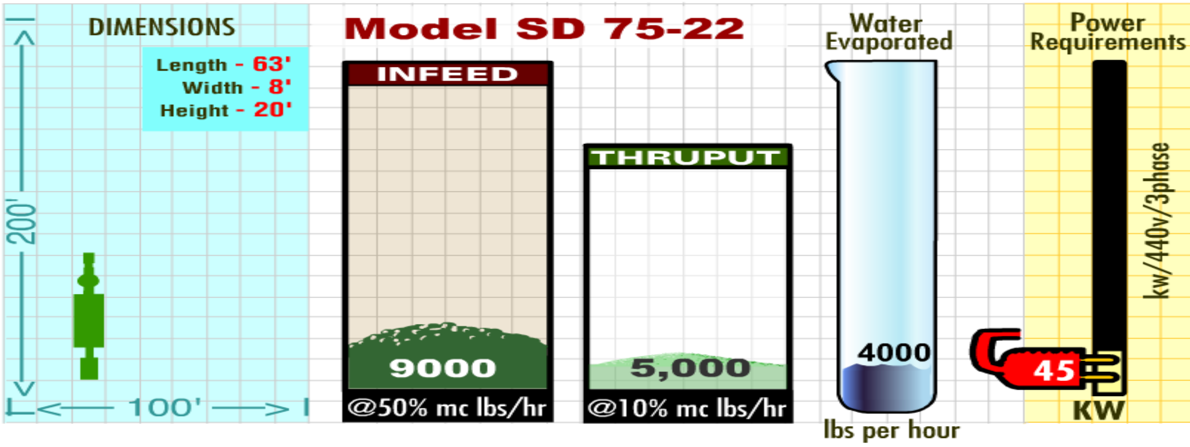

Figure 3d: Model SD 75-22 triple-pass rotary drum dryer from Baker-Rullman. (Baker-Rullman)

Baker-Rullman will only provide the installation of the drying system. They do not provide a way to get the fiber to the dryer or movement of the fiber after reduced to the desirable moisture content. This is not a problem for Clean Fuel Partners. Based on (Figure 3b), located directly in front of the scissors lift is a material handling system for the current dryer. There is a blue conveyor system along the back wall moving the fiber from the centrifuge building. Wet fiber is dropped from the conveyors into feed augers that distribute the wet fiber into the dryer. There is a white cyclone already in place that connects to the exhaust fan (Figure 3b). The exhaust fan creates a vacuum, pulling the steam created by the evaporation of water within the fiber. The solids (fiber) building at Clean Fuel Partners already has a conveyor and auger system feeding the dryer, a cyclone to remove suspended fiber particulates, and an exhaust fan to remove water evaporated. These pieces of the drying process can be transferred over to the operation of the new dryer Clean Fuel Partners should implement.

3.4. Economic Feasibility - Dryer

Current Fiber Production		
Truck Weight (lbs)		39,250
Truck and Fiber Weight (lbs)		90,000
Fiber Weight (lbs)		50,750
Fiber Production (tuckloads/day)		1.5
	*2 Digesters (lbs/hr)	3,200
	*4 Digesters (lbs/hr)	6,400

Table 3a: Current fiber production at Clean Fuel Partners (*Equation used found in Appendix: Calculation E).

Cost of Dryer Implementation and Operating	
Dryer Model	SD 75-22
Price of Dryer	$480,000
Amount of Gas needed for Dyer	6 million Btu/hr
Price of Nautral Gas	$0.55/therm
Operation Cost for Gas	$792/day
Power Required	45 kW
Price of Electricity	$0.05/kWh
Operation Cost for Electricity	$54/day
Total Operation Cost (Gas and Electricity)	$846/day

Table 3b: Economic feasibility of implementing the Model SD 75-22 dryer at Clean Fuel Partners (Equation used found in Appendix: Calculations F).

Summarizing the information provided above. A farm east of Madison hauls approximately 1.5 trailer loads of fiber a day to their farm. Clean Fuel Partners can't outsource the fiber for any use within the Yahara River shed, because DNR prohibits this action in trying to reduce phosphorus entering the watershed [3]. With potentially four digesters running at the facility, the peak fiber production Clean Fuel Partners will have approximately 6,400 lb/hr feeding the dryer. The operation cost to process this amount of fiber with be electrical and gas use. Gas use per hour was given to us by Bruce Miller, from Baker-Rullman based on wet fiber input feeding the drying system. Electric use came from (Table 3b), making the operating cost of the Model SD 75-22 approximately $846/day. With this operating cost and moisture reduction of the wet fiber, the dry fiber end product is ready for pelletizing. A pellet mill will bring profit to Clean Fuel Partners.

3.5. New Pelletizer

California Pellet Mill (CPM) Roskamp Champion was a pellet mill company recommended by Troy Runge, a biological systems engineer at UW-Madison. Roskamp Champion is based out of Waterloo, Iowa. Our group was in contact with David Gramman, an application engineer at CPM. Based on a theoretical moisture content of dry fiber coming out of the Model SD 75-22 at 10-15% (Figure 3d.), David Gramman recommend Clean Fuel Partners to implement a 7,900 series pellet mill. Specifically, within this series, it is a 7930-8 pellet mill. Clean Fuel Partners could directly and continuously feed this pelletizer with fiber coming from the dryer. Troy Runge recommended to use a ⅜ inch rotary die. The 7930-8 pellet mill will cost $300,000 using 250 kW for operation. This pellet mill was appropriately sized to handle 5,000 lb/hr of dry fiber coming out of the Model SD 75-22 [4]. Theoretically when a fourth digester is in operation, this pellet mill will still have the capacity to pelletize the ‘worst-case’ fiber flow rate scenario.

3.6. Economic Feasibility - Pelletizer

Econcomic Feasibility of Pelletizer			
Dry Fiber From Dryer		2 Digesters	1,800 lb/hr
		4 Digesters	3,600 lb/hr
Cost of Pelletizer Operation		Initial Cost:	$300,000
		Daily Electrical Use	$300/day
Profit from Biofertilitzer Pellets	2 Digesters	Dry Fiber Produced	21.6 ton/day
		at $110/ton	$2,367/day
		at $200/ton	$4,320/day
	4 Digesters	Dry Fiber Produced	43.2 ton/day
		at $110/ton	$4,752/day
		at $200/ton	$8,640/day

Table 3.c: Economic feasibility of a pellet mill incorporated at Clean Fuel Partners (Equation used found in Appendix: Calculation G, H). Biofertilizer price $110-$200/ton [25]

Table 3.c represents why implementing a pellet mill at Clean Fuel Partners will financially benefit the company. The pellet mill and dryer will have a payback period of approximately 180 days, given the pelletized fiber will produce a revenue of $5,500/day. This is an average of the possible income produced by the biofertilizer.

3.7. Fiber Solution Overview

Preliminary economic calculations suggest that pelletizing the fiber at Clean Fuel Partners would not only curb their fiber surplus, but it could actually serve as a source of revenue. Biofertilizer is a marketable product that aids in soil health and soil structure, and its pellet form enhances functionality while slashing transportation costs. It would require Clean Fuel Partners to invest in two crucial pieces of machinery; a drum dryer capable of drying solids to 10-15% MC, and a pellet mill. This $780,000 investment could be payed off within the first year of operation, where all sales following are simply profit. Even worst case scenarios of our economic analysis would allow for perfectly reasonable payback periods and a trickle of revenue. This undoubtedly puts Clean Fuel Partners in a better situation than they previously had on their hands, where in some cases addressing their fiber surplus actually costed them money.

4. Evaluation/ Results

4.1. Overview

Our team approached this design challenge by initially gathering research, information, and data from numerous sources. Solid communication was established with John Haeckel early on, considering two of our team members are employees at Clean Fuel Partners. John was a major source of pertinent information for our group, although our two team members, Kevin and Riley, came into this project with an outstanding base of knowledge. Additionally, we took every opportunity we could to reach out to established businesses and companies in the field for their expertise. It is thanks to the many phone conversations that we were able to get accurate and realistic figures that would otherwise only be available to a serious inquirer. Gathering research and referencing online databases with existing information on this topic provided us with both base knowledge as well as facts to fill in voids in our understanding.

4.2. Project Analysis

4.2.1. Injection Point Strengths

In assessing the feasibility of this design, we have come across many things to consider. The injection point has several key advantages that make it our most viable design option. Potential revenue based on RINs is significantly higher than any of the other viable options for what to do with the biogas. Also, the technology that needs to be implemented in order to clean the gas and inject it into the pipeline is simple to acquire and operate. This will decrease operations costs, as well as installation costs, as there were no new technologies being invented for this process.

The fiber pelletizer is also highly beneficial for the Yahara watershed as it will allow Clean Fuel Partners to transport all of the excess nutrients from cow manure out of the area. This will give areas in need of nutrients a boost, while keeping the watershed free of contamination. The pellets are also the only viable economic option for the fiber byproduct. Cow bedding generates only a small amount of money for the company, and does not need to be replaced very often.

4.2.2. Injection Point Weaknesses

The natural gas injection point and RINs are not without their downfalls however. In order to implement RINs, a third party would need to come in and verify the fuel that is being used to produce the natural gas is compliant with RIN guidelines. This would be an added cost. Also, if we choose to have a third party constantly moderating the process, it would cost approximately a fourth of the revenue gained from selling the carbon credits. This problem can be mitigated by hiring someone in house to do it, or by transferring the responsibility to one of the current employees.

Another issue is the volatility of the market. RINs do not have a constant value, so the revenue generation would be changing from month to month. The inflow of manure is not a constant value either. It depends on the cows being used and how much the farm feeds them. This could have a severe impact on daily gas production. Finally, the upfront cost of implementing all of the new machinery would be significant, at approximately $2.5 million to start out. This would be offset by revenue, but it is still an important consideration.

If the company wishes to install another digester, they will need to worry about costs for that, as well as costs for transporting in more manure from nearby farms as the current three have too small of a manure production capability to warrant the installation of another digester. Also because of the restriction of 75% of the gas coming from cellulosic material, more manure needs to be trucked in anyway, in order to supplement the current feed. If this is not done, then the gas producing capabilities of the digesters will not be fully utilized.

For the fiber option, the upfront cost of technology is also significant. Also, the pellets would need to be transported outside of the watershed, which would accrue transportation costs. Once again, the volatility of the market would be something to consider here, as Clean Fuel Partners would have to sell the pellets through a third party. This would include vendor costs, as well as finding an area of the Midwest that would be in need of this type of fertilizer on a wide scale.

4.2.3. Straightforward Project Aspects

Some of the straightforward aspects of this project include staying in contact with Clean Fuel Partners. Two members of our team work for the company, and have a close working relationship with the owner, John Haeckel. He was also very helpful whenever we emailed him with specific questions. A lot of the technologies that we chose to implement also had extensive documentation, making them easy to find information on.

4.2.4. Project Difficulties

Several aspects of this project were not quite so straightforward. Attempting to find information on carbon credits proved to be much more difficult than initially anticipated. Eventually we were able to contact a member of the EPA who was willing to talk in depth about the carbon credit program, and give advice on which options to pursue given our current situation. Another option that was difficult to sort out was the transportation to the pipeline. Due to the low gas output of the digesters, many companies did not think it economically feasible to partner with Clean fuel Partners in this endeavor. Eventually FedEx freight gave a quote for the transportation costs, but they were the fourth company we had to contact. The fiber byproduct design was also very in depth, and we had to find the only economical option.

4.2.5. Sustainability Impacts

Carbon Credits have an inherent sustainability issue, wherein by purchasing carbon credits from Clean Fuel Partners, companies in California and other states are able to use less sustainable practices. This does have an adverse effect on the environment in the area where non-sustainable businesses are practicing. However, in having to pay to pollute, they are incentivized to slowly convert to more sustainable practices to save money. Therefore, carbon credits are beneficial for long term sustainability goals.

The natural gas production at CFP is sustainable, and it is beneficial to the environment in that it prevents excess nutrients from entering the watershed. The current biogas production of CFP when converted to natural gas would be enough to power 990,000 homes per year in America, assuming an average consumption of 168 scfd per household (Teco). If CFP decided to implement a fourth digester, this means that they would be able to power nearly 2 million homes in a year, sustainably. Natural gas comes with drawbacks of course, it does produce small amounts of greenhouse gases when burned, but it is significantly better for the environment than coal or gasoline.

4.3. Next Steps/Recommendations

4.3.1. Investments Required

Various technologies are essential in the production of a higher purity, compressed methane gas. The initial investment associated with each necessary equipment is listed below in Table 4a.

Equipment	Capital Cost ($)
Scrubber	2,400,000
Compressor	100,000
Dryer	480,000
Pelletizer	300,000

Table 4a. This table shows the estimated capital cost of each technology listed.

All four of these technologies are critical for the overall design of this project. However, the equipment will require maintenance in the future. Another cost required with this system is the operating costs for each equipment that will be implemented.

Additionally, there are other costs to consider for this project. The gas needs to be placed in a container for shipment. There are several options for the types of tanks to be used for transportation. Wilco Machine & Fab Inc offers three different styles: the 24-foot 3-vessel assembly, 12-foot 3-vessel assembly, and 48 inch spheres. If any of the equipment was malfunctioning, we could also invest in storage for the gas.

4.3.2. Client Utilizations

Clean Fuel partners will be able to use our design as a guideline for their transition away from electricity production. Even if they do not decide to pursue the D3 RIN option, they could use a combined system of D3 and D5 RINs to make a profit. Or they could produce natural gas and use it for other applications within the state of Wisconsin. If this is the case, then the technologies that we have researched and companies we have been in contact with would be a valuable resource for them. Also, the fiber option presented in this report is helpful for the local Dane County government in deciding what to do with the excess nutrients from farms. It could serve as a guideline for not only this digester, but for other farms and companies in the area.

4.3.3. Natural Gas Transportation Decision

To transport the gas to the injection point, there are several options. The gas could be transported via outsourced flatbed trucking companies, implement piping from Clean Fuel Partners to the injection point, railroad, or administer trucking within Clean Fuel Partners. The most realistic options would be either outsourcing a trucking company or having a truck onsite and an employee transport the natural gas to the injection point.

4.3.4. Carbon Credit Third Party

To initiate the transition to the RIN carbon credit system, CFP would consult a third-party accreditation company to test the renewable fuels for cellulosic content, perform any converted fraction calculations as needed, verify compliance program standards, and generally ensure that there are no withstanding concerns. As mentioned, these upfront fees can range from $10-20,000, but typically are at least $20,000. Moreover, flagging CFP's D3 RINs as "Q-RINs" is an unavoidable, recurring cost of $20-$40,000 per year, and therefore incentive for CFP to consider handling RIN transactions in house to avoid costs in addition to these. After the initial investment, CFP may continue to hire out a third-party consultant such as EcoEngineers or Weaver, or facilitate transactions on their own. Given the other costs incurred, it may be more beneficial to train employees on navigating the transaction system, or perhaps hiring an additional staff member as a RIN transaction specialist.

5. Conclusion

Clean Fuel Partners and the Dane County government tasked our team to come up with both an alternative use for the biogas and the fiber produced by the CFP digesters. For the biogas, which is currently being used to produce electricity, we found that the most viable option is to inject it into a natural gas pipeline. Once it is in the pipeline, revenue can be earned based on carbon credits known as RINs. There are several steps that must occur before the gas can be put into a pipeline, because biogas is corrosive and contains impurities.

Carbon Credits are a highly rewarding system by which creators of renewably sourced natural gas and other resources can be paid for the use of their product. RINs, or renewable identification numbers, range in price from $2-3/BTU. Running two digesters, CFP would be able to generate a revenue in the range of $2.5-3.8 million based on current manure input flows. This would be more than enough to offset initial costs of the technologies needed to make natural gas from biogas. Carbon Credits do have the downside of allowing pollution elsewhere in the country, but provide an economic incentive to be more sustainable for businesses across the country.

In order to make natural gas economical for CFP, several costs must be considered. The biogas product needs to be scrubbed of impurities using an amine scrubber which will remove the majority of the carbon dioxide and hydrogen sulfide impurities, while only losing a minimal amount of natural gas. This technology costs approximately 2.4 million dollars, and is the largest upfront cost associated with our design. The gas that comes out of the scrubber is then considered natural gas, as it is almost entirely methane. Natural gas has to be compressed in order to be transported, so a compressor must be purchased at $100,000. Transportation to the Dane County landfill's injection point by FedEx Freight would cost anywhere in a range of

$500-10,000 every eight days. Clean Fuel Partners will also have to pay the landfill to inject their methane gas there. This number has yet to be determined, and should be revisited at a later date.

Another aspect of this design that we considered is the possibility that either the tube trailers or the compressor could malfunction. In order to account for this possibility, we also included portable methane storage tanks in our final design. These tanks could be taken out if they are needed, and stored if not. The cost for tanks to store all of the gas produced from 3 digesters in one day is only $4,000, thus we felt that it was a smart investment.

The Dane County government wanted our team to find a use for the fiber byproduct produced during the anaerobic digestion process. This fiber is potentially harmful to the environment as it contains excess nutrients that if left unchecked could seep into the Yahara watershed. A surplus of nutrients in the water could cause algal blooms and other detrimental effects. Our team came up with the option of pelletizing the fiber, so that it can be used as a biofertilizer. The pelletized fiber has a much lower water content than the current fiber output, thus lowering shipping costs. Due to the low price for transporting these pellets, they can easily be transported outside of the watershed to an area where the nutrients will be beneficial to the land. As with any process, this also includes several costs that must be considered.

The pelletized fiber must go through an intensive drying process to remove the excess water weight. The rotary drum dryer that was selected for this process costs $480,000 to purchase. After the fiber is dried, it must be compressed into the final pellet shape, which takes a pellet mills. Pellet mills are also a significant investment of $300,000, totaling $780,000 for the initial investment on fiber. An upside to this process is that the pelletized fiber can be sold to farms and other consumers, which will generate revenue. Based on the assumption that the fiber from a day can be sold for anywhere between $2500-8500, it would take approximately 180 days to pay off the initial investment into the fiber.

Though the upfront costs for this project seem to be extreme, based on our calculated revenues, all of the new machinery could be paid off within one to two years at most. The most difficult part about implementing this design will be having another company come in and work with Clean Fuel Partners on starting the carbon credit program. Once the RINs for CFP's natural gas have been established, it should be a relatively smooth process to run.

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7. Appendix
A. Calculations and Equations

$$\boxed{\frac{90{,}000 \text{ gal manure}}{1 \text{ day}} * \frac{3.3382 \text{ lb manure}}{1 \text{ gal manure}} * \frac{1 \text{ gal diesel}}{55 \text{ lb manure}} = \mathbf{5,500} \ \frac{\textbf{gal diesel}}{\textbf{day}}}$$

Calculation A. This calculation provides how many gallons of diesel can be produced per day based on the input amount of manure on the high end.

$$\boxed{\frac{90{,}000 \text{ gal manure}}{1 \text{ day}} * \frac{3.3382 \text{ lb manure}}{1 \text{ gal manure}} * \frac{1 \text{ gal diesel}}{135 \text{ lb manure}} = \mathbf{2,200} \ \frac{\textbf{gal diesel}}{\textbf{day}}}$$

Calculation B. This calculation provides how many gallons of diesel can be produced per day based on the input amount of manure on the low end.

$$\boxed{\frac{3{,}800 \text{ gal diesel}}{1 \text{ day}} * \frac{\$ \ 1.50}{1 \text{ gal diesel}} = \mathbf{\$5,800/day}}$$

Calculation C. This calculation provides how many gallons of diesel can be produced per day based on the input amount of manure on the low end.

$$\boxed{SCF(psi) = 10{,}900 + \frac{12{,}115 - 10{,}900}{5{,}500 - 4{,}500}(3{,}000 - \ 4{,}500) = 9077.5 \ SCF}$$

Calculation D. This calculation provides how much standard cubic feet at 3,000 psi can fit into one of vessels on the 24 foot 3 vessel assembly based on 12,115 scf at 5,500 psi and 10,900 scf at 4,500 psi.

$$\boxed{(Number\ of\ Digesters) * (90{,}000\ lbs\ - 39{,}250\ lbs) * \frac{1.5\ loads}{1\ day} * \frac{1\ day}{24\ hours} = \text{Pounds of Fiber Produced per hour}}$$

Calculation E. This calculation provides the amount of fiber produced based on the number of digesters operating.

Gas

$$\frac{6\ million\ Btu}{1\ hour} * \frac{1\ therm}{100{,}000\ therm} * \frac{\$0.55}{1\ therm} = \$792 \text{ per day for gas}$$

Electricity

$$45\ kW * \frac{\$0.05}{kWh} * \frac{24\ hours}{1\ day} = \$54\ per\ day\ for\ electricity$$

Calculation F. This calculation demonstrates the operating cost for gas and electricity for the Dryer SD 75-22 .

$$\text{2 Digesters:} \quad \frac{3{,}200\ lb}{1\ hour} * \frac{5}{9} = 1{,}800 \text{ lb per hour to pelletizer}$$

$$\text{4 Digesters:} \quad \frac{6{,}400\ lb}{1\ hour} * \frac{5}{9} = 3{,}600 \text{ lb per hour to pelletizer}$$

Calculation G. This calculation shows how much dry fiber is produced from the Dryer SD 75-22.

$$\frac{\$0.05}{kWh} * 250\ kW \frac{24\ hours}{1\ day} = \$300\ per\ day$$

Calculation H. This calculation displays the operating cost for electricity of the pelletizer.

$$\frac{360{,}000scf}{day \cdot digester} * 0.633\ Natural\ gas * \frac{1scf}{DK} * 1E-6\frac{DK}{BTU} * \frac{77000\ BTU}{RIN} * \frac{0.07701848\ DK}{RIN}$$

Calculation I. This calculation is used to determine revenue based on different input streams. This value is for one digester, and can be used with whatever value of RIN desired

B. Figures and Pictures

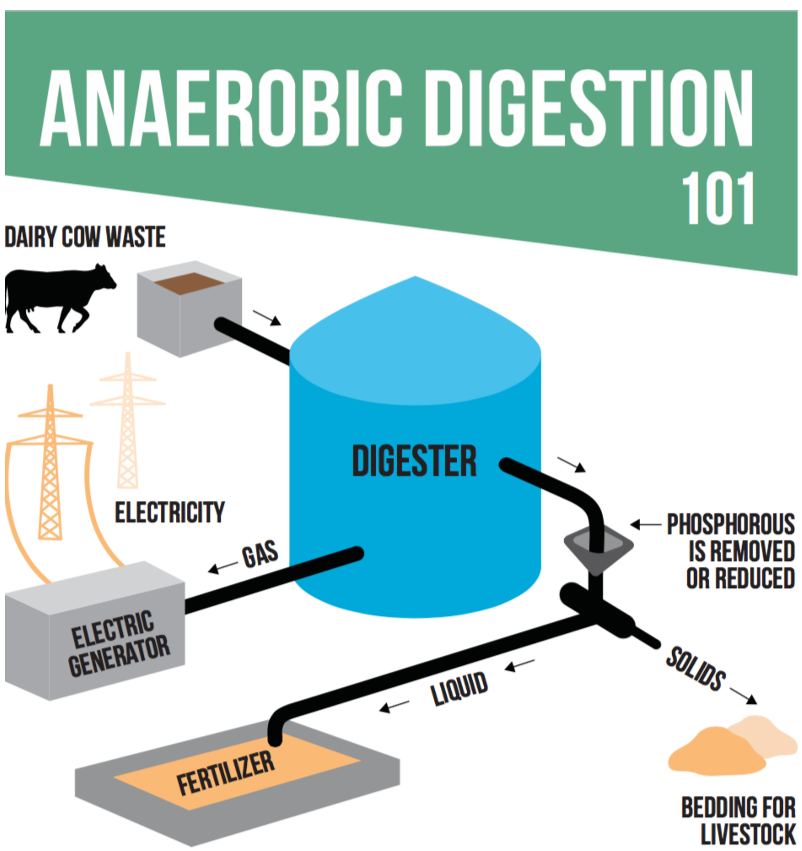

Figure A. This image demonstrates the basic process of a digester.

Figure B: Atlas Copco XAS186Dd diesel portable 3000 psi air compressor (Alibaba).

Figure C: Methane gas portable pvc storage tanks (Alibaba).

C. Tables

Rege				higher than 10000 m³/day.	for H_2S and CO_2	
	Ferric oxide		$2Fe(OH) + 3H_2S \rightarrow Fe_2S_3 + 6H_2O$ $Fe(OH)_2 + H_2S \rightarrow FeS + 2H_2O$ $2Fe_2S_3 + 3O2 + 6H_2O \rightarrow 4Fe(OH)_3 + 3S_2$ $2FeS + O_2 + 2H_2O \rightarrow 2Fe(OH) + S_2$	Low scale	Most used. High removal efficiency(>99 %)	Inappropriate for medium scale application Reagent disposal
	Activated carbon		Adsorption	Low scale	Elemental S is formed	Absorbs CH_4
No regenerative	Solid reagents	Zinc oxides	$ZnO + H_2S \rightarrow ZnS + H_2O$	0.3-500 kg/day of H_2S.	Low cost high selectivity operational flexibility low CO2	Disposal of saturated reagent
		Iron oxides	$Fe_2O_3 + H_2S \rightarrow 2FeS + S + 3H_2O$ $Fe_3O_4 + H_2S \rightarrow 3FeS + S + 4H_2O$			
		Sodium nitrite	$3H_2S + NaNO_2 \rightarrow NH_3 + 3S + NaOH + XNO_x$ $2NaOH + H_2S \rightarrow Na_2S + 2H_2O$			
	Solvents	Caustic wash	$CaO + H_2O \rightarrow Ca(OH)_2$ $Ca(OH) + H_2O \rightarrow Ca(CO)_3 + H_2O$ $CaO + H_2S \rightarrow CaS + H_2O$	0-300 ppm H_2S concentration	Elemental S is formed Low costs Low removal	Operational difficulties Disposal of
		Permanganate	$3H_2S + 2KMnO_4 \rightarrow 3S + 2H_2O + 2MnO_2 + 2KOH$			

Table A: Scrubbing Technology information [13].

D3-Adding Manure from Other Sources Revenue				
$/RIN	**1**	**2**	**3**	**4**
$2.00	$5,917.54	$11,835.08	$17,752.62	$23,670.16
$2.50	$7,396.93	$14,793.85	$22,190.78	$29,587.70
$3.00	$8,876.31	$17,752.62	$26,628.93	$35,505.24
D3 - Pure Manure Revenue				
$/RIN	**1**	**2**	**3**	**4**
$2.00	$2,336.06	$4,672.11	$7,008.17	$9,344.23
$2.50	$2,920.07	$5,840.14	$8,760.21	$11,680.28
$3.00	$3,504.08	$7,008.17	$10,512.25	$14,016.34
D3 - Adjusted Input Streams Revenue				
$/RIN	**1**	**2**	**3**	**4**
$2.00	$3,114.74	$6,229.48	$9,344.23	$12,458.97
$2.50	$3,893.43	$7,786.86	$11,680.28	$15,573.71
$3.00	$4,672.11	$9,344.23	$14,016.34	$18,688.45

Table B: Potential Revenue based on different input streams.

About UniverCity Year

UniverCity Year is a three-year partnership between UW-Madison and one community in Wisconsin. The community partner identifies sustainability and livability projects that would benefit from UW-Madison expertise. Faculty from across the university incorporate these projects into their courses with graduate students and upper-level undergraduate students. UniverCity Year staff provide administrative support to faculty, students and the partner community to ensure the collaboration's success. The result is on-the-ground impact and momentum for a community working toward a more sustainable and livable future.

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