Anaerobic Digesters Resource Assessment

for

PacifiCorp

Washington Service Territory

Prepared for

PACIFICORP

HARRIS GROUP INC.

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ANAEROBIC DIGESTERS RESOURCE ASSESSMENT

PACIFICORP WASHINGTON SERVICE TERRITORY

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SECTION 1 – EXECUTIVE SUMMARY

Introduction

Harris Group Incorporated (“HGI”) has been engaged by PacifiCorp to assess the magnitude of the potential electrical power generation from dairy waste in the State of Washington. The purpose of the assessment is to evaluate the potential for inclusion of the dairy resource in PacifiCorp’s 2015 Integrated Resource Plan (“IRP”).

The 2013 IRP Acknowledgment Letter issued by the Washington Public Utilities Commission requested an analysis of the potential within PacifiCorp’s service territory for anaerobic digesters to provide power generation resources to be included in the IRP.

In this study HGI has included a technical analysis of the potential generation capacity based on a thorough review of the available information on the numbers and sizes of dairies within the PacifiCorp service territory. In addition, HGI has provided an analysis of the Renewable Energy Credit (“REC”) registration potential, greenhouse gas reduction potential, environmental permitting summary, capital investment estimate, and operating cost estimate. Other applications of anaerobic digestion that may exist within PacifiCorp’s service territory are beyond the scope of this report. Those other applications are not as readily identifiable or as concentrated as the dairy resources in the Yakima Valley. Other sources of organic feed are also not considered in this assessment due to their diverse nature, additional environmental permitting, and cost associated with the transportation over a large geographic area.

Resource Assessment Overview

Harris Group and professionals within HGI have significant experience in the development of anaerobic digester (“AD”) projects utilizing dairy manure as the primary substrate for biogas production. HGI has developed expertise in the following AD project related activities.

- Biogas Plant Process Design;
- Project Permitting;
- Detailed Plant Design;
- Power Generation and Interconnection;
- Power Purchase Agreements;
- Biogas Conditioning Process Design;
- Natural Gas Compression and Metering;
- Natural Gas Purchase Agreements;
- Resource Evaluation, and
- Plant Operations.

Harris Group has combined our own experience in the development of biogas projects with a thorough literature search that included collecting available data on farm locations and sizes from the State of Washington Departments of Agriculture and Ecology. Based on the available farm information HGI determined the numbers of farms that are located within PacifiCorp’s service territory and began the process of evaluation of those resources and the potential to generate electrical power to satisfy power demand requirements in the service territory.

PacifiCorp Service Territory

PacifiCorp has service areas in the State of Washington that encompass a large concentration of dairies in the Yakima River Valley in Yakima County. A few of the dairies are located near the service territory in Benton County. PacifiCorp has additional service territories in the far southeast parts of the state that encompasses parts of Walla Walla, Columbia, and Garfield Counties. The State of Washington does not report any significant dairy operations in those counties. This report focuses on the dairies in Yakima County.

Figure 1-1 shows the locations of dairies in the State of Washington. Figure 1-2 shows the locations of dairies within PacifiCorp's service territories.

Figure 1-1: State of Washington Dairies

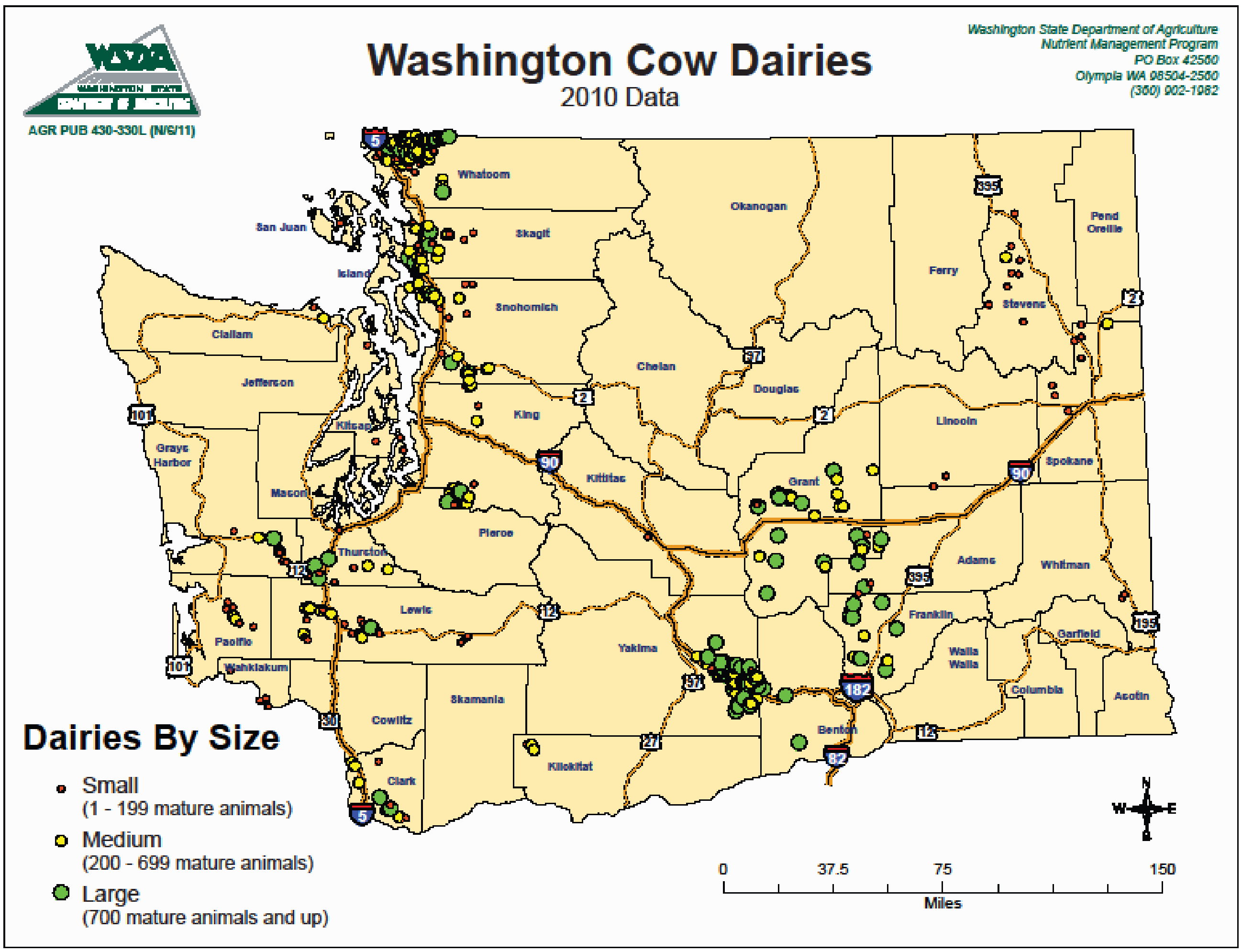
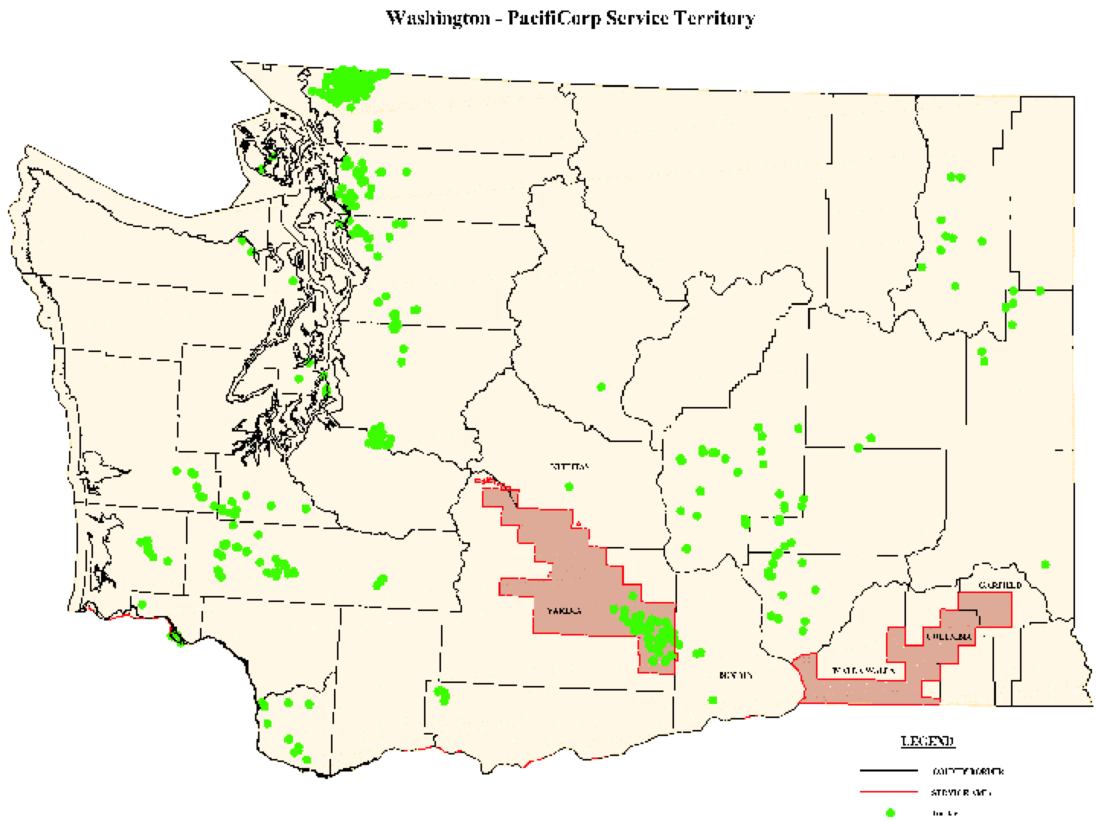


Figure 1-2: Dairies within the PacifiCorp Service Territory

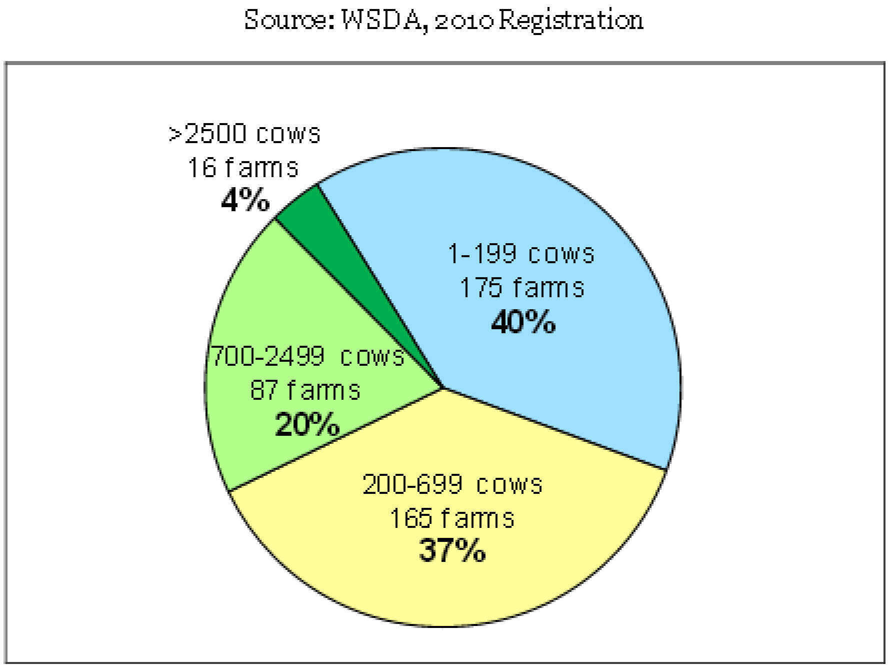


Washington Dairy Background

The Washington State Department of Agriculture ("WSDA") published a report in October 2011 that described the state of the dairy industry and a summary of dairy based digesters.[1] The report states that based on the 2010 registration data for WSDA Nutrient Management plans there are 443 commercial dairies in the State. Figure 1-3 taken from the report shows the size distribution of dairies based on the US EPA size categories developed under the Concentrated Animal Feeding Operation ("CAFO") rules.

[1] WSDA Publication AGR PUB 602-343 (N/10/11) "Washington Dairies and Digesters"

Figure 1-3: Diary Size Distribution in Washington



Milk is Washington's second most valuable agricultural commodity behind apples and ranks Washington as the 10th largest dairy producing state in the US. The report states that the trend in the US in all dairy producing states is towards consolidation into larger and larger farms that develop significant economies of scale to better manage production costs but at the same time concentrates animal wastes in smaller areas. Whatcom County is listed as home to the most dairies while Yakima County is home to largest number of dairy cows indicating a smaller number of larger farms.

The primary focus of this report is the two size ranges of farms shown as 700-2499 cows and greater than 2500 cows. These farms represent the portion of the dairy industry in Washington potentially capable of supporting AD development projects. The total represents approximately 24 percent of the dairies in Washington.

There are currently 10 different digesters in commercial operation in Washington all producing power that range in generator capacity from 400 to 1200 kW. The largest digester is operating in Yakima County at the George DeRuyter & Sons Dairy supplying 1200 kW of power to PacifiCorp. It is reported that all of the digesters operating in Washington add varying amounts of other organic material to the digesters to provide additional biogas for fuel. The State of Washington has enacted specific environmental regulations that allow the digesters to receive pre-consumer organic waste-derived materials under certain conditions without the need for obtaining a solid waste permit. The conditions require that no more than 30 percent of the feed material can come from organic wastes and the digester designs and operations must meet federal standards defined in the USDA Natural Resources Conservation Service Practice Standard 366, Anaerobic Digester. The majority of the digesters in Washington utilize digester technology provided by GHD, Inc, now operating as DVO, Inc.

Observations and Conclusions

The principal observations and opinions that we have reached during our assessment of digestion based power resources in Washington are set forth below.

Section 2 – Digester Technology

1. The use of anaerobic digesters as a combination of waste management and a source of renewable energy is a well developed technology. There has been significant growth in the use of digesters that utilize dairy waste as a feed material in the US over the last 20 years.
2. There are numerous federal and state programs that support the assessment and development of the technology. The State of Washington has a well developed regulatory and acceptance program.
3. There are four primary digester technologies in use in agricultural use.
   - Covered anaerobic lagoons
   - Fixed-film digester
   - Complete-mix digester
   - Plug flow digester
4. The plug flow technology is the predominant technology in use around the US and Washington.
5. The production of biogas is straight forward and the use of biogas as a fuel in reciprocating engines for power production does not pose a significant risk to resource development. Interconnection of those resources to the power grid can be completed without significant technical risk. There may be specific project locations or project capacities where system upgrades may be required.

Section 3 – Power Production Estimate

1. Power estimates have been made using accepted protocols that have been applied to an inventory of resources provided by the State of Washington.
2. The only dairy resources in Washington that are in the service territory maintained by PacifiCorp are in Yakima County. There may be a few dairies in Benton County near the service territory that could be considered.
3. If all of the dairies in Yakima County installed anaerobic digesters, the total installed power would range from approximately 16.0 MW to 26.6 MW. The annual energy production would range from approximately 129 GWh/yr to 214 GWh/yr and would avoid 310,000 to 514,000 tonnes of CO_2e emissions per year.
4. If the size of the AD systems was limited to 500 kW and larger, there are 11 potential projects that would total approximately 10.2 MW and produce approximately 82 GWh/yr and would avoid approximately 197,000 tonnes of CO_2e emissions per year.

Section 4 – Environmental and Regulatory

1. The State of Washington has a well developed and straight forward permit program that specifically addresses anaerobic digester development.
2. With the passage of Initiative 937 in 2006 the State of Washington passed a renewable energy standard that applies to PacifiCorp. The Renewable Portfolio Standard calls for electric utilities that serve more than 25,000 customers to obtain 15 percent of their power from renewable sources by the year 2020. Between January 1, 2012 through December 31, 2015 at least 3 percent of PacifiCorp's load must be supplied by renewable sources. For the period January 1, 2016 through December 31, 2019 the percentage increases to 9 percent. The increase to 15 percent must be met by January 1, 2020.
3. All of the generation that could be produced from AD projects with dairies in the Yakima County service territory would generate REC's that could be registered and traded.
4. REC's can be registered with WREGIS and traded within the WECC states. It is beyond the scope of this assessment to establish the market value of REC's traded within the region.

Section 5 – Development Cost

1. Development or capital costs for development of the resources are based on data provided by the US EPA AgStar Program.
2. The total capital investment estimate that would be required to develop 100 percent of the resources would be approximately $91MM. It is not practical to assume that all projects rise to the level of investment quality. May of the smaller farms would not be practical.
3. Another way to consider the investment is to assume a unit cost per kilowatt of installed capacity to be $3000 to $3500. This figure would be applicable to systems from 500 kW to the maximum size project available in the county. This figure is consistent with Harris Group's experience with similar projects.

Section 6 – Operating Costs

1. Based on the data from the Natural Resources Conservation Service analysis and assuming a plug flow digester design it is estimated that the total operating costs for electrical production are $0.09/kWh. The cost analysis is based on the operating results of nine different projects.
2. The development of AD projects on farms that depend solely on electrical revenue for profitability is not currently economically attractive in an area like Yakima County where wholesale rates for power are relatively low compared to other parts of the country. Projects that meet the requirements of a Qualifying Facility in accordance with the Washington Schedule 37 rates would also not be currently economically attractive based on the value of the power production alone. Projects must include the production and sale of other marketable by products such as compost to reduce the reliance on electrical revenues alone to develop successful projects. Projects must also monetize the value of REC's and Carbon Credits.

SECTION 2 – DIGESTER TECHNOLOGY

Dairy Based Digester Design

Large-scale anaerobic digesters in use on dairy farms in the USA fall into four classifications or types of digesters:

- Covered anaerobic lagoons with a hydraulic retention time (HRT) of 35 to 60 days. Ponds operate at ambient conditions, so gas yield is reduced in cool seasons (methane production is severely limited in cold climates). Variations incorporating sludge recycling or distributed inflow are referred to as enhanced covered anaerobic ponds.
- Fixed-film digester, usually heated, containing media that increase the surface area available for bacteria to adhere to, thus preventing washout. As more than 90 percent of the bacteria are attached to the media, an HRT of days, rather than weeks, is possible. Separation of fixed solids by settling and screening is necessary to prevent fouling.
- Complete-mix digester sometimes referred to as a continuously stirred tank reactor; usually a circular tank with mixing to prevent solids settling and to maintain contact between bacteria and organic matter. Mixing also maintains a uniform distribution of supplied heat.
- Plug flow digester, usually a long concrete tank where manure with as-excreted consistency is loaded at one end and flows in a plug to the other end. The digester is heated. Although it can have locally mixed zones, it is not mixed longitudinally.

The determination of which digestion technologies are appropriate for a given project depend on the project specific conditions. The majority of the digesters in use in Washington are of the modified plug flow type which includes mixing zones and the introduction of other organic wastes.

Figure 2-1 shows typical process flow diagram provided by the US EPA AgStar Program. The flow diagram is a good representation of the digestion process and includes other uses for energy and byproducts from the AD process.

Figure 2-1: Process Flow Diagram

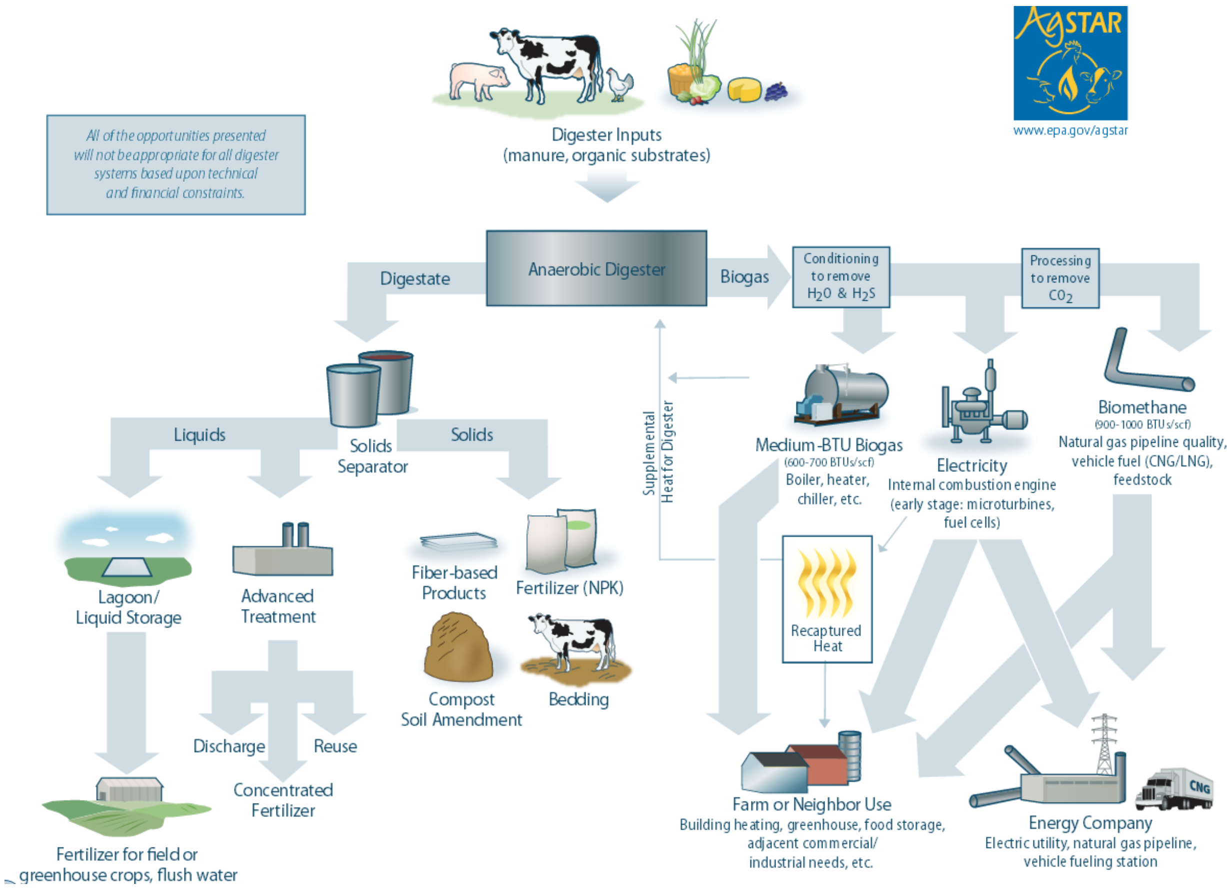
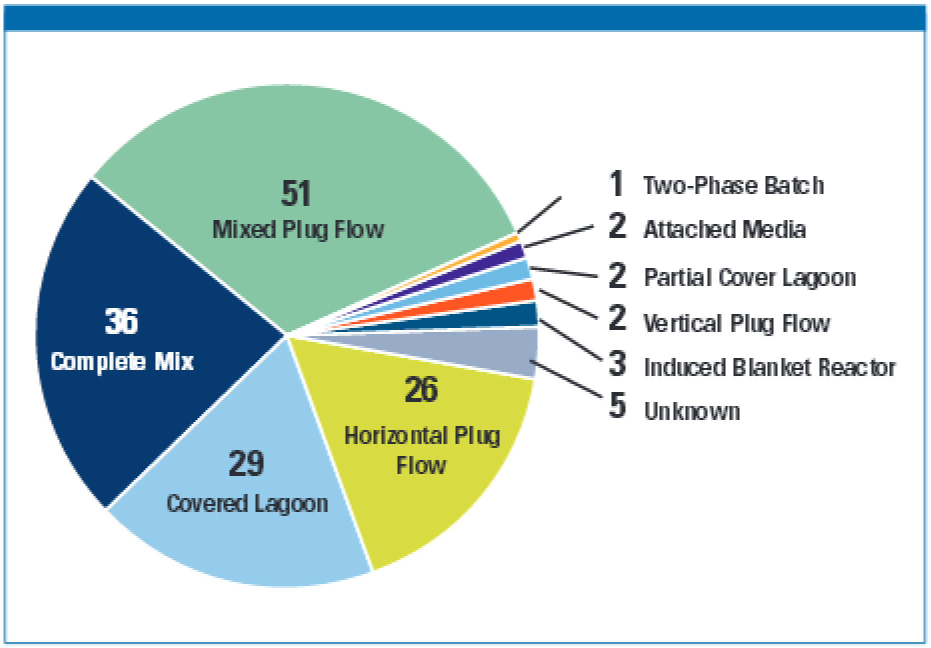


Figure 2-2 shows the relative distribution of digester types in use in the US. The mixed plug flow digester is the predominant technology. The two primary reasons for the popularity of the mixed plug flow digesters are lower capital costs and relative ease of operation. All of the digester technologies would produce a comparable quantity and quality of biogas fuel for generation.

Figure 2-2: Distribution of AD Technology in the US



<u>Manure Management</u>

Manure management practices have an impact on the cost of AD. Dairies use a variety of manure collection and storage methods. The herd management practices also have an impact on the quality and quantity of manure collected and processed. Lactating dairy herd management practices can be classified by two different housing methods.

- Dry Lot – Animals are allowed to loaf in large pens where manure is dropped over a large area and mixed with significant quantities of inert material.
- Free Stall – Animals are confined in free stall barns where manure drops in concrete lanes and is scraped or flushed to collection with small amounts of additional inert material.

Larger dairies also manage replacement herds and depending on the dairy the manure may be collected and included with the lactating herd waste of managed separately through composting. Flush dairies flush the feeding lanes with large quantities of water which dilutes the manure and adds significant volumes of water to the waste necessitating the use of larger digester systems. In all cases the amount and quality of manure collected will vary from dairy to dairy dictating the choice of digestion technology, digester capacity, pre treatment and concentration of manure streams, and sand and grit removal.

<u>Biogas Production</u>

Typical manure digester projects utilize a digester residence time of 20 to 30 days. Each day the manure output from the dairy is fed to the digester and an equal volume of digested manure is discharged for storage and eventual disposal. Many projects also separate the cellulosic fiber and compost that material for sale as a soil amendment or utilize the digested solids as bedding in the barns. In any case the liquid fraction that contains the majority of the nutrients must be discharged. The predominant disposal practice in the US and other parts of the world is land application as fertilizer to cropland.

The biogas production is a biological process whereby complex organic compounds are degraded in two steps by two classes of microorganisms in the digester. In the first step, acidifying bacteria hydrolyze the organic compound into organic acids. In the second step, methanogenic bacteria convert the organic acids into methane and carbon dioxide. A typical composition of biogas from all sources is shown below.

Compound	Formula	%
Methane	CH_4	50–75
Carbon dioxide	CO_2	25–50
Nitrogen	N_2	0–10
Hydrogen	H_2	0–1
Hydrogen sulfide	H_2S	0–3
Oxygen	O_2	0–0

The range of methane content for biogas derived from manure is typically 60 to 65 percent with the carbon dioxide at 35 to 40 percent.

The biogas production is not technology driven. The same total amount of biogas can be produced from any of the digester technologies. There are differences in the rate at which the gas is produced which drives some of the technology decisions. For purposes of this report we assume that regardless of the technology utilized, all of the farms in the Yakima River Valley would produce gas at the maximum potential based solely on the number of animals. This is an appropriate way to consider the maximum electrical potential in the PacifiCorp service territory. The limiting factor would be the actual size of the dairy. Smaller dairies may not have the capital resources to support the high costs to install the gas production and power generation equipment.

Biogas Conditioning

Based on the composition above the biogas should be conditioned prior to use as a combustion fuel to remove the hydrogen sulfide (H_2S). There are a number of cost effective technologies available to remove the H_2S.

- Iron Sponge
- Chemical/Biological External Scrubbers
- Internal Biological Removal in the Digester

In all cases it is desirable to remove the H_2S prior to combustion to reduce the sulfur dioxide emissions in the exhaust and to reduce corrosion in the exhaust components of the engine.

Electrical Power Generation

Systems that generate electricity from biogas consist of:

- an internal combustion engine (compression or spark ignition) or a micro-turbine,
- an optional heat recovery system,
- generator, and
- control system.

Engines and Prime Movers

In Europe it is a popular option to utilize compression ignition (converted diesel) internal combustion engines. Compression engines are also known as dual-fuel engines. A small amount of diesel (10%–20% of the amount needed for diesel operation alone) is mixed with the biogas before combustion. Dual-fuel engines offer an advantage during start-up and downtime as they can run on anywhere from 0 percent to 85 percent biogas.

The majority of the projects in the US utilize spark-ignition internal combustion engines. All of the major gas engine manufacturers supply standard engines rated for use with biogas as the fuel. Typical heat rates for these types of reciprocating engines range from 9,000 to 10,000 Btu/kWh. The online capacity factor for these engines can average 95 percent due to their inherent reliability provided adequate service and maintenance procedures are implemented.

Microturbines are not favored for use with raw biogas due to the dirty composition of the fuel which leads to reliability problems. Larger gas turbines are typically much larger than needed for biogas projects except for those projects that would produce in excess of 5 MW per project. One of the advantages that gas turbines have is a lower NO_x emission profile. For engines that utilize lean burn control technology the NO_x emission rate would range from 0.6 to 1.1 g/bhp-hr.

Heat Recovery Systems

Commercially available heat exchangers can recover heat from the engine water cooling system and exhaust. Typically, heat exchangers will recover around 0.8 kWh of heat per kWh of electrical output from the engine jacket and 0.75 kWh from the exhaust, increasing total (electrical plus thermal) energy efficiency to 65 to 80 percent. The heat is generally used for maintaining the digester temperatures, building heat, and in some cases providing refrigeration for milk cooling.

Generators

Generators typically run in parallel with the utility interconnection and export power in synchronization with the grid. The engine/generator sets are supplied by competent well known manufacturers that package complete systems with reliable controls to manage the power export to the interconnection and grid.

Manure Effluent Management

Digested manure can be further processed to separate fibrous solids for compost or animal bedding. Separation also impacts the distribution of nutrients that must be managed under

Nutrient Management Plans ("NMP"). Phosphorus will be largely distributed in the separated solids while nitrogen will be largely distributed in the liquid. The NMP is a management system that limits the amount of nutrient that can be applied to crop land to that fraction that can be utilized by growing crops. The limits are established to control excess nutrients that migrate to surface water and ground water systems. Digested manure reduces the organic fraction of those nutrients that are not in a form that can be utilized by crops in the current application year. The inorganic forms of nutrients in digested manure is more likely to be utilized by growing crops at the time of application and not accumulate and contaminate water sources. Ultimately manure whether it's digested or not is land applied for disposal.

Emission Control Systems

Typical air emission controls include flares for excess biogas and engines that utilize lean burn carburetion for NO_x and CO control. Permitting for these emissions is a relatively straight forward process with low risk for negative outcomes.

SECTION 3 – POWER PRODUCTION ESTIMATE

Quantifying Energy Potential from Dairies in PacifiCorp's WA State Territory

There are numerous anaerobic digestion ("AD") technologies available, and each technology provider has its own proprietary calculation to determine the potential energy production from a given mass of manure. In order to avoid publishing proprietary data, a method to calculate energy potential was chosen that is based on an industry accepted methodology for calculating the biomethane production from dairy cow manure. It is based on the *U.S. Livestock Project Protocol, Version 4.0* (the "Protocol") published by the Climate Action Reserve and relies heavily on years of research and other calculation protocols, most notably the Intergovernmental Panel on Climate Change Protocol for calculating Greenhouse Gas Emissions from Livestock Waste. The calculations provided in this protocol are derived from internationally accepted methodologies.[2]

Required Parameters for Quantifying Energy Potential

The following parameters are necessary to quantify the energy potential:

Population – P_L

The Protocol differentiates between livestock categories (L) (e.g. lactating dairy cows, dry cows, heifers, etc.). This accounts for differences in methane generation across livestock categories.

Volatile solids – VS_L

The Volatile Solids ("VS") represents the daily organic material in the manure for each livestock category and consists of both biodegradable and non-biodegradable fractions. The VS content of manure is a combination of excreted fecal material and urinary excretions, expressed in a dry matter weight basis (kg/animal).[3]

$Mass_L$

This value is the annual average live weight of the animals, per livestock category. This data is necessary because default VS values are supplied in units of kg/day/1,000 kg mass. Therefore, the average mass of the corresponding livestock category is required in order to convert the units of VS into kg/day/animal. Site specific livestock mass is preferred for all livestock categories. Since site-specific data is unavailable, Typical Animal Mass ("TAM") values were used.

Maximum methane production – $B_{0,L}$

This value represents the maximum methane-producing capacity of the manure, differentiated by livestock category (*L*) and diet. Again, because site specific data is not available, this calculation uses the default B_0 factors supplied as part of the Protocol.

[2] The Reserve's GHG reduction calculation method is derived from the Kyoto Protocol's Clean Development Mechanism (ACM0010 V.5), the EPA's Climate Leaders Program (Manure Offset Protocol, August 2008), and the RGGI Model Rule (January 5, 2007).

[3] IPCC 2006 Guidelines volume 4, chapter 10, p. 10.42.

MS

The MS value estimates the fraction of total manure produced from each livestock category that is collected and delivered the anaerobic digestion system. It is expressed as a percent (%), relative to the total amount of VS produced by the livestock category. Different manure management systems have different MS values. For example, a freestall barn system has an MS value of 0.95, whereas a drylot system has an MS value of 0.60.

Methane conversion factor – MCF

Each anaerobic digestion technology has a volatile solids-to-methane conversion efficiency that represents the degree to which maximum methane production (B0) is achieved and is a function of the temperature and retention time of organic material in the system.[4] This method to calculate methane conversion from VS reflects the performance of the anaerobic digestion system using the van't Hoff-Arrhenius equation, farm-level data on temperature, VS loading rate, and VS retention time.[5]

Methodology

The following summarizes the steps to calculate the potential energy production:

1. Determine total manure produced from the dairies
2. Calculate the volatile solids available in for anaerobic digestion
3. Calculate the conversion of volatile solids to biomethane
4. Calculate the conversion of biomethane to electricity

Step 1: Determine Total Manure Production

Data on cow numbers for specific dairies is not publicly available. However, the Washington Department of Agriculture maintains a database of dairies in the state that have nutrient management plans. This database is publicly available and, while it does not contain specific data on the number of cows at each dairy, it provides a range for the numbers of mature dairy cows and heifers at each dairy. This data was overlaid on the map of PacifiCorp's service territory in Washington State. This results in 60 dairies that are consolidated into eight different size categories based on the number of mature cows on site (see Table 3-1).

[4] IPCC 2006 Guidelines volume 4, chapter 10, p. 10.43.
[5] The method is derived from Mangino et al., "Development of a Methane Conversion Factor to Estimate Emissions from Animal Waste Lagoons" (2001).

Table 3-1: Number of Dairies of Various Sizes	
Mature Cows	**Number of Dairies**
38 to 199	2
200 to 699	15
700 to 1699	22
1700 to 2699	11
2700 to 3699	2
3700 to 4699	4
5700 to 6839	2
6840 and above	2
Total:	60

For each dairy, there is a range of the number of mature cows and heifers. This data was used to derive a range of the daily amount of manure for each dairy. Depending on their size, feed, and lactation status, different types of cows produce varying amounts of manure. The Protocol uses industry accepted values of TAM to estimate the daily manure produce for each livestock category (L) (see Table 3-2).

Table 3-2: Typical Animal Mass for each Livestock Category

Livestock Category (L)	Livestock Typical Animal Mass (TAM) in kg 2006-2008	2009-2010
Dairy cows (on feed)	604[b]	680[c]
Non-milking dairy cows (on feed)	684[a]	684[a]
Heifers (on feed)	476[b]	407[c]
Bulls (grazing)	750[b]	750[c]
Calves (grazing)	118[b]	118[c]
Heifers (grazing)	420[b]	351[c]
Cows (grazing)	533[b]	582.5[c]
Nursery swine	12.5[a]	12.5[a]
Grow/finish swine	70[a]	70[a]
Breeding swine	198[b]	198[c]

Sources for TAM:

[a] American Society of Agricultural Engineers (ASAE) Standards 2005, ASAE D384.2.

[b] Environmental Protection Agency (EPA), Inventory of US GHG Emissions and Sinks 1990-2006 (2007), Annex 3, Table A-161, pg. A-195.

[c] Environmental Protection Agency (EPA), Inventory of US GHG Emissions and Sinks 1990-2010 (2012), Annex 3, Table A-191, pg. A-246.

Step 2: Calculate the Volatile Solids Available for Digestion

Consistent with the Protocol, appropriate VS_L values for dairy livestock categories were obtained from the state-specific lookup tables available through the Climate Action Reserve. The VS_L values for lactating cows, mature dry cows, and heifers are shown in Table 3-3.

Table 3-3: Daily Volatile Solids Production for each Livestock Category	
Livestock Category (L)	**VS_L (kg/day/1000 kg mass)**
Dairy cows	11.50[a]
Non-milking dairy cows	11.50[a]
Heifers	8.43[a]
Bulls (grazing)	6.04[b]
Calves (grazing)	6.41[b]
Heifers (grazing)	8.25[a]
Cows (grazing)	7.82[a]
Nursery swine	8.89[b]
Grow/finish swine	5.36[b]
Breeding swine	2.71[b]

[a] Environmental Protection Agency (EPA) - U.S Inventory of Greenhouse Gas Sources and Sinks, 1990-2012 (2013), Annex 3, Table A-204.

[b] Environmental Protection Agency (EPA) – Climate Leaders Draft Manure Offset Protocol, October 2006, Table IIa: Animal Waste Characteristics , p. 18.

In order to arrive at VS_L in the appropriate units (kg/animal/day), Equation 3.1 is used:

$$VS_L = VS_{Table} \times Mass_L/1{,}000 \qquad \textit{(Equation 3.1)}$$

Where:

VS_L = Volatile solid excretion on a dry matter weight basis, *kg/animal/day*

VS_{Table} = Volatile solid excretion from Climate Action Reserve lookup table, from Table 3, *kg/day/1000kg*

$Mass_L$ = Average live weight for livestock category *L* from Table 2 , *kg*

The VS_L is then converted into the monthly amount of VS available from each dairy by applying the population and manure management factors arrived at previously, using Equation 3.2. Because the dairies in the study area predominately utilize drylot manure management systems, the MS_L for all livestock categories is 0.60, meaning that 60 percent of the total manure produced is collected and could be delivered to an AD system.

$$\boldsymbol{VS_{avail,\,L} = (VS_L \times P_L \times MS_L \times days_{mo})} \qquad \textit{(Equation 3.2)}$$

Where:

$VS_{avail,\,L}$	=	Monthly volatile solids available for the anaerobic digestion system by livestock category *L, kg dry matter*
VS_L	=	Volatile solids produced by livestock category *L* on a dry matter basis, *kg/animal/day*
P_L	=	Average population of livestock category *L*
MS_L	=	Percent of manure produced by each livestock category *L*, that is collected in the manure management system and delivered to the AD system, *%*
$days_{mo}$	=	Calendar days per month, *days*

Step 3: Calculate the Conversion of Volatile Solids to Biomethane

Now that the VS that are delivered to the AD system are known, the amount of methane that can be generated from those VS via anaerobic processes must be calculated. This is accomplished by multiplying the $B_{0,L}$, the maximum methane capacity for each livestock category, by VS_{deg}, the amount of the VS delivered to the AD system (calculated in Equation 3.2) that is degraded and converted to methane (see Equation 3.3). The $B_{0,L}$ for each livestock category is derived from empirical data (see Table 3-4). The VS_{deg} is a function of the total VS_{avail} and the '*f*' factor, which incorporates the van't Hoff-Arrhenius equation described previously.

$$\boldsymbol{BE_{CH4,\,L} = (VS_{deg,\,L} \times B_{0,L} \times days_{mo})} \qquad \textit{(Equation 3.3)}$$

Where:

$BE_{CH4,\,L}$	=	Total monthly baseline methane emissions from anaerobic manure storage/treatment system *AS* from livestock category *L*, m^3 CH_4*/mo*
$VS_{deg,\,L}$	=	Monthly volatile solids degraded in AD system for livestock category *L*, *kg dry matter*
$B_{0,L}$	=	Maximum methane producing capacity of manure for livestock category *L* – see Table 4 for default values, m^3CH_4*/kg of VS*
$days_{mo}$	=	Calendar days per month, *days*

Table 3-4: Maximum Methane Production for each Livestock Category

Livestock Category (L)	$B_{0,L}$[a] (m^3 CH_4/kg VS added)
Dairy cows	0.24
Non-milking dairy cows	0.24
Heifers	0.17
Bulls (grazing)	0.17
Calves (grazing)	0.17
Heifers (grazing)	0.17
Cows (grazing)	0.17
Nursery swine	0.48
Grow/finish swine	0.48
Breeding swine	0.35

[a] Environmental Protection Agency (EPA) – Climate Leaders Draft Manure Offset Protocol, October 2006, Table IIa: Animal Waste Characteristics , p. 18.

$$VS_{deg,\,L} = \sum_L (VS_{avail,\,L} \times f) \qquad \textit{(Equation 3.4)}$$

Where:

$VS_{deg,\,L}$	=	Monthly volatile solids degraded by AD system by livestock category *L*, *kg dry matter*
$VS_{avail,\,L}$	=	Monthly volatile solids available for degradation AD system by livestock category *L*, *kg dry matter*
f	=	The van't Hoff-Arrhenius factor = "the proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system"[6]

The '*f*' factor (see Equation 3.5) converts total available volatile solids in the AD system to methane-convertible volatile solids, based on the monthly temperature of the AD system. For heated AD systems that operate at either mesophilic (35–40°C) or thermophilic (50–60°C) temperatures, the '*f*' factor is at the maximum value of 0.95. The '*f*' factor comes into play only for AD systems that are significantly influenced by ambient temperatures (e.g. covered lagoons). It is assumed that the AD systems that are being contemplated in the study area are either mesophilic or thermophilic. Thus, the '*f*' factor is 0.95.

[6] Mangino, et al.

$f = exp[E(T_{mo} - T_{ref})/(R \times T_{ref} \times T_{mo})]$ **(Equation 3.5)**

Where:

f	=	The van't Hoff-Arrhenius factor
E	=	Activation energy constant (15,175), *cal/mol*
T_{mo}	=	Monthly average AD system temperature (K = °C + 273). If T_{mo} < 5°C then *f* = 0.104. If T_{mo} > 29.5°C then *f* = 0.95, *Kelvin*
T_{ref}	=	303.16; Reference temperature for calculation, *Kelvin*
R	=	Ideal gas constant (1.987), *cal/Kmol*

The result of Equation 3.3 is the volume (in m^3) of biomethane per month from each dairy that results in the collection delivery and anaerobic digestion of the manure-derived volatile solids.

Step 4: Calculate the Conversion of Biomethane to Electricity

For the volumes of biomethane that can be generated via the AD systems that are being considered for the dairies in the study area, the most appropriate biomethane-to-electricity conversion technology is a reciprocating engine-generator. While the electrical conversion efficiencies of reciprocating engine-generators generally increase in size, they vary by manufacturer. Therefore, rather than attempting to predict a conversion efficiency for each size of dairy, a first approximation of 37.5 percent was used as an electrical conversion efficiency for each size of AD system. This was used to calculate the electrical power production for each dairy, based on its calculated volume of biomethane.

In addition, to arrive at the annual electrical energy production, it was assumed that each engine-genset was operating at the equivalent of full capacity for 90 percent of the hours each year.

Results

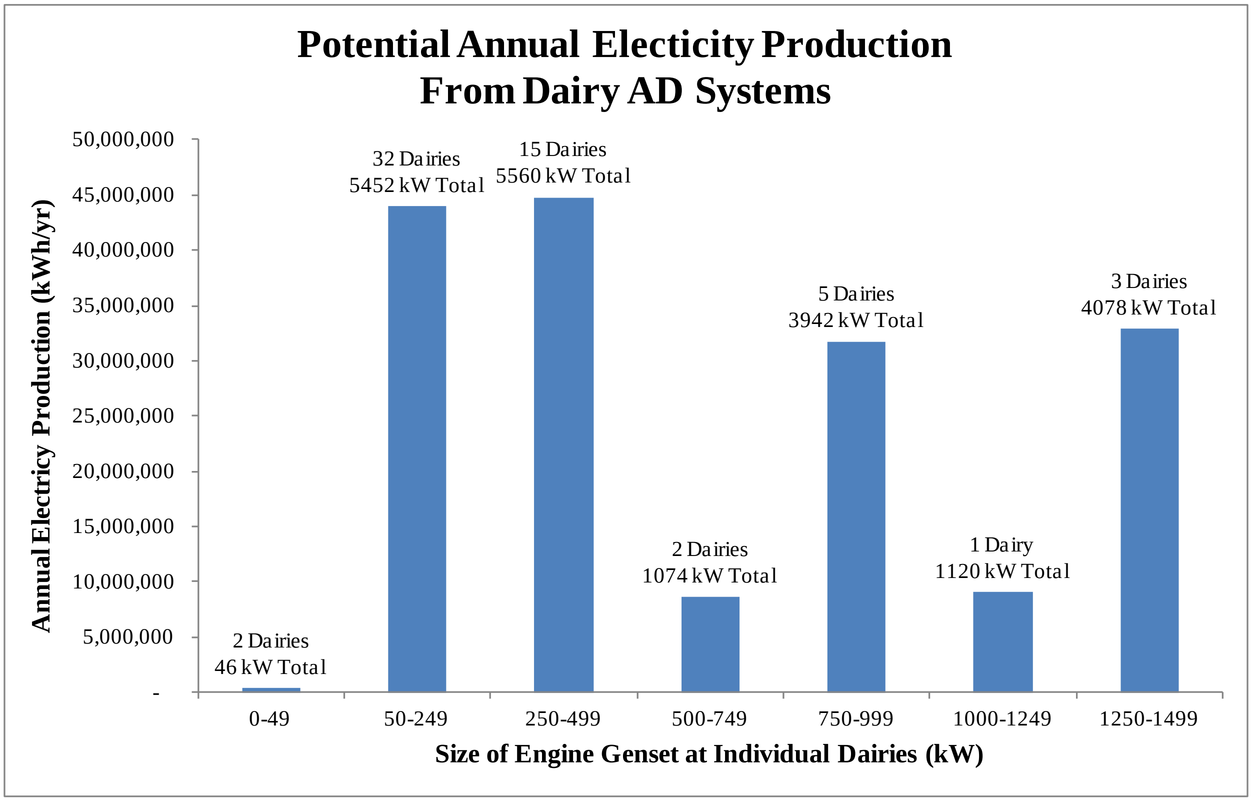
Based on the dairy data provided by the Washington Department of Agriculture and the methodology described above, Table 3-5 summarizes the potential electrical power production from the dairies. If all of the dairies installed anaerobic digesters, the total installed power would range from approximately 16.0 MW to 26.6 MW. The annual energy production would range from approximately 129 GWh/yr to 214 GWh/yr. These ranges are based on the range of dairy sizes.

Table 3-5: Electrical Power Production Ranges by Dairy Size

Mature Cows	Number of Dairies	Minimum Power (kW)	Maximum Power (kW)	Average Power (kW)
38 to 199	2	8	38	23
200 to 699	15	47	151	99
700 to 1699	22	143	248	246
1700 to 2699	11	322	520	421
2700 to 3699	2	576	779	677
3700 to 4699	4	679	894	787
5700 to 6839	2	1,102	1,345	1,221
6840 and above	2	1,242	1,509	1,375
Total:	60	15,971	26,576	21,273

Because the economics of installing digesters on smaller dairies may not be favorable, another useful way to view the potential is by grouping the engine-gensets by size. Figure 3-1 summarizes this information, based on the average number of mature dairy cows within each of the dairy size categories. If the size of the AD systems were limited to 500 kW and larger, there are 11 potential projects that would total approximately 10.2 MW and produce approximately 82 GWh/yr.

Figure 3-1: Potential Annual Electricity Production from Dairy AD Systems



SECTION 4 – ENVIRONMENTAL AND REGULATORY

The State of Washington has a well developed and straight forward permit program that specifically addresses anaerobic digester development. The following paragraphs briefly describe the various permit programs.[7]

WA Solid Waste Permitting

AD systems that contain at least 50 percent manure and no more than 30 percent other organic waste may operate under an exemption from solid waste handling permits. Systems not subject to the exemptions must obtain a solid waste handling permit.

WA Water Permitting

AD systems operating at permitted CAFOs do not need an additional permit if the system is digesting only manure.

Water quality permits are required for discharges to surface and ground water (RCW 90.48.160). Operators, including digesters and participating dairies, must manage their operations to ensure that they do not discharge to surface or ground water. When discharge is unavoidable, water quality permits are required prior to any discharge.

Anaerobic digesters located on licensed dairies need to be covered under the dairy's nutrient management plan (Chapter 90.64 RCW). The Dairy Nutrient Management Act ("NMA") requires all licensed dairies to develop, update, and implement NMP's, register with WSDA, allow regular inspections, and keep records verifying that the NMP is being followed. These records can also show that discharges are not occurring, thus avoiding the need for water quality permits.

WA Air Permitting

New or modified sources of air pollution in the state of Washington require an air permit prior to beginning construction and operation (Clean Air Act, Chapter 70.94 RCW; New Source Review WAC 173-400-110). Air permits (Notice of Construction or Orders of Approval) regulate criteria pollutants such as particulate matter, sulfur dioxide, and nitrogen oxides, and also toxic air pollutants such as ammonia and hydrogen sulfide

Local Jurisdiction Permitting

Local or county planning agency requirements for the planned anaerobic digesters must be satisfied. Requirements may include permit approvals for building, grading, water systems, shorelines, right-of-way, utilities, site plans, septic systems, floodplains, zoning, and others.

The State Environmental Policy Act (SEPA) may require review of the environmental impacts of the planned digester by a local or state agency (Chapter 43.21C RCW). State policy requires state and local agencies to consider the likely environmental consequences of the decisions they make, including decisions to approve or deny license applications or permit proposals.

[7] Washington State University Fact Sheet FS040E

REC Qualification

With the passage of Initiative 937 in 2006 the State of Washington passed a renewable energy standard that applies to PacifiCorp. The Renewable Portfolio Standard calls for electric utilities that serve more than 25,000 customers to obtain 15 percent of their power from renewable sources by the year 2020. Between January 1, 2012 through December 31, 2015 at least 3 percent of PacifiCorp's load must be supplied by renewable sources. For the period January 1, 2016 through December 31, 2019 the percentage increases to 9 percent. The increase to 15 percent must be met by January 1, 2020. For purposes of the standard anaerobic digesters qualify as renewable sources. Energy from renewable sources is eligible for compliance if the facility began operations after March 31, 1999. The facility must be located in the Pacific Northwest as defined by the Bonneville Power Administration.

All of the generation that could be produced from AD projects with dairies in the Yakima County service territory would generate REC's that could be registered and traded. The Western Renewable Energy Generation Information System ("WREGIS") is an independent renewable energy tracking system for the region covered by the Western Electricity Coordinating Council ("WECC"). REC's can be registered with WREGIS and traded within the WECC states. It is beyond the scope of this assessment to establish the market value of REC's traded within the region.

Other Investment Incentives

Investment Tax Credit

The federal business energy investment tax credit is available for CHP projects. The credit is equal to 10 percent of expenditures, with no maximum limit stated. Eligible CHP property generally includes systems up to 50 MW in capacity that exceeds 60 percent energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90 percent of the system's energy source, but the credit may be reduced for less-efficient systems. This credit applies to eligible property placed in service after October 3, 2008.

Production Tax Credit

The federal electricity production tax credit has expired and is no longer available.

Washington Renewable Energy Cost Recovery Incentive Payment Program

In May 2005, Washington enacted Senate Bill 5101, establishing production incentives for individuals, businesses, and local governments that generate electricity from solar power, wind power or anaerobic digesters. The incentive amount paid to the producer starts at a base rate of $0.15 per kilowatt-hour ("kWh") and is adjusted by multiplying the incentive by the following factors:

- For electricity produced using solar modules manufactured in Washington State: 2.4.
- For electricity produced using a solar or wind generator equipped with an inverter manufactured in Washington State: 1.2.
- For electricity produced using an anaerobic digester, by other solar equipment, or using a wind generator equipped with blades manufactured in Washington State: 1.0.

- For all other electricity produced by wind: 0.8.

These multipliers result in production incentives ranging from $0.12 to $0.54/kWh, capped at $5,000 per year. Ownership of the renewable-energy credits ("RECs") associated with generation remains with the customer-generator and does not transfer to the state or utility.

Washington Energy Sales and Use Tax Exemption

In Washington State, there is a 75 percent exemption from tax for the sales of equipment used to generate electricity using fuel cells, wind, sun, biomass energy, tidal or wave energy, geothermal, anaerobic digestion or landfill gas. The tax exemption applies to labor and services related to the installation of the equipment, as well as to the sale of equipment and machinery. Eligible systems are those with a generating capacity of at least 1 kilowatt (kW). Purchasers of the systems listed above may claim an exemption in the form of a remittance. Originally scheduled to expire on June 30, 2013, the exemption has been extended through January 1, 2020.

Greenhouse Gas Reduction

According to the USEPA, methane is a greenhouse gas that is approximately 21 times more effective in trapping heat in the atmosphere than carbon dioxide over a 100-year period. Anthropogenic sources of methane include landfills, natural gas and petroleum systems, agricultural activities, coal mining, stationary and mobile combustion, wastewater treatment, and certain industrial processes. Methane emissions generated by the manure management practices of large dairy operations have been identified as a significant source of GHGs. The US EPA is required to regulate GHG emissions under the broad provisions and authorities of the Clean Air Act. Therefore, reducing GHG emissions has become important and a potential source of revenue on some dairies. Anaerobic digesters can provide a means for dairy farms to participate in markets for GHG avoidance and sequestration.

Anaerobic digestion is a waste stabilization process. Stabilization occurs by the microbially mediated decomposition of the carbon in complex organic compounds to methane and carbon dioxide. This natural process takes place in the manure storage lagoons that exist at most large dairies and results in the generation of biogas, which is made up of approximately 2/3 methane and 1/3 carbon dioxide. Because this process takes place in controlled conditions in an engineered AD system, such a system provides the opportunity to capture and combust the biogas it produces. It is the capture and combustion of this biogas, along with the ability to maximize the degree of waste stabilization that differentiates anaerobic digestion in an AD system from anaerobic decomposition, which occurs naturally in lagoons and other livestock manure storage structures.

The total amount of GHG credits produced from an AD system can be calculated using a protocol published by the Climate Action Reserve and accepted by programs that value and trade the credits. The protocol calculates the net GHG emissions reductions from digestion, subtracting post-digester installation GHG emissions to those that would be emitted without digestion. In order to sell credits, a project must have these reductions certified by a third party registry. According to the Climate Trust, a third party that certifies such credits, a typical project in the Pacific Northwest that incorporates an on-farm AD system will generate 2.5 to 3.5 credits per mature cow equivalent each year.[8] Using the average of the two values and the range of animals described in Section 3, if all of the dairies that could produce more than 500 kW developed AD systems, they would avoid 164,000 to 230,000 tonnes of CO_2e emissions per year.

[8] Weisberg, Peter. Environmental Market Revenue Opportunities for Biogas Projects. NEBC NW Biogas Workshop, Portland, OR, April 27, 2012.

SECTION 5 – DEVELOPMENT COST

Completed Major Equipment Revisions

The capital requirements to install a digester will vary widely depending on digester design chosen, size, and choice of equipment for utilization of the biogas. In 2009 the US EPA AgSTAR program analyzed the investment at 19 dairy projects that installed plug flow digester similar the digesters in use in Washington. The analysis of investments made versus herd size at 19 dairy farm plug-flow digesters yielded an estimate of $566,006 + $617 per cow in 2009 dollars. The estimates provided in this assessment have been normalized to 2014 dollars using an inflation rate of 1.5 percent per year. Ancillary items that may be incurred are charges for connecting to the utility grid and equipment to remove hydrogen sulfide, which could add up to 20 percent to the base amount. There is considerable interest in digester designs that are economically feasible for smaller farms, but some digester components are difficult to scale down. A complete mix digester with separator installed on a 160-cow Minnesota dairy farm in 2008 cost $460,000, or $2,875/cow. Another way to consider the investment is to assume a unit cost per kilowatt of installed capacity to be $3000 to $3500. Smaller farms would not likely invest the capital to install digesters for power production. Figure 5-1 below shows the total value of the potential capital investment if all of the farms in a given generation capacity were developed based on the AgStar estimated cost. Figure 5-2 shows the individual farm investment based on the generation capacity. The total capital investment estimate that would be required to develop 100 percent of the resources would be approximately $91MM. It is not practical to assume that all projects rise to the level of investment quality. May of the smaller farms would not be practical. We have included the capital investment shown for each generator capacity in Figure 5-2.

Figure 5-1: Total Capital Investment

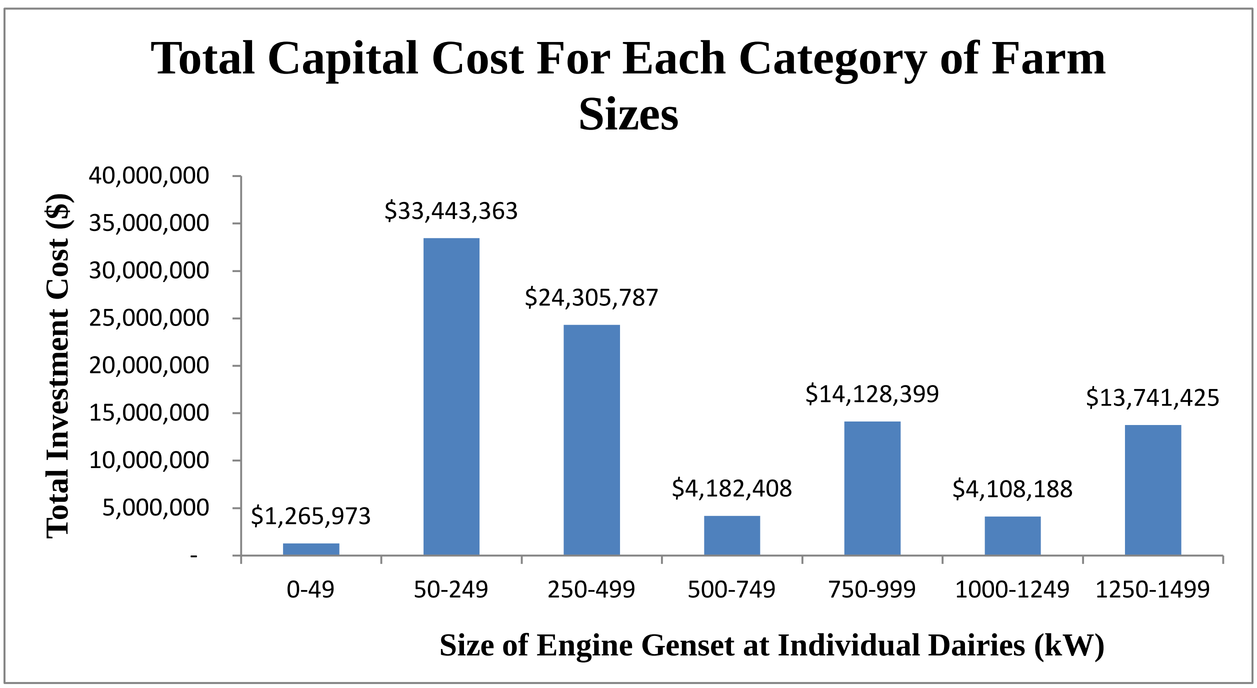
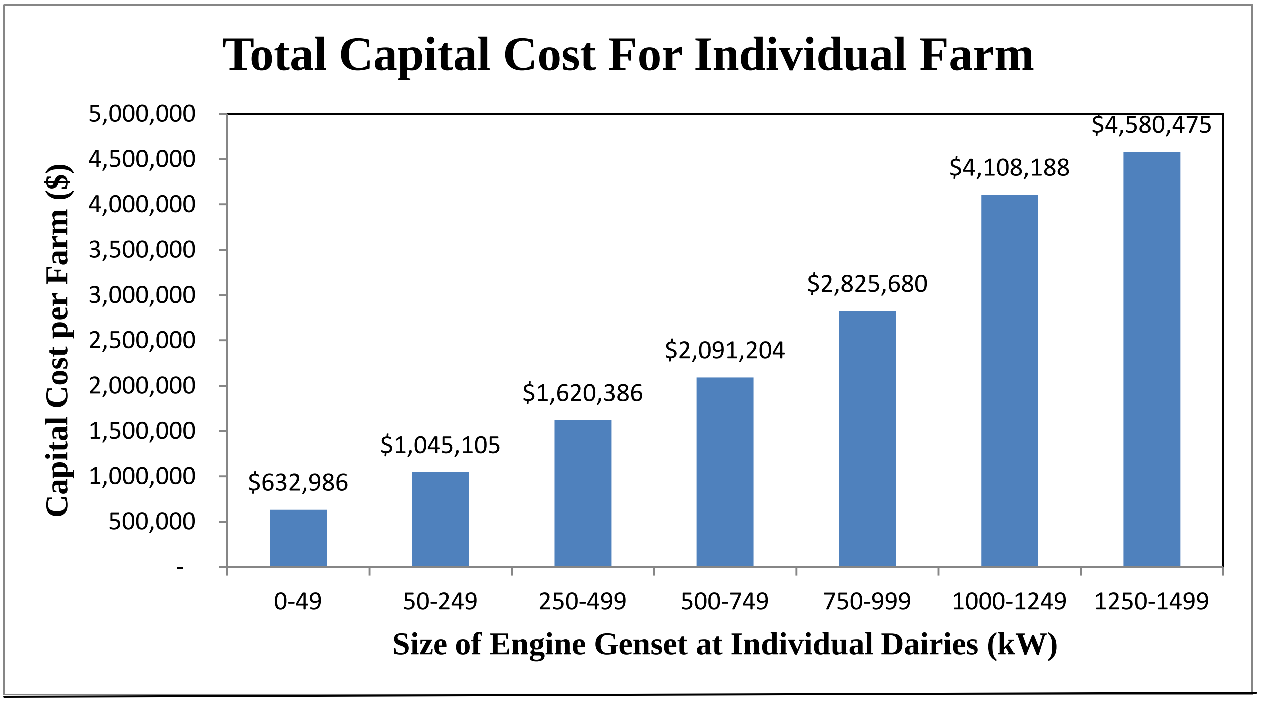


Figure 5-2: Total Investment on an Individual Farm at Various Generation Capacities



SECTION 6 – OPERATING COSTS

The USDA Natural Resources Conservation Service has been heavily involved in developing the federal design and operation standards for the design and installation of farm based digesters. Much of the work and information published by the AgStar program referenced NRCS Practice Standards. The following operating cost information is based on an analysis done by the NRCS.[9]

Table 6-1: USDA NRCS Operating Cost Analysis

Electricity production costs for AD case studies with reported biogas production

Manure AD system type by species	$/GJ	$ per kWh	No. of systems	$/GJ O&M	$ per 1000 kWh O&M
Mixed—Swine	20.11	0.07	2	0.80	2.90
AD covered anaerobic lagoon—Swine	25.62	0.09	5	2.09	7.57
Plug flow—Dairy	25.78	0.09	9	2.69	9.74
Electricity	**25.88**			–	–
AD—Other swine	27.16	0.10	1	1.61	5.82
Mixed—Dairy	52.39	0.19	4	3.54	12.79
AD—Other dairy	79.33	0.29	1	12.07	43.64

* Average U.S. retail costs taken from DOE

* A thermal efficiency of 30 percent was assumed for biogas to electrical energy conversion.

Based on the data from the NRCS analysis and keeping with the plug flow digester design it is shown that the operating costs with electrical production are $0.09/kWh. The cost analysis is based on the operating results of nine different projects. It is not reported in the discussion how large the systems are or what the basis of the fixed and variable expenses are. It should be expected that fixed operating costs would be lower based on economies of scale for larger digester projects.

Addition of Other Organic Wastes

It has been accepted in the dairy based digester industry that using the electrical power internally and offsetting retail electricity rates with the generator output can yield better economic performance than the sale of power at wholesale rates. Including the various incentives does not normally lead to profitable commercial operations generally. The use of additional organic can boost the gas production by as much as 300 percent with very minimal increases in capital and operating costs. This would have a direct impact on the performance of the system and lower the O&M costs accordingly. Unfortunately the proximity to significant quantities of those additives is limited due to the location in Yakima County.

[9] "An Analysis of Energy Production Costs from Anaerobic Digestion systems on US Livestock Production Facilities" USDA NRCS, October 2007

George DeRuyter & Sons Dairy

The George DeRuyter Dairy is located within the Yakima County service territory. It is the only dairy in the service territory to have installed a commercial digester and an excellent example of the implementation of the technology and profitability challenges associated with electrical sales as the only source of cash flow. Appendix 1 to this report includes a feasibility report prepared for the Washington State Department of Commerce outlining the economic and environmental challenges facing the development of AD projects in the state.[10]

The report provides an analysis of the development challenges and profitability of a dairy based digester in the Yakima Valley. The report is significant due to the fact that it is based on one of the largest dairies in the State of Washington where economies of scale can have a positive impact on the development cost and output. The report also has analysis of the cash flow impacts of utilizing electrical sales based on the Washington State Schedule 37 avoided cost rates for Qualifying Facilities as the only source of income. The lack of success in developing projects in the service territory is characterized as follows.

- Projects based entirely on revenue streams from Power Purchase Agreements at the Qualifying Facility rate structure are not likely to have commercial success. This is a situation that is a factor elsewhere throughout the U.S with Pacific Northwest electrical prices only exacerbating the problem for the region, especially in the Yakima River Basin, which has some of the lowest rates in the nation.
- Presence of the dairies in an area away from urban centers which negatively impacts a project's ability to secure off-farm co-digestion substrates with or without tipping fees. In the northwest area of the state projects are more likely able to source additional substrates and organic wastes that contribute to gas production and revenue from both energy sales and tipping fees
- Declining Renewable Energy Credits (RECs) for electrical power production has reduced the value of these credits, especially in the Pacific Northwest, where a multitude of wind projects and reduced demand have flooded the renewable power market.
- Success rates for development projects could be improved with a move toward Renewable Natural Gas sales rather than dependence on revenue from electricity sales.

[10] "An Anaerobic Digester Case Study Alternative Offtake Markets and Remediation of Nutrient Loading Concerns Within the Region" Washington State Department of Commerce

APPENDIX 1

RENEWABLE NATURAL GAS AND NUTRIENT RECOVERY FEASIBILITY FOR DERUYTER DAIRY

AN ANAEROBIC DIGESTER CASE STUDY FOR ALTERNATIVE OFFTAKE MARKETS AND REMEDIATION OF NUTRIENT LOADING CONCERNS WITHIN THE REGION

A REPORT TO WASHINGTON STATE DEPARTMENT OF COMMERCE

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- Washington State University Energy Program, specifically Jim Jensen and Erin Kanoa
- Promus Energy, led by Dan Evans, including Promus partner Gary Coppedge, Heather Kurtz, Brandon Coppedge, and Kathy and Blair Scanlan of Scanlan Consulting
- The Climate Trust, led by Peter Weisberg

Particular agencies/industry contacts that were instrumental to report development include:

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Chapter One — Introduction and Highlights

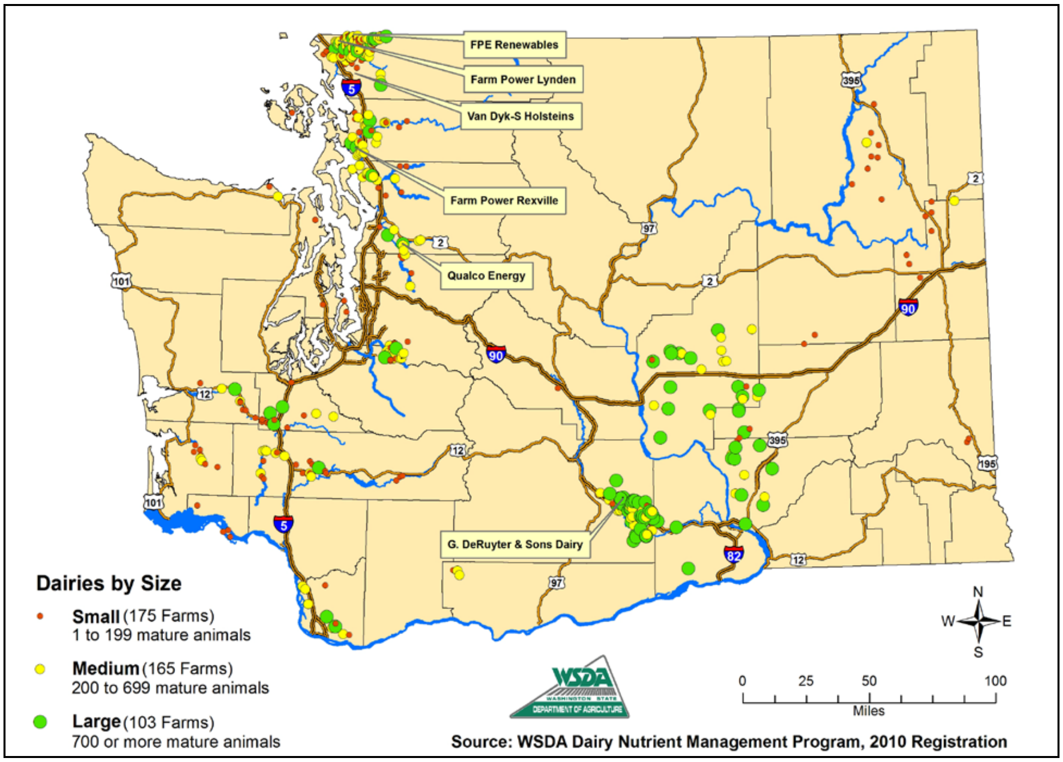
Introduction

Washington State has 443 commercial dairy farms, totaling more than 250,000 dairy cows. Roughly 100 of these dairies, or 23 percent of the total, can be considered large production facilities comprising 700 or more mature animals. Whatcom County in the upper northwest corner of the state and the Columbia Basin in the central region of the state are the two primary dairy centers, totaling nearly 50,000 and 100,000 dairy cows, respectively, with more than 70% of these large dairies located in the Basin (WSDA, 2011). Thanks to commercial developmental support, both in the form of loan/grant opportunities (USDA Rural Development) and industry sponsorship (EPA AGSTAR), U.S. farms, particularly dairies, began to show, during 1990-2000, increased interest in and installation of emerging anaerobic digestion (AD) technology—technology that had previously been mostly exclusive to either municipal wastewater or European agriculture sectors.

Due to historically low received electrical sale prices, Washington State and the entire Pacific Northwest (PNW) were late in this development cycle, only installing its first digester in 2004 near Lynden, Washington in Whatcom County. Recognizing the unique hurdles present within the PNW for development of such projects, Washington State University (WSU) in collaboration with state agencies (Washington State departments of Agriculture, Commerce, Ecology as well as Office of the Governor) spearheaded targeted research and extension for production of value-added co-products from AD, i.e. fiber, recovered nutrients, and co-digestion. In fact, primary funding for this research/extension thrust area (Paul Allen Family Foundation via the Climate Friendly Farming Project; www.csanr.wsu.edu) leveraged some grant dollars to assist in development of that first Lynden digester as well as continued use of its facilities as an academic/industry test bed for emergent technology.

Outputs from over a decade of research, extension, and industrial/government collaboration has led to technological and market breakthroughs in value-added co-product development (patented processes for production of a peat moss substitute, struvite, organic phosphorus-containing fine manure solids, and bio-ammonium sulfate) as well as a significant increase in the number of working, farm-based digesters in the state and region. Figure 1.1 is a recent map detailing the Washington State dairy sector and the six present AD projects. A seventh project, Rainier Biogas, near Enumclaw, Washington, is expected to start operating in late summer 2012.

Figure 1.1: Washington State dairies and anaerobic digester installations (WSDA 2011)



Notably, of these AD dairy projects, six are in the upper northwest corner within Whatcom, Skagit and King counties, with only one facility in the Columbia Basin — the George DeRuyter and Sons digester near Outlook, Washington, built in 2006. While the state and industry are proud of the success in the upper region, there continues to be concern regarding the lack of progress in the Basin. Several factors have been identified for this lack of success, each unfortunately, with little near-term opportunity for resolution. The three key factors include:

1. Presence within the service territory of Pacific Power region, which has been less responsive to AD project development than Puget Sound Energy within the upper west region, in regard to project development and pricing and structure of power purchase agreements. This is a situation seen elsewhere throughout the U.S. with EPA AGSTAR noting that relationships/interest of utilities is a key burden to widening adoption of farm-based AD (US-EPA, 2010) — with PNW electrical prices only exacerbating the problem for the region, especially in the Columbia Basin, which has some of the lowest rates in the nation.
2. Presence on the east side of the state, away from urban centers which negatively impacts a project's ability to secure off-farm co-digestion substrates with or without tipping fees—a business model that has shown great success on the upper west side (Frear et al, 2011; Bishop and Shumway, 2009).

3. Declining Renewable Energy Credits (RECs) for electrical power production has reduced the value of these credits, especially in the Pacific NW, where a multitude of wind projects and reduced demand have flooded the renewable power market.

With no additional AD construction within the Basin since 2006, continued non-viability of existing business plan approaches to new project development within the Basin, and emerging, near-term concerns regarding the long-term viability of the DeRuyter project, a feasibility project was authorized and funded by the Washington State Department of Commerce. Specifically, the study was to address three issues:

1. Generation of a baseline DeRuyter economic model, which assesses the existing site, and potentially the Basin as a whole, in regard to sustained AD development.
2. Development of a detailed techno-economic analysis offering a new business model approach for the site, and potentially the region, focused not on electric production and sales but renewable natural gas (RNG) production and sales, with discussion of opportunities and hurdles -- the assumption being that continued up-stream struggles against pejorative electrical sale prices and utility involvement require a completely new model, especially given emerging technology and pricing options related to RNG.
3. Parallel development of techno-economic evaluations of nutrient recovery technology insertion into a RNG model as the Basin is presently under concerns related to important environmental impacts, specifically: (1) phosphorus loading and eutrophication of waterways (US-EPA, 1996); (2) nitrate penetration within municipal water systems and its effects on human, particularly infant health (US-EPA, 2010); and (3) PM 2.5 loading via ammonia/dust release and its impact on air quality and human health (Koenig et al, 2005).

While the project is site specific, focusing on techno-economic details for an existing and retrofitted DeRuyter project, it is anticipated that outputs can be applied to potential project development Basin-wide, via distributed, semi-distributed or centralized approaches.

HIGHLIGHTS/KEY FINDINGS

While the ensuing chapters detail the assumptions and findings of the project and its three main objectives, this section summarizes key findings from the body of the report. As with the earlier identified objectives, the summary will be divided into three sections: (1) present techno-economic reality for the DeRuyter Dairy and its combined heat and power (CHP) AD operation; (2) potential of alternative business plans associated with conversion of combined heat and power production to RNG, both in regard to technical approach and markets; and (3) assessment of potential inclusion of nutrient recovery technology within the RNG platform, again both from a technical and market view.

Baseline CHP

The first important conclusion drawn from the economic analysis of the baseline CHP project is that the DeRuyter AD project has a pre-tax, positive cash balance — one that continues and slightly grows with time, despite reductions in received electrical prices. This cash flow is thanks in great extent to the value-added products coming off the back end of the digestion process — the fiber for RePeet™ production and the phosphorus-rich fine solids. Presently these two products combine to represent 38% of the project revenue, but in 2013, with the reduced electrical sales prices, they total 54%, and ultimately near the end of the Pro Forma they will near 65% of total revenue. Credit is due to the DeRuyter dairy as well as to partnering industries associated with the fiber and nutrient markets, as it is only through development of these value-added products that the project is able to stay cash positive. From a regional perspective, continued development and growth of these two product markets could conceivably allow for deployment of a new farm-based AD model that compensates for particularly low electrical prices within the Columbia Basin. Application of this model, though, will still be strongly influenced by even small to moderate elevations in received electrical prices, capital debt structures for the AD projects, and maturity and growth potential for the co-product markets.

Non-RNG Modifications to the Baseline CHP

The analyses showed that present and future cash flow of the CHP model could be improved by the addition of substrate that produces additional biogas and by additional generator capacity (new or used). While not a marked improvement, especially in the first years, enhanced biogas production from substrates combined with an additional *used* engine/generator set leads to roughly 30% increase in cash flow as compared to the existing non-substrate baseline. This potential cash benefit could be offset by concerns of the increased loading of nutrients that might occur due to substrate intake and digestion. Importantly, investment in such a plan (debt structure on the additional engine prices at approximately $1.1 million) only makes sense if at first it becomes clear that 20-30% substrate addition is achievable on a consistent and reliable basis while not adversely affecting the nutrient management plan for the farm and the region. Of equal importance is that the type and volume of substrates received not adversely affect the valuable downstream processes for production of fiber and nutrient-rich solids.

RNG Markets and Off-Takes

Development of the RNG model at DeRuyter and across the Basin requires the installation of RNG infrastructure and long-term off-take agreements and credits that generate attractive net cash flow scenarios. Identified challenges to the RNG model reside strongly on the high capital cost of RNG infrastructure, particularly facilities and equipment related to RNG distribution (pipelines and/or tube trailers); pipeline injection point/meter stations; and RNG/CNG fueling stations that set the stage for widespread RNG production and use. While DeRuyter and/or third-party equity partners can conceivably handle the debt load associated with installation of biogas purification and compression equipment on the farm under most scenarios, it is the additional, intensive capital costs associated with the off-farm, 'to the market' infrastructure that becomes particularly problematic to project development if the associated cost and risk is borne by a single RNG producer. Additional risk and uncertainty resides in environmental credits associated with RNG production and use – namely, Renewable Identification Numbers or RINs, which currently can add the equivalent of more than $1.00 per GGE. However, the primary need in establishing the viability of the RNG model is the securing of high-value, long-term agreements with end users with the primary impediment to this occurring residing in the 'to the market' associated capital costs.

RNG Model

The RNG model offers strong opportunities, especially if the above capital expenditure issues could be mitigated by private/public partnership. Two important RNG supporting factors delineated by the team include:

- Use of RNG within an AD-based "integrated systems approach" producing multiple revenues such as renewable fuel, nutrients, fiber products (compost and peat moss substitute), CO_2, and other "by-products;"
- The rise in the cost of petroleum, the growing availability of CNG and natural gas vehicles and conversions for popular heavy-duty truck engines, and the resulting national shift to methane fuels in the high-value transportation fuels market;

RNG was evaluated under three pricing scenarios (commodity, commodity plus RIN, and Retail Fast Fuel Sales) and compared to the current and 2 MW substrate CHP models.

1. Commodity natural gas pricing: Even if sold at low wholesale prices for pipeline gas ($3.87/MMBTU or $0.44/GGE), RNG approximates but is slightly below (~$200-300K) the CHP model in cash flow.
2. Commodity plus "green premium" (RIN): When renewable credits are added to the commodity price of gas, this RNG model generates more cash flow than CHP ($140-450K for low RIN and $1.2-1.9M for current RIN). Gas utilities, brokers, and CNG retailers are potential purchasers at this pricing if DeRuyter negotiates a split of the RIN value with the purchaser.
3. Retail CNG plus RIN: If producers take RNG to the retail CNG market, where CNG is now selling for $1.85 and up, it generates much more revenue than CHP, especially if credits are added ($1.2-2M for low RIN and $2.2-3.5M for current RIN). Even if credits are not added, this scenario still generates more cash flow than the current CHP model.

Nutrient Recovery Conclusions

Three nutrient recovery scenarios were evaluated during the study. These were: (1) the existing screening/settling system, which partitions and exports fiber and phosphorus-containing manure fines from the effluent in the form of high-value products within a CHP model; (2) incorporation of a struvite crystallization process within an RNG model for production and export of primarily phosphorus but some ammonia as value-added fertilizer; and (3) combined ammonia-stripping and phosphorous solids settling within an RNG model for production and export of two bio-fertilizers. Conclusions from these analyses are:

- The existing screening/settling operation is quite elegant in its ability to produce value-added products with limited capital and operating input while reducing phosphorus-loading to the farm by greater than 50%. Notably, little is done in alleviating nitrogen concerns.
- While struvite enjoys strong interest and potential application to numerous other wastewaters (i.e. municipal and swine), digested dairy manure has proven quite problematic (Zhang et al, 2008). To compensate for known concerns and chemistry, additional chemical dosing procedures are required, increasing operating costs extensively. As a primarily phosphorus removal technology, the additional expenditures and highly negative cost structure make the system non-viable, especially given the already quite impressive phosphorus removal capability of the existing system.
- The combined system developed by WSU is also costly from a capital and operating standpoint, producing improved Pro Forma over baseline RNG-only scenarios only when the highest possible revenue assumptions were utilized. Importantly, if emerging technologies and markets could improve upon their costs and revenue structures, inclusion of nutrient recovery alongside AD could be instrumental in alleviating important CAFO concerns related to nutrient overloads, particularly those practicing co-digestion.

Staged Approach and Scale Issues

Upon detailed analysis, it was realized that a staged approach of sequential/overlapping phases beyond the current CHP operation is most warranted from a project development standpoint. These stages include the following go/no-go phases, each one aimed towards securing higher business value as well as environmental management.

1. **Substrate & enhanced CHP:** Secure high-energy substrate to boost biogas production that does not adversely affect fiber product or nutrient recovery, and which, in combination with additional generator capacity, boosts electricity revenue.
2. **RNG business structure:** Secure a developer/partner, financing/grants and "hosts" for common off-farm RNG infrastructure (distribution, pipeline injection, fueling), and long-term off-take agreements.
3. **RNG conversion:** Based on stages 1 and 2, convert the DeRuyter CHP operation to RNG production through an AD system that maximizes revenue from organic wastes.
4. **Full nutrient recovery:** As dictated by farm and regional nutrient mass balance, regulatory requirements, commercially available technology, and nutrient markets, implement full nutrient recovery as part of AD-based waste-to-revenue systems.

Basin-wide Model

An important question raised by this feasibility study is the optimal (or viable) scale for the development of manure-based AD systems within the Basin. At the decentralized end of the continuum is the 'stand alone' operation, such as DeRuyter. The capital cost of off-farm RNG infrastructure creates challenges for the single dairy operator and effectively requires that the dairy have at least several thousand cows and/or high energy substrate, as well as high-value long-term off-take agreements, to make it viable. At the other end of the continuum is the centralized 'community digester' and gas cleaning operation concept, which requires piping and trucking manure and substrate from miles away and then hauling nutrients and waste products back out to regional farms and perhaps out of the Basin.

An option recommended by the study team for additional evaluation involves a semi-centralized approach, whereby dairies within 1 to 2 miles send their manure slurry by pipelines to a 'hub' digester and gas cleaning operation located as close as feasible to a natural gas transmission line, where the RNG would be injected into the gas grid at a meter station hosted by the gas or pipeline utility. An example of an attractive scenario would be based on manure from 10,000 cows within a mile radius, supplemented with substrate that would boost biogas production to 1000-1200 cfm without adversely affecting fiber products or nutrient management. Such a facility could produce more than 9,000 RNG GGEs/day, take advantage of economies of scale for gas cleaning and off-farm RNG infrastructure, and move manure to, and effluent from, the digester via efficient pipelines. Notably, development of such a 'hub' approach could be replicated to other 10,000 cow-scale hubs, producing multiple hubs that encompass the entire Basin. Such a decentralized approach involving 10,000 cow hubs could alleviate the key concerns present within the other business approaches at either end of the scale (low biogas production volume, hauling manure on roads, etc.) while also allowing for economies of scale (shared nutrient and co-product markets, RNG fueling stations/markets, etc.) and more effective funding/construction timelines.

CONCLUSION

The potential rewards and risks associated with the AD-based waste-to-revenue systems and scaling approach proposed within the study are great. The underlying drivers – promisingly profitable conversion of wastes and nutrients to revenue, regulatory assurances, a fuel that is half the cost of diesel, and sustainable marketing benefits – are strong. So are key uncertainties – RNG valuation and long-term off-take agreements, environmental credits, support for off-farm infrastructure – and the high capital cost of the model. The national shift to methane fuels will address some of the impediments (fueling, natural gas vehicle availability), as will the maturation of environmental credit markets (RECs, RINs, carbon credits). The logical next step would be for private and/or public entities to pull together the elements evaluated in this study into a business plan and financing package that will likely require the coordination of several partners.

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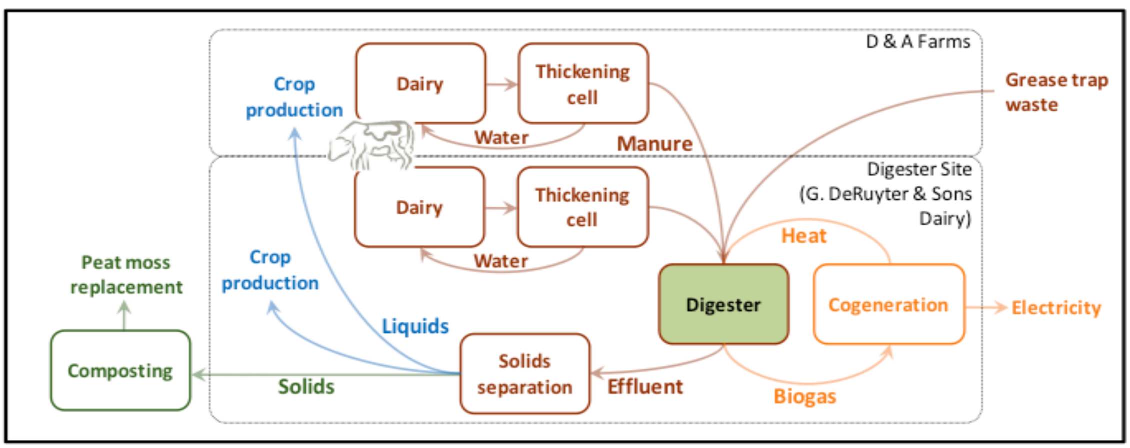
Chapter Two — Baseline DeRuyter CHP

Baseline DeRuyter Project

The Farm

With more than 5,000 dairy cows contributing manure, the DeRuyter digester is the largest digester currently operating in Washington, and the only one in eastern Washington. It is farm-owned and operated and was developed in 2006, receiving manure from two dairies: George DeRuyter & Sons Dairy and D & A Farms. Little to no off-farm substrates are entered into the digester, relying primarily on the concentrated flush manure feedstock to the digester (165,000 gallons of concentrated manure per day) (Figure 2.1). Separated fibrous solids are sold to Organix, a Walla Walla company, which uses them to produce a peat moss substitute called RePeet. Additionally, after separation of fibrous solids, manure fines -- containing organic material as well as a significant proportion of phosphorus -- are being separated and dewatered in settling weirs, allowing for sale of a second value-added product to a local fertilizer distributor. Biogas from the digester is sent to Guascor engine and generator sets for production of electricity and recovered heat. A portion of the recovered heat is used to maintain the temperature of the digester while the rest is released without value via a dump radiator. The electrical power is sold via Pacific Power to the grid.

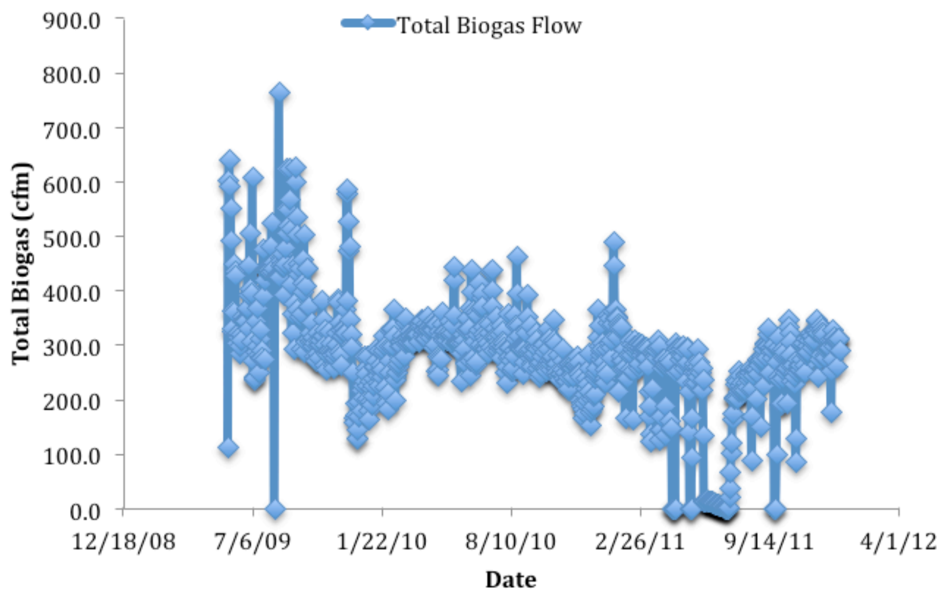
Figure 2.1: Schematic of DeRuyter digester project (WSDA, 2011)



The Anaerobic Digester

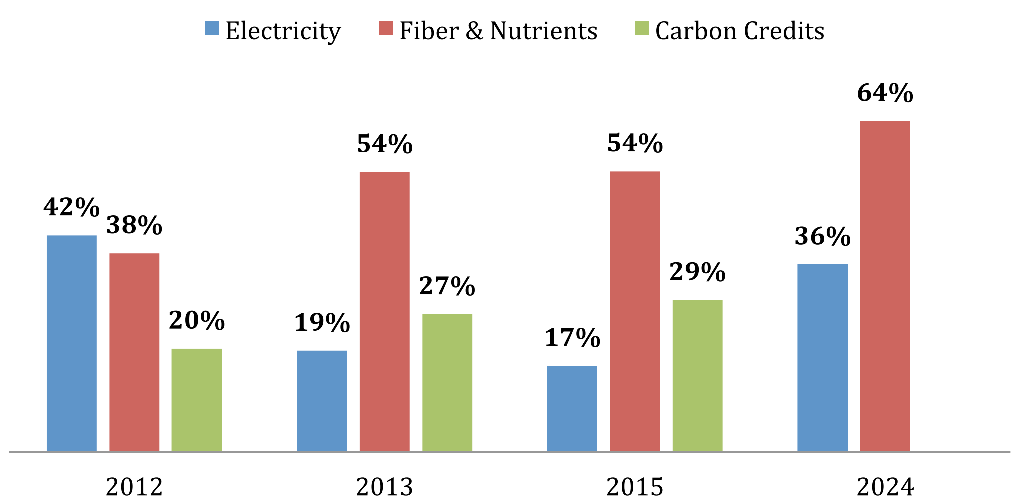
The DeRuyter project has little to no concerns with the actual construction and operation of the AD unit and its novel closed-loop concentrating basin/screen system. Quite stable operation and biogas production (Figure 2.2; 300 cubic feet biogas per minute at 60% methane content), with the exception of downtime for repairs, has been seen throughout the life of the project.

Figure 2.2: DeRuyter electrical production over time



This consistent gas production is emblematic of a stable digester with effective bacterial population and feed rates. The feed rates in themselves are a testimony of the concentrating basin/screen system to accumulate the majority of the organic fraction from a dilute 2% total solids (TS) wastewater to a 7-8% TS fraction more suitable for slurry-based digestion capable of positive heat balance. Gas productivity is calculated at ~90 ft^3 biogas/cow per day, which in comparison to a scrape digester using modified plug-flow technology that produces ~105 ft^3 biogas/cow per day, means that the flush concentrator is able to harness approximately 85% of the organic potential while exiting 15% in the overflow stream to the flush alleys.

Figure 2.3: Fraction of Net Revenue from Three Components



The DeRuyter project has three general sources of revenue: (1) electrical sales and associated credits/incentives; (2) fiber and nutrients; and (3) carbon credits resulting from the collection/utilization of methane which normally would be released to the atmosphere during non-digested storage in lagoons (Figure 2.3).

Electrical sales and associated credits/incentives

The DeRuyter project maintains two 600 kW engine/generators for a nameplate capability of 1.2 MW. The engines and generator sets have been operated at a 92 percent run time average at approximately 80 percent capacity, generating an average of 960 kW, or 8.4 million kWh per year. Of the 8.4 million kWh per year, 8 percent is used as parasitic load to operate the anaerobic digester, biogas, and fiber screening systems and 7.7 million kWh of ***electrical power are sold to Pacific Power***. The federal Public Utility Regulatory Policies Act (PURPA) adopted in 1978 requires electric utilities to purchase the output of qualifying small power production facilities that have a production capacity of no more than 80 MW. The DeRuyter project is in the last year of a three-year Power Purchase Agreement (PPA) with Pacific Power. PPA rates are subject to the review and approval of the Washington State Transportation and Utilities Commission (WTUC) which requires that utilities purchase power on "terms that do not exceed the utility's avoided costs for such electric energy" (WAC 480-107-095).

Under the existing agreement, the DeRuyter project is paid $0.0654 per kWh in 2012. Pacific Power and Light Schedule 37 Cogeneration and Small Power Production establishes the rates for the purchase of power from facilities that generate 2MW or less. On April 12, 2012 the WUTC approved a new tariff for Schedule 37, which is substantially less than the current price paid, reflecting reductions in Pacific Power's avoided costs. The approved tariff drops to $0.0350 per kWh in 2013, increasing to $0.0634 in 2021. These rates were used to project electricity sales revenues through 2021. To project Schedule 37 rates through 2032, the consultants assumed a 2.0 percent per year increase from 2022 to 2032. The maximum term for a Pacific Power PPA is five years. If the project enters into an agreement with Pacific Power in 2013, it would have a contract through no longer than 2018 with revised Schedule 37 rates going into effect in 2019.

The DeRuyter project, as currently designed, also has the opportunity to realize additional electricity revenue from the sale of ***Renewable Energy Certificates (RECs)***. Under the existing contract with the Bonneville Environmental Foundation, which expires in 2014, it is assumed that RECs are being sold at $.010 per kWh. A recently completed study for the State of Oregon reviewed the value of Oregon RECs generated by wastewater treatment plants (Oregon Department of Energy, 2012). The study, noting that REC pricing is not a consolidated market and significant pricing variation can be anticipated, identified three prices: a low price of $1.00/MWh based on the voluntary market; a medium price of $4.00/MWh based on current and near-future California REC prices; and a high price of $23.00/MWh based on the potential for higher California prices if Oregon RECs are treated the same as California-generated RECs. This financial analysis assumes that, in 2015, the price paid for DeRuyter RECs drops to the mid-point of the Oregon study, or $0.004 per kWh, with the rate increasing 10 percent every five years.

One Washington policy barrier, however, may prevent DeRuyter from realizing this REC revenue in the future. RECs, in most cases, are separate and distinct from the carbon credits from the avoided methane emissions, which are a significant source of additional revenue for the DeRuyter project. RECs capture the environmental benefits associated with the renewable electricity produced by the digester. These environmental benefits occur downstream from the digester, when additional electricity does not need to be produced from non-renewable sources. By most regulators this downstream renewable energy benefit is separate and distinct from the carbon credits that represent the avoided methane benefit at the project site.

That said, Washington's Renewable Portfolio Standard (created by voter-approved Initiative 937) uniquely does not allow a project to sell both RECs and carbon credits. The DeRuyter project currently avoids this problem by selling its RECs to the Bonneville Environmental Foundation, which uses the RECs on the voluntary market. The certification standard for the voluntary market, Green-E, allows projects to sell both RECs and carbon credits. The Climate Trust assumes, in the base case, that the DeRuyter project continues to sell RECs on the voluntary market and therefore continues to sell both RECs and carbon credits. The voluntary contract with Bonneville Environmental Foundation ends in 2014, however. There is therefore an additional risk in the base case scenario that the DeRuyter project will only be able to sell RECs to a buyer that will use them for compliance with the Washington law. In this scenario, the project would sell only carbon credits and forego REC revenue, because in 2015, carbon is worth $211,000 while RECs are worth $31,000. Proposals to change this provision of Washington's Renewable Portfolio Standard, which many consider to be a "technical fix" to the law, have been introduced in the legislature but have not yet passed.

RCW 82.16.120 authorizes "a ***customer investment cost recovery incentive payment*** to help offset the costs associated with the purchase and use of renewable energy systems located in Washington state that produce electricity" (WAC 4568-20-273). The incentive, which is paid by the participating utility, allows a maximum annual payment of $5,000 through 2020.

Figure 2.5 is a 20-year Pro Forma (2012-2032) showing the pre-tax cash flow for the DeRuyter project. Electricity sales and associated credits and incentive payments total $589,000 in 2012. These revenues are anticipated to drop substantially in 2013 with a decline in electricity sales prices and to decline further in 2015 with reduced revenue from RECs. Total revenue from electricity sales, credits, and incentives is reduced to $354,000 in 2013 and to $352,000 in 2015.

Operation and maintenance costs as well as labor estimates were identified through consultation with the DeRuyter Dairy. Repair and maintenance expenses are estimated at $0.027 per kWh, of which 90 percent is attributable to the generator; the project has 1.0 FTE employee. Total operating expense for the DeRuyter project in 2012 is $283,000, and anticipated to increase by 2 percent per year with inflation. Other expenses (i.e. property tax, truck expenses) are borne by the farm and not charged to the project.

The cost of maintaining the electrical generators, excluding labor, at $0.027 per kWh is $227,000 in 2012. Electricity revenue from sales and credits net of the cost of maintaining the generators drops from $361,000 in 2012, to $126,000 in 2013 and to $115,000 in 2015. The DeRuyter Project has ***debt service*** payments of between $226,000 and $264,000 per year through 2026. All debt has been issued with an interest rate of 1 percent.

Fiber and Nutrient Sales

The DeRuyter project sells fiber to Organix for production of a peat moss substitute. The farm produces between 3,000 and 4,000 cubic yards of fiber per month. Assuming the four fiber-pricing scenarios – $4.00, $5.50, $7.00 and $10.00/cubic yard -- evaluated by the project team and an average production of 3,500 cubic yards per month, the total revenue from fiber sales is anticipated to be between $168,000 and $420,000 in 2012.

Phosphorous solids from the digester effluent are screened, settled, harvested and sold to a fertilizer manufacturer, although it should be noted that DeRuyter has made only one sale of phosphorous solids so far, so it will take some time before the nature of this market is understood. This additional revenue stream started in 2012 with installation of a low-cost screening/separating process capable of recovering 50 percent of the phosphorus as solids settling from the digested flush manure. It is anticipated that 1,000 tons per year of phosphorous solids can be produced when the system is in full operation. This financial analysis assumes production grows to 1,000 tons per year by 2014, with 500 tons produced in 2012, and 750 in 2013. The price per ton has not yet been fully established. This financial analysis assesses four pricing options: $25.00, $50.00, $75.00, and $100.00 per ton. Similar to the fiber sales, there are no marginal costs to the production of phosphorous solids. The cost of delivering the phosphorous solids to the purchaser is not charged to the project by the farm. In contrast to electrical sales, fiber sales have effectively no marginal operating cost. The screens used to produce the fiber are part of the relatively low cost of operating the digester. Trucking of the fiber to the on-farm location where the fiber is converted to the peat moss substitute is a relatively low cost and is not charged by the farm to the digester. All costs of treating the fiber once it is at the on-farm processing site are borne by Organix. Phosphorous solid revenues under the above assumptions are $12,500 to $50,000 in 2012, growing to $25,000 to $100,000 in 2014.

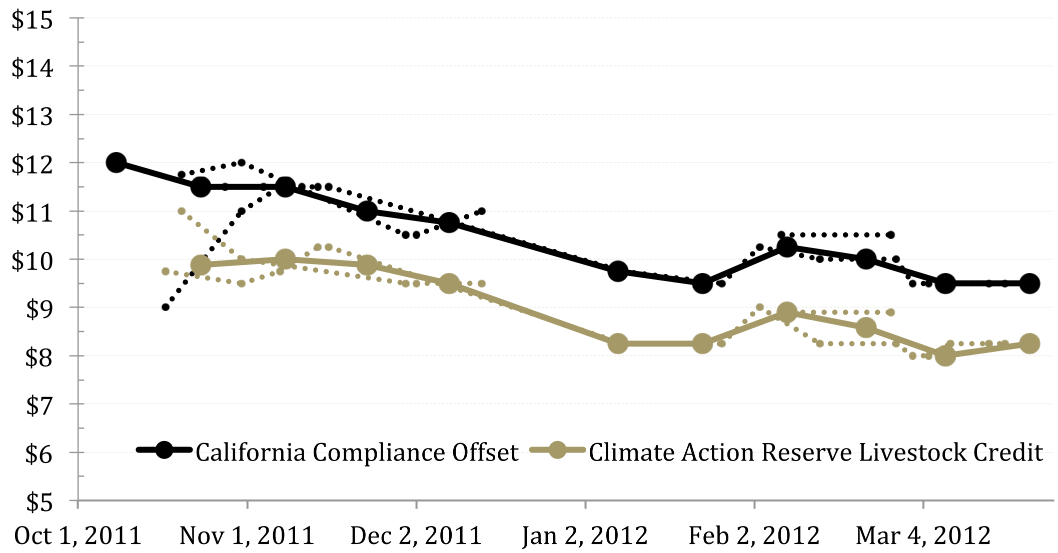
Carbon Credits

The DeRuyter project also has the opportunity to sell carbon credits for the digester's avoided methane emissions. Most projects are certifying their credits according to the Livestock Protocol from the Climate Action Reserve for use in the voluntary carbon market. The California Air Resource Board, the regulator overseeing the California carbon market that will begin in 2013, however, has recently approved a protocol for projects to count in California's market. Because this is a regulated market, prices are expected to be higher in California's market than what is currently available in the voluntary market. At the time of the publication of this report, however, the California market is not mature enough for projects to register carbon credits under the California protocol.

Recognizing the current voluntary market opportunity, and the possibility for credits to be sold in California's 2013 regulatory market, carbon credits from livestock digester projects are currently trading in the range of $7 to $9 per credit. As the California market moves forward and projects are able to register California offsets, these prices may increase further. Current prices are outlined in the graph below (Figure 2.4). Given this context, the project team assumed that the DeRuyter project continues to sell voluntary credits under the Climate Action Reserve Livestock Protocol in 2012 and 2013 at $8.50 per credit. Then in 2014, the project is assumed to transfer to the California program and sell its credits at $10.00 per credit. The anticipated revenue from carbon credits after transaction costs is $172,000 in 2012 and 2013, increasing to $199,000 in 2014.

Figure 2.4 California Carbon Credit Prices (Weisberg, 2012)

Thick lines represent the median bid carbon prices ($/credit) over the last six months. For a California Compliance Offset, the seller guarantees to provide an offset that complies with California regulations. A Climate Action Reserve Livestock Credit represents an existing credit that will need to be converted for California eligibility. Dotted lines represent specific prices, to give a sense of the variability of price data from different brokerage services.



The project team modeled the number of credits to be generated by the DeRuyter project using the Climate Action Reserve Livestock Calculation Tool Beta Version 3.0a. Given assumptions gathered from the site visit and discussions with Peter Freed at Terra Pass who is currently managing the carbon credits from the project, two scenarios were modeled: the current scenario in which the digester is fed manure of 5,000 cows and produces 283 cubic feet of biogas per minute which generates 21,063 carbon credits (or metric tons of carbon dioxide equivalent emission reductions) per year; and a second scenario in which additional substrates are taken to the digester increasing biogas production from 283 to 537 cubic feet of biogas per minute.

None of the added feedstocks are eligible to be credited for avoided methane emission under the Climate Action Reserve Organic Waste Digestion,[1] because additional methane leaks from the digester. These additional methane project emissions reduce the overall carbon credits generated by the project to 17,495 credits/year; this loss in carbon revenue is more than made up for by the additional energy produced by the substrates.

The project team assumes that, in both scenarios, carbon credits will be generated through 2023. Normally projects can only generate credits for 10 years (with the option of being renewed if the project continues to meet the eligibility criteria of the newest protocol that will be available at that time). The project team assumes, however, that after two additional years of generating credits under the Climate Action Reserve Livestock Protocol, the project will transfer to using the California Air Resources Board protocol. When this transfer occurs, the project is allowed to generate 10 additional years of credits under the new protocol. Because this transfer does not occur until 2014, the project remains eligible to generate credits through 2023. It is important to note that, as currently drafted, the California carbon market will end in 2020. The market for those credits generated after 2020 is not guaranteed; revenue from these post-2020 credits is still included, however, because it is anticipated that there will continue to be a state or federal carbon market.

In summation then,

- Under current scenario (5,000 cows feeding the digester, which generates 283 cubic feet of biogas per minute), the project will generate 21,063 carbon credits per year.
- Under a scenario in which the project takes on new substrates and generates 537 cubic feet of biogas per minute, the project will generate 17,495 carbon credits per year.
- The project will be eligible to generate carbon credits until 2023, generating voluntary credits in 2012 and 2013 and then transferring to the California market and generating ten additional years of credits.

[1] Under this protocol, only projects that digest postconsumer food waste or agro-industrial waste previously managed in an anaerobic lagoon qualify to generate carbon credits for the additional avoided methane emissions that result from digesting substrates other than livestock manure

Transaction costs, 50 percent of which are anticipated to be borne by the DeRuyter project, must be considered, as monitoring and verification of carbon credits can be quite time consuming and costly. Three separate transaction costs are accounted for. The Pro Forma assumes that these transaction costs are split between the DeRuyter project and the buyer of the credits.

1. Verification- The project is verified annually, even though the project could likely be verified every other year under the most recent version of both the Climate Action Reserve and California Air Resource Board Protocol. Verification is assumed to cost \$8,500 per year, with 2% inflation each year.
2. Registry fees- A cost of \$0.23 per credit registered with the Climate Action Reserve or other California approved registry. This is the cost of registering and then transferring a credit under the Climate Action Reserve's current fees, which are used to approximate California market fees that are still unknown.
3. Transfer to California Verification- A desk review is assumed to occur in 2014 to approve the previous credits generated by the project to be used in the California market. While still uncertain, this review is assumed to cost \$10,000.

Baseline Pro Forma Specifics

Figure 2.5 and Table 2.1 are graphical and tabular representations of the changing cash flow for the project based on the above discussion. In summary, the pre-tax cash flow for the DeRuyter Project is anticipated to be \$583,000 in 2012 with medium fiber and nutrient sales revenue. As shown in the chart, net cash flow drops substantially in 2013 to \$366,000, then stabilizes and drops again in 2024 to \$394,000, and then increases.

The changes in cash flow result from:

- **Revenues from electrical sales decreasing**. Electrical sales revenue is anticipated to drop by 46 percent from 2012 to 2013 and is anticipated to remain relatively low throughout the 20-year period. This reflects changes in the avoided cost calculation that underlies the regulated prices paid by Pacific Power.
- **Revenues from renewable energy credits decreasing**. Revenue from renewable energy credits is anticipated to drop by 60 percent with the expiration of the current contract in 2014, reflecting changed market conditions.
- **Revenues from fiber and nutrient sales increasing.** DeRuyter initiated fiber sales in 2011 and nutrient sales in 2012. These sales will account for an increasingly large percentage of revenue. It must be noted that these are new markets and revenues may fluctuate.
- **Carbon credit revenue increases.** Carbon credits are anticipated to generate additional revenue from higher prices starting in 2014 and remain relatively high until the end of carbon credit eligibility in 2023.

- **Debt service.** Debt service payments end in 2027. This Pro Forma does not include additional debt service that may be incurred to reinvest in the digester.

CONCLUSION

The DeRuyter project is located in eastern Washington, with different opportunities and challenges than those projects developed in northwest Washington under the auspices of Puget Sound Energy — especially projects reliant on better electricity sale prices and abundant in substrates that generate significant tipping fees. As a result, DeRuyter has been forced to more actively pursue other value-added off-take markets, namely fiber and nutrient sales. This has been a major accomplishment, and analysis of the Baseline Pro Forma clearly shows that, if not for the presence of these additional revenues, project cash flow would be problematic. Presently, and with upcoming negative changes to electrical sale prices and term-life of carbon credits, the Pro Forma does show positive pre-tax cash flow under several scenarios, rising as time goes by, particularly when debt service is paid off. Clearly, though, from personal communication, the project owners feel quite threatened by the impending changes and the overall success/viability of the project given potential other unidentified constraints and the present limited value of the cash flow. For the DeRuyter project and the Basin as a whole, further review and discussion on new models for business plans related to eastern Washington farm-based digester projects must be evaluated — ones that focus on continued reliance/improvement in nutrient and value-added product sales as well as new off-takes for biogas such as RNG.

Figure 2.5: Graphical representation of changing cash flow to DeRuyter Project

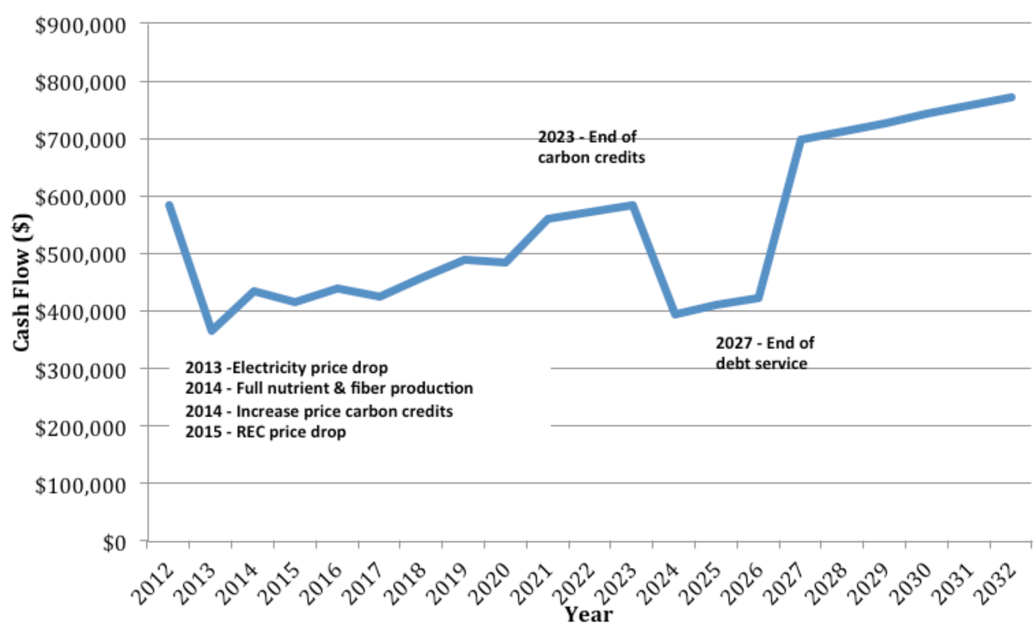


Table 2.1: Baseline DeRuyter Pro Forma

	2012	2013	2014	2015	2020	2025	2030
Revenue							
Electricity Produced/Rate							
Electricity Generation (kWh)	8,409,600	8,409,600	8,409,600	8,409,600	8,409,600	8,409,600	8,409,600
Electricity Used in Digester	672,768	672,768	672,768	672,768	672,768	672,768	672,768
Net Electricity Available for Sale	7,736,832	7,736,832	7,736,832	7,736,832	7,736,832	7,736,832	7,736,832
Electricity Purchase Price (per kWh)	$0.0654	$0.0350	$0.0382	$0.0408	$0.0530	$0.0686	$0.0757
Renewable Energy Certificate Price (per kWh)	$0.0100	$0.0100	$0.0100	$0.0040	$0.0044	$0.0048	$0.0053
Projected Revenue Electricity							
Electricity Sales	$506,144	$271,129	$295,233	$315,732	$410,069	$530,596	$585,821
Renewable Energy Certificates	$77,368	$77,368	$77,368	$30,947	$34,042	$37,446	$41,191
Washington State Renewable Energy Incentive	$5,000	$5,000	$5,000	$5,000	$5,000		
Sub-total Electricity Revenues	*$588,512*	*$353,497*	*$377,602*	*$351,679*	*$449,111*	*$568,042*	*$627,012*
Fiber Sales							
Cubic Yards Per Year	42,000	42,000	42,000	42,000	42,000	42,000	42,000
Price per cubic yard							
Sub-total Fiber Revenues Low	*$168,000*	*$168,000*	*$171,360*	*$174,787*	*$192,979*	*$213,065*	*$235,241*
Sub-total Fiber Revenues Medium Low	*$231,000*	*$231,000*	*$235,620*	*$240,332*	*$265,346*	*$292,964*	*$323,456*
Sub-total Fiber Revenues Medium	*$294,000*	*$294,000*	*$299,880*	*$305,878*	*$337,714*	*$372,863*	*$411,671*
Sub-total Fiber Revenues High	*$420,000*	*$420,000*	*$428,400*	*$436,968*	*$482,448*	*$532,662*	*$588,101*
Nutrient Sales							
Tons Per Year	500	750	1,000	1,000	1,000	1,000	1,000
Price/Ton							
Low	$25	$25	$25	$26	$28	$31	$34
Medium Low	$50	$50	$50	$51	$56	$62	$69
Medium	$75	$75	$75	$77	$84	$93	$103
High	$100	$100	$100	$102	$113	$124	$137
Sub-Total Nutrient Revenues Low	*$12,500*	*$18,750*	*$25,000*	*$25,500*	*$28,154*	*$31,084*	*$34,320*
Sub-Total Nutrient Revenues Medium Low	*$25,000*	*$37,500*	*$50,000*	*$51,000*	*$56,308*	*$62,169*	*$68,639*
Sub-Total Nutrient Revenues Medium	*$37,500*	*$56,250*	*$75,000*	*$76,500*	*$84,462*	*$93,253*	*$102,959*
Sub-Total Nutrient Revenues High	*$50,000*	*$75,000*	*$100,000*	*$102,000*	*$112,616*	*$124,337*	*$137,279*
Carbon Credits							
Credits per Year	21,063	21,063	21,063	21,063	21,063		
Price per Credit	$8.50	$8.50	$10.00	$10.00	$10.00		
Transaction Costs	-$6,672	-$6,806	-$11,942	-$7,081	-$7,818		
Sub-total Carbon Credits Revenue	*$172,363*	*$172,230*	*$198,688*	*$203,549*	*$202,812*		
Tipping Fees	$0	$0	$0	$0	$0	$0	$0
Total Revenue							
Fiber and Nutrient Revenue Low	**$941,375**	**$712,477**	**$772,650**	**$755,515**	**$873,057**	**$812,191**	**$896,572**
Fiber and Nutrient Revenue Medium Low	**$1,016,875**	**$794,227**	**$861,910**	**$846,561**	**$973,578**	**$923,175**	**$1,019,107**
Fiber and Nutrient Revenue Medium	**$1,092,375**	**$875,977**	**$951,170**	**$937,606**	**$1,074,100**	**$1,034,158**	**$1,141,641**
Fiber and Nutrient Revenue High	**$1,230,875**	**$1,020,727**	**$1,104,690**	**$1,094,196**	**$1,246,988**	**$1,225,041**	**$1,352,391**
Operations Cost							
Maintenance & Repair Generators							
Maintenance & repair - per kWh - for generators (90%)	$0.027	$0.027	$0.028	$0.028	$0.031	$0.034	$0.038
Sub-total Generator Maintenance & Repair Cost	*$227,059*	*$227,059*	*$231,600*	*$236,232*	*$260,820*	*$287,966*	*$317,938*
Maintenance & Repair Digester							
Maintenance & repair - per kWh - for digester (10%)	$0.003	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004
Sub-total Digester Maintenance & Repair Cost	*$23,210*	*$23,675*	*$24,148*	*$24,631*	*$27,195*	*$30,025*	*$33,150*
Labor	*$33,000*	*$33,660*	*$34,333*	*$35,020*	*$38,665*	*$42,689*	*$47,132*
Total Cost	**$283,270**	**$284,394**	**$290,082**	**$295,883**	**$326,679**	**$360,680**	**$398,220**
Net Income							
Fiber and Nutrient Revenue Low	**$658,105**	**$428,083**	**$482,568**	**$459,632**	**$546,378**	**$451,511**	**$498,352**
Fiber and Nutrient Revenue Medium Low	**$733,605**	**$509,833**	**$571,828**	**$550,677**	**$646,899**	**$562,494**	**$620,886**
Fiber and Nutrient Revenue Medium	**$809,105**	**$591,583**	**$661,088**	**$641,722**	**$747,420**	**$673,478**	**$743,421**
Fiber and Nutrient Revenue High	**$947,605**	**$736,333**	**$814,608**	**$798,313**	**$920,309**	**$864,361**	**$954,171**
Debt Service	-$226,000	-$226,000	-$226,000	-$226,000	-$264,000	-$264,000	$0
Net Cash Flow - Pretax							
Fiber and Nutrient Revenue Low	**$432,105**	**$202,083**	**$256,568**	**$233,632**	**$282,378**	**$187,511**	**$498,352**
Fiber and Nutrient Revenue Medium Low	**$507,605**	**$283,833**	**$345,828**	**$324,677**	**$382,899**	**$298,494**	**$620,886**
Fiber and Nutrient Revenue Medium	**$583,105**	**$365,583**	**$435,088**	**$415,722**	**$483,420**	**$409,478**	**$743,421**
Fiber and Nutrient Revenue High	**$721,605**	**$510,333**	**$588,608**	**$572,313**	**$656,309**	**$600,361**	**$954,171**

Notes: Pro Forma without replacement of digester or other equipment in 2026 (Year 20 of life)

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Weisberg, P. (2012) Aggregated data from personal communications with Karbone, BGC Environmental Brokerage Services, L.P., Amerex, ICE, Carbon Finance, Carbon Trading and Point Carbon.

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Chapter Three — Non-RNG Options From Baseline

INTRODUCTION

As can be seen from the baseline analysis of the DeRuyter CHP system, even at lowered electrical contract prices and assuming effective continuation and growth of value-added markets, the baseline operation can lead to a positive pre-tax cash flow. In order to alleviate some project risk and to potentially maintain a more positive cash balance, several non-RNG options were analyzed before the report delved deeply into the specifics of a new RNG market proposition. Two scenarios were considered.

The first envisions the project not being able to successfully acquire substrates to any appreciable extent, thereby precluding options for additional biogas production or even RNG as future chapters will detail. A course of action to be considered under such a scenario is cessation of CHP production and operation of the digester merely for boiler heat and treatment of saleable digester products. In essence this scenario considers the debate of whether or not limited electrical received prices offset the CHP operation and maintenance expenses, especially given that much of the project revenue resides not in electricity but downstream value-added products such as fiber and existing separated nutrients.

The second scenario does consider substrate collection to a desired 30 percent volumetric loading and doubling of biogas potential achievable, and as a result studies the impact the extra biogas and produced electricity can have on cash flow. Within this scenario are two sub-cases: one which assumes no additional engine set purchase and maintenance of the present 1.2 MW nameplate capacity and a second that includes purchase of a third engine set so as to allow for full use of the additional biogas and production of 2 MW. As with later RNG chapters, inclusion of substrates assumes no tipping fees, as unlike northwestern Washington projects, the eastern region, due to travel distances and multiple end-uses, is less likely to attain substrates, especially at any appreciable tipping fee arrangement.

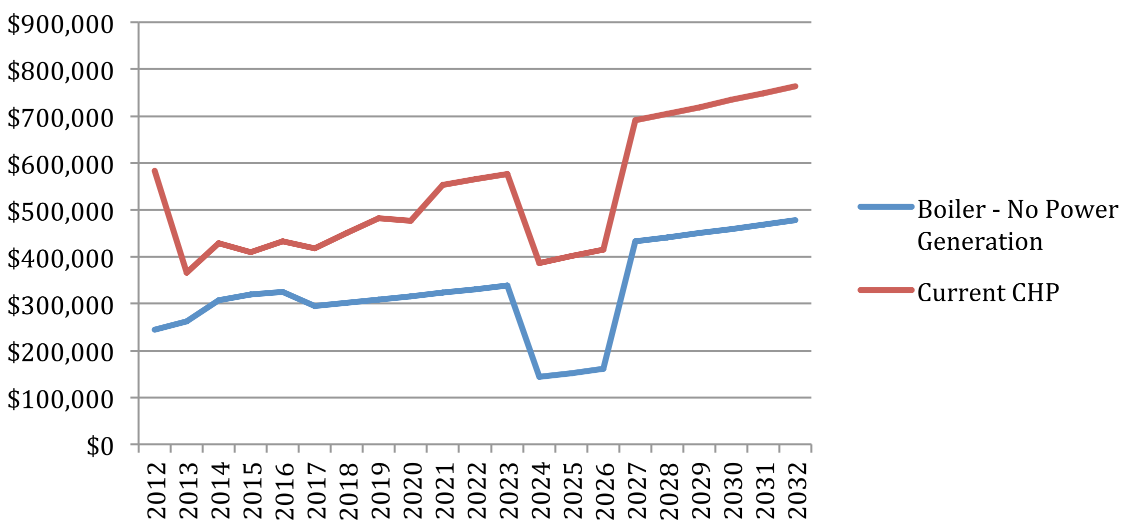
Scenario One—No Substrates, Boiler Substitution with CHP

Within this scenario all assumptions utilized in the Chapter 2 baseline CHP analysis were followed, except the following:

- All biogas produced is assumed to be utilized by a boiler as opposed to a CHP system. The boiler will supply thermal heat to the digester for its operation and excess heat at this time would be un-utilized through use of a dump radiator, although in the future (not considered in the Pro Forma) it would be hoped that value-added use could be attained for this thermal product.

- Existing engine sets would be sold at 10 to 20 percent of their initial cost, while all operating and maintenance costs associated with their use would be removed and replaced with limited operation and maintenance of the boiler assumed to be the same as the current cost of operating the digester.
- A boiler is estimated to cost $200,000. For the purposes of this analysis, it is assumed that the boiler can be acquired for the value of the generator sets resulting in no increase in debt service. Efficiency of the boiler system is assumed to be 80% and capable of providing more than enough thermal capacity to meet the digester needs.

Figure 3.1: Comparison of existing CHP and boiler replacement



As can be seen from Figure 3.1, the current CHP operation will produce more cash flow than a boiler only operation. This is because even with the drop in value of electricity prices and RECs, electricity generation with its relatively large share of system operation/maintenance costs continues to generate a small net income over its direct expenses.

Scenario Two—Substrates at 1.2 and 2.0 MW production

Within this scenario assessment, all previous assumptions developed for the baseline CHP Pro Forma, discussed in Chapter 2, are maintained with the following exceptions:

- Under the 1.2 MW sub-case it is assumed that the extra substrates will allow for more biogas production than is needed to consistently produce 1.2 MW, but that for considerations related to the engine set purchase, production would be maintained at the existing nameplate capacity, albeit higher than the present production below that nameplate capacity.

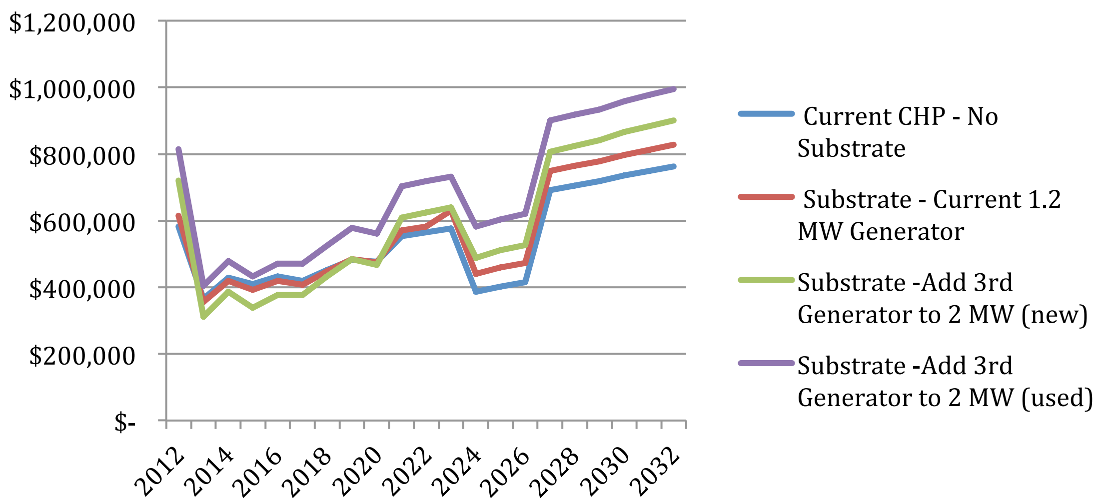
- Under the 2.0 MW sub-case it is assumed that a similar engine set would be purchased, providing generating capacity nearing 2.0 MW. Although the extra substrates might allow for even more biogas production, the existing Pacific Power tariff structure will cap power sales at 2.0 MW.
- In both sub-cases, it is assumed that engine set maintenance and repair costs rise according to the increased electrical production upon which service is based.
- In both sub-cases, addition of substrates requires an additional $15,000 in a one-time capital cost expenditure as well as an additional electrical draw from a 10 HP digester agitator.
- In both sub-cases, carbon credit revenue is reduced to reflect the addition of substrate as discussed in the last chapter.
- In the case of the 2.0 MW sub-case, an additional engine set is to be purchased and installed at an assumed cost of $1,100,000 using a 7 percent interest loan over 20 years. A scenario is also shown assuming the purchase of a used generator at 10 percent of the $1.1 million cost of a new generator.
- In all cases, the assumed production, quality of product, and sales from the effluent of the digester stay constant.

As can be seen from Figure 3.2, the 1.2 MW option produces cash flow that is similar to the existing revenue stream until the end of carbon credit eligibility when it produces more revenue. This is because the increase in electricity revenue is offset by the loss in credit carbon revenue as the electricity price drops and the value of carbon credits increases in 2015. In 2027, when credit carbon revenue is anticipated to end, the 1.2 MW option produces more cash flow than the current CHP model. The 2.0 MW option produces more cash flow than all other scenarios, particularly if a used generator set is acquired to produce the power.

CONCLUSION

Analysis of the two scenarios via Figures 3.1 and 3.2 clearly show that prior to any analysis of a future RNG enterprise, options related to CHP are most positive from a cash flow basis with respect to acceptance of substrates and generation of 2.0 MW of electrical power. The overriding assumption to this scenario though is an ability to acquire substrates in a reliable manner, which does not disrupt DeRuyter's emerging value-added post-AD product opportunities related to fiber and fertilizer. An additional concern is the farm's ability to handle and process potentially higher nutrient loads to the farm as a result of receiving the additional substrate. A detailed analysis of the impacts such an operation would have on existing nutrient management plans would be required and development of a new management plan would require projections in regard to needs for additional nutrient recovery technology, which could potentially impact any cash value gains highlighted in this analysis. Finally, it should be noted that DeRuyter is reluctant to saddle the farm with additional debt.

Figure 3.2: Pre-tax cash flow with four different scenarios



References

No references

Chapter Four — RNG Market Analysis

INTRODUCTION

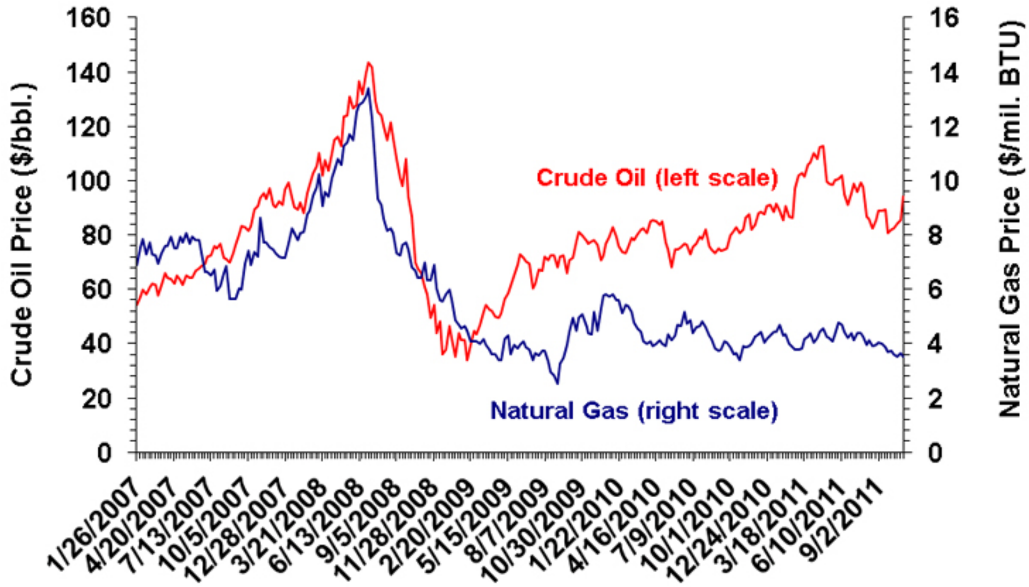
The purpose of this section is to evaluate the opportunity to sell RNG produced at the DeRuyter Dairy, describing the potential RNG market – RNG price and terms – and identifying potential purchasers. It includes an analysis of several RNG pricing scenarios: as commodity natural gas; commodity value plus a "green premium" (i.e., plus RIN value); and retail CNG plus "green premium." These RNG pricing scenarios are compared to the DeRuyter CHP baseline in chapter six of the report. Also described in this section are the logistics associated with several RNG delivery pathways, potential RNG purchasers in the central Washington area, and expansion of the RNG model to other dairies and RNG/CNG distribution partners.

NATURAL GAS MARKET REVIEW

The United States is beginning an "historic shift" to natural gas with recent production breakthroughs that, for the first time in history, have given the U.S. decades of low-priced natural gas (Novak 2012). Until recently, natural gas has been a relatively volatile commodity, fluctuating with supply and demand swings from less than $2/MMBTU to $15/MMBTU over the last two decades, closely aligned to petroleum price swings. In the last several years, natural gas exploration and production associated with mammoth shale gas plays provides unprecedented reserves and the promise of relatively low, stable prices for gas and a "decoupling" from increasingly costly petroleum products (Figure 4.1). This dynamic is driving shifts to natural gas for heating, manufacturing, and electricity production, and to methane fuels – CNG, LNG, and, perhaps, RNG – for transportation.

The absence of three factors has impeded a tip from petroleum to methane transportation fuels: 1) price and supply stability; 2) fueling infrastructure; and 3) availability of natural gas vehicles (NGVs) that can use CNG or LNG. With new assurance of vast domestic gas supplies and CNG retailing for about half the price of gasoline and diesel, price and long-term supply strongly favor methane fuels. The scarcity of CNG/LNG fueling infrastructure and NGVs, however, has presented a chicken and egg impediment that has only recently begun to yield to the economic, environmental, and energy security advantages of methane-based transportation fuels.

Figure 4.1: Decoupling of gas and petroleum pricing



Recent progress reducing these impediments is seen in the growing availability of new cars, trucks, and ship propulsion systems that can use methane fuels, combined with recent EPA certification of conversions for popular light-duty and heavy-duty truck engines. For example, the project team took note of the newly-approved EcoDual conversion for the Cummins ISX 15-liter engine that is widely used in the mountainous west; runs on either diesel or a mix of natural gas and diesel (displacing approximately 70% of the diesel); can be installed for $25-$35,000 by Seattle-based World CNG;, and is anticipated to have an ROI of less than 12-months for heavy fuel users at current CNG and diesel prices. In addition, several CNG retailers are building out fueling station networks on major truck routes and interstate highways, which will reduce this remaining impediment over the next several years. Although problems associated with hydraulic fracturing of gas-producing shale ("fracking") and fugitive methane emissions have generated environmental and other concerns, industry practices, regulation, and maturing technologies are focusing on these concerns, with a general expectation that broad-scale shale gas production will continue.

RNG, as a member of the methane fuels family, should benefit from the tip to methane fuels. The question is whether there is an economically viable place for RNG along with low-cost CNG and LNG from geologic sources. Can RNG compete with natural gas at the commodity or retail levels? After discussions with fleet operators and industry observers, the project team developed and evaluated the following three RNG pricing scenarios:

Scenario 1: Commodity Price. RNG is priced at the commodity value of natural gas with no "green premium" (e.g., REC or RIN value).

Scenario 2: Commodity plus "green premium" (RIN). RNG is sold as transportation fuel generating RIN values in addition to the commodity value. Two RIN values are analyzed:

current RIN ($0.74 per 77,000 BTUs or $1.10 GGE) and a lower RIN ($0.25 per 77,000 BTUs or $0.37/GGE).

Scenario 3: Retail CNG price plus RIN. The RNG is dispensed at a fast fuel station as transportation fuel at CNG prices, while also generating RIN values.

Scenario 1: Commodity Price

The base case (lowest value) scenario for the price of RNG is the commodity (pipeline wholesale) value of natural gas from geologic sources. National forecasts by the U.S. Energy Information Administration (EIA) project growing reserves of domestic natural gas supply at relatively low and stable prices. This is largely due to the discovery and production of new supplies of shale gas in the Mountain West of U.S. and Canada, the South, and throughout the Northeast's Appalachian Basin. This unprecedented development opens the door for greater use of methane fuels, including RNG, in the high-value transportation fuels market, but it also makes it difficult for RNG to compete with low-cost natural gas as a commodity product.

This analysis assumes that DeRuyter receives the Sumas Cascade commodity price (i.e. the wholesale price for gas at the Washington/Canada border) for its gas. The Sumas Cascade price was estimated based on the March 2012 EIA forecast for prices at the Henry Hub reduced by the projected difference between the Henry Hub price and the Sumas Cascade Price in the Cascade Natural Gas 2011 Integrated Resource Plan. Under this analysis, the Sumas Cascade price forecast is $3.87 per MMBTU ($0.44/GGE) in 2014 increasing to $6.07 per MMBTU ($0.69/GGE) in 2032. It assumes RNG is injected into the pipeline grid and is purchased at that point (Table 4.1).

Table 4.1: Projected price of commodity natural gas and retail CNG, 2014 - 2032

$/MMBTU	2014	2016	2018	2020	2022	2024	2026	2028	2030	2032
Henry Hub	$4.16	$4.30	$4.59	$4.80	$5.29	$5.64	$5.98	$6.18	$6.19	$6.67
Sumas Discount	7%	9%	12%	10%	13%	11%	11%	10%	10%	9%
Total	$3.87	$3.91	$4.04	$4.32	$4.61	$5.02	$5.33	$5.58	$5.57	$6.07
% Change		0.43%	2.51%	0.97%	4.93%	4.80%	5.54%	0.27%	-0.03%	3.61%
CNG Retail Price	$1.85	$1.87	$1.93	$2.06	$2.21	$2.40	$2.55	$2.67	$2.66	$2.90

Source: U.S. EIA Early Outlook 2012 and Cascade 2011 Integrated Resource Plan Projections

Scenario 2: Commodity plus "green premium" (RIN)

If RNG can be injected into the pipeline grid, it can be distributed locally or "wheeled" to distant purchasers, offering a vast potential market for RNG. As a renewable fuel, RNG can in some cases qualify for Renewable Energy Credits if the RNG is used to produce electricity[2], or for

[2] Different state Renewable Portfolio Standards have different rules around if and how RNG put into a pipeline to be used at a power plant can generate RECs. The California Energy Commission, for example, recently decided that projects whose gas is not injected into a dedicated pipeline that serves California power plants cannot for now generate RECs in California.

Renewable Identification Numbers (RINs, under the Renewable Fuel Standards (RFS) program) if the RNG is used as transportation fuel.[3] This analysis focuses on the RIN as the green premium, noting regional utilities have an oversupply of renewable power, primarily from wind farms, and RECs are considerably lower in value than RINs, at least for the time being.

The RIN value is realized at the point the compressed RNG is put into motor vehicles. If RNG is put into the pipeline at the DeRuyter project, and then compressed and used for fuel off-site, the RIN is generated off-site. A portion of the value of this RIN, however, should be reflected in the price the DeRuyter project is paid for the gas it injects. The ability for RIN revenue to be realized downstream should effectively increase the value of the RNG at pre-delivery stages as well. Two RIN values were evaluated: the current value of $0.74 per 77,000 BTUs (which equates to $1.10/GGE) and a projected lower RIN value of $0.25 ($0.37/GGE). Commodity plus green premium pricing appears to be a viable approach in selling RNG to gas utilities, gas brokers, and CNG/LNG retailers, noting they will likely require some sharing of the RIN or REC value. Under this scenario, the sale of RNG from DeRuyter to a gas utility in 2014 would include the Sumas Index price of natural gas ($3.87/MMBTU or $0.44/GGE) plus an agreed percentage of the RINs. If the producer of the fuel were to split 50% of the RIN revenue with DeRuyter, this green premium would add $0.55/GGE at the current RIN rate or $0.19/GGE at the lower RIN rate, providing DeRuyter with a total of $0.99/GGE at the current RIN value or $0.64/GGE at the lower RIN rate.

Scenario 3: Retail CNG price plus RIN

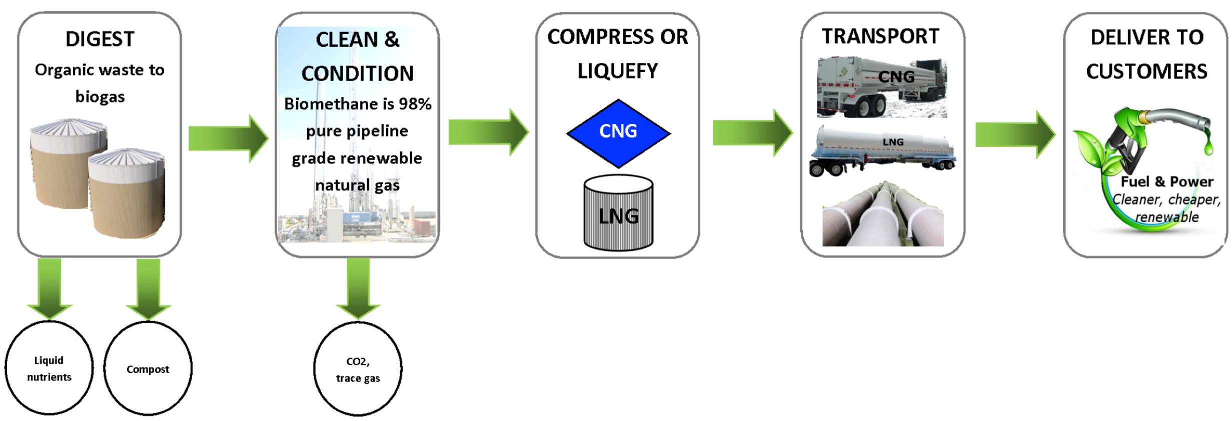
The current retail price of CNG in the Seattle area is between $1.85 and $2.14/GGE. This analysis assumes that the price is $1.85/GGE in 2014 and changes at the same rate as changes in the Sumas Cascade commodity prices. Actual retail prices will be affected by the rate of introduction of CNG vehicles into the U.S. fleet, which may have a substantial affect on CNG prices. The potential of a "concerted U.S. policy effort to shift the transportation sector away from oil toward natural gas would significantly increase demand, and thus natural gas prices" (PacifiCorp IRP 2011, pg. 29). Based on the combination of the retail price of CNG ($1.85/GGE – paid by the RNG customer) plus the applicable RIN rate (paid through the RFS program), the sale of RNG as a retail product with RINs would garner an estimated $2.94/GGE at the current RIN rate or $2.22/GGE at the lower RIN value in 2014. In this scenario, because the project itself cleans, compresses gas, and fuels trucks, it realizes 100% of the RIN revenue. As noted in the Economic Analysis and Environmental Credit sections below, the RINs and other "green premiums" are young markets, based largely on government policies, subject to fluctuations and uncertainties.

[3] The RIN market is described in detail in the Environmental Credit section of the report.

Potential RNG Purchasers and Delivery Logistics
Under the three RNG pricing scenarios, potential RNG purchasers fall into two categories: wholesale RNG buyers who resell the gas, and retail customers who are the end user of the RNG. Each category has associated delivery logistics that are described briefly in this section and factored into the RNG conversion design section and the *Pro Forma* in the Economic section.

Potential Wholesale RNG Buyers
Wholesale purchasers of RNG will usually require pipeline delivery of the gas so it can be delivered to customers in various locations on the natural gas pipeline grid. As noted above, values for wholesale RNG are set by the applicable index price for natural gas (e.g., Sumas or Henry Hub) plus the green premium (RIN or REC) minus a negotiated share of the total for the reseller (Scenario 2 above). A possible exception to the pipeline requirement would be direct delivery of RNG in tube trailers to gas/electric utility combustion turbines and supply-constrained industries and residential or commercial service areas (which would still require injection into that part of the grid using a utility-supplied injection point) (Figure 4.2).

Figure 4.2: RNG Production and Delivery



For pipeline delivery of RNG to wholesale customers, the **logistical requirements** include:

- **Gas cleaning equipment that meets applicable pipeline specifications:** RNG must meet rigorous gas quality standards ("tariff"), and real-time monitoring, to be injected into the pipeline system. Sensitivity to gas quality increases with distance, and reduction in gas volume, from the main transmission pipeline. At the end of a gas distribution system where volumes are low, the injected gas must closely match the ambient gas. The gas-cleaning unit evaluated in this feasibility study (Flotech's Rimu model) is capable of producing 98% pure methane and removing potentially problematic contaminants from biogas. However, pure methane has a heating value of 1000 BTUs/cubic foot, while the typical gas in central and western Washington has a heating value of approximately 1030 BTUs/cubic foot due to the presence of high-BTU constituents, such as propane, ethane, and butane. This does not present a problem if the gas is injected into the Williams NW pipeline or its Wenatchee Lateral that runs through the Yakima Valley (including Sunnyside), which requires gas entering the pipeline to have a heating value of at least 985 BTUs/cubic foot. It could present an issue if the RNG is injected into low flow areas, potentially requiring supplementation with propane to boost the BTU value of the RNG to closely match the gas in the pipeline.

- **Compression of the RNG for pipeline or tube trailer delivery:** A compressor at the back end of the gas cleaning unit is required to transport RNG through a pipe to the pipeline injection point (3.8 miles from the DeRuyter digester) and to pressurize the RNG for injection into the Williams pipeline (to approximately 700 psi). Alternatively, a larger compressor system would pump the RNG into tube trailers to pressures of up to 3600 psi.
    - **Transportation Option 1. Pipe to the Williams Pipeline:** Delivery to the gas grid can be made through the installation of a 3-inch gas pipeline along the existing Dekker Road right-of-way to its intersection with the Williams main pipeline (Wenatchee Lateral), where it would be injected through a meter station that would be built for this purpose. The cost of the pipeline is approximately $1.8 million. It would have sufficient surplus capacity to serve a number of other RNG producers or gas users in the area.
    - **Transportation Option 2. Tube trailer delivery to the pipeline or fueling station:** The alternative to a 3.8-mile pipe to the pipeline injection point is to shuttle the RNG in tube trailers. A state-of-the-art jumbo tube trailer can hold approximately 280,000 cubic feet of gas at 3600 psi, requiring two trips a day at the expected RNG production rate of more than 3500 GGEs/day, based on 500 cubic feet per minute biogas production. Tube trailer delivery also provides the option to deliver RNG directly to a fueling station (e.g., in Sunnyside or Ellensburg) or to other customers. This would have the advantage of avoiding the cost of an injection point and meter station, as well as taking advantage of the gas pressure in the tube trailer to reduce the cost of compressing gas from the pipeline (at 600-700 psi) to high pressure holding tanks (4700 psi) for fast fill dispensing at the fueling station. If there is not an injection point at the fueling station, however, additional storage at the fueling station and DeRuyter would be necessary and there would not be the option to serve other customers via the natural gas grid.
- **Injection point/meter station:** Getting RNG into the pipeline requires both a tap (injection point) into the pipeline and metering and monitoring equipment to assure the RNG meets pipeline specifications. This package of equipment typically includes a gas chromatograph, flow meter, filter, valves, telemetry for real-time reporting, and other features. The injection point/meter station is an expensive piece of infrastructure – approximately $1.3 million depending largely on land acquisition costs. A meter station typically has a 100' x 100' footprint and a small metal shed to house components. The cost of a meter station is not greatly influenced by size -- a meter station for a single small user, such as DeRuyter, would not cost much less than a meter station for five times that amount of gas. The high capital

cost and ability of others to use it at little additional cost make it a candidate for a public, co-op, or third-party hosted model.

- **Fueling Station:** Ideally, a CNG/RNG fueling station is in a location that can serve a number of fleets that consume hundreds or even thousands of gallons a day. The ideal facility would be on or near a high-flow gas transmission pipeline — with both a meter station for injection of RNG and the ability to withdraw natural gas — as well as high pressure storage tanks (4700 psi), booster compressor, and dispensers for fast fueling of CNG vehicles. Such a station reduces the need for expensive storage systems, is able to blend RNG and CNG, and provides certainty of supply. It would also likely cost $1.5 to $2 million. A more modest fueling station (used in this analysis), with pipeline access but without injection capability, is estimated to cost less than $300,000. Down the road, as LNG becomes the preferred fuel for long-haul trucking, it would include cryogenic tanks and dispensers for LNG fueling.

Potential **wholesale purchasers and terms** include:

- **Gas utilities:** Puget Sound Energy has expressed interest in purchasing RNG from these types of projects. It would sell the renewable gas with the potential to produce RECs or RINs to renewable energy brokers, retailers, or large end-use customers. It already participates in the RNG market through its involvement with the Cedar Hills landfill gas project. Puget Sound Energy has expressed interest in purchasing RNG from these types of projects. It would sell the renewable gas with the potential to produce RECs or RINs to end use customers utilizing the gas as a transportation fuel or for power generation in its own high efficiency generating plants to brokers serving similar markets. They already participate in the RNG market through their involvement with the Cedar Hills landfill gas project. Another Pacific Northwest utility, FortisBC, recently launched programs to market RNG to residential and commercial gas customers at a premium price which, combined with Canadian carbon pricing, enables it to purchase RNG from dairy farmers for $15.25 a gigajoule (approximately 1MMBTU, or more than $1.70/GGE). Fortis will purchase either pipeline-quality RNG or raw biogas, which Fortis will purchase at a lower rate and upgrade on-site for pipeline injection. Fortis indicated the purchase of Washington State RNG could be a possibility in cases of local supply shortage. Northwest utilities are considering similar RNG marketing programs.
- **Gas Brokers:** Project team members have been in contact with several national gas brokers who would be interested in discussing RNG purchase agreements on terms similar to those outlined for the gas utilities above.
- **Commercial CNG Retailers:** As Clean Energy, Pilot-Flying J truck stops, Marathon, and other CNG/LNG retailers build new natural gas fueling stations along major trucking routes, the demand for RNG is expected to increase. Transportation of food products for retailers such as Safeway, Wal-Mart, and Costco is a sector increasingly sensitive to its carbon

footprint. RNG from dairy manure can significantly reduce agricultural and transportation-related greenhouse gas (GHG) emissions. These purchasers may be willing to pay a few Cents more for CNG or LNG blended with RNG. Clean Energy is already marketing blended CNG/RNG as RNG10 and RNG20. Terms for the sale of RNG to these retailers are expected to be similar to the terms for sale of RNG to utilities (Scenario 2).

- **Military and other Government Purchasers:** To meet the military's "net zero" requirement by 2020, the Defense Logistics Agency (DLA) and the General Services Administration (GSA) are potentially major wholesale purchasers of RNG for vehicles as well as for other natural gas and propane applications. The same is true for other government agencies that have carbon emission reduction or renewable energy goals, such as the Department of Energy at Hanford, Washington. Terms for sales to the DLA, GSA, and other federal, state, and local agencies would be similar to gas utilities (Scenario 2) unless they contracted for fueling services, in which case the retail CNG plus RIN model (Scenario 3) would likely apply.

Potential Retail Purchasers of RNG

The project team employed several approaches to identify potential retail purchasers of RNG, the necessary logistics associated with their purchase needs, and possible purchase prices. In the Yakima-Sunnyside area, the project team conducted a series of personal interviews with fleet managers and representatives of organizations targeted as potential end users. Topic areas for discussion included their familiarity with the use of natural gas for transportation (CNG and LNG), awareness of biogas produced by local dairies, how their organization might value renewable energy benefits, what types of vehicles they have that could use RNG, logistical issues, and other possible concerns. Gathering information from available fleet lists identified more than two-dozen prospects to be interviewed. The interviews identified almost a dozen top prospects from among all the fleets in the area (Table 4.2).

The project team identified five stages of adopting new technologies: awareness, interest, evaluation, trial, and adoption. The following organizations were identified as initial participants of the RNG project. The selection criteria combined the stage of the adoption process they are in, the size and range of the fleet (technical applicability), and fleet visibility within the region. The majority of the groups in this top prospect list are in the "trial" stage. Within this context, it means that if a convenient source of compressed natural gas (CNG) and natural gas engines were to become more available to them, they would implement them. The companies chosen for this phase of the study are in a position to leverage resources to their aid. They have fleets large enough to amortize the investment while working with state and local agencies to bring other resources to the table to lower the overall cost of conversion. Costs of fuel and convenience were the top concerns while the green factor was the lowest concern with one exception. Haulers that cross into areas of stricter emissions regulation are aware of the needs for cleaner running engines, and that compressed natural gas offers them a solution for this issue.

Washington State Department of Transportation – South Central Region

The Washington State Department of Transportation (WSDOT) already has prior experience with CNG vehicles on the west side of the state. As a state agency, it is on the forefront of air quality compliance issues and is mandated by state law to use more alternative fuels. WSDOT must also work within constrained budgets for fuel costs. Given the size and areas covered, WSDOT is an excellent choice for RNG adoption on the east side as it could technically fuel anywhere in its service area. It also hub fuels its vehicles onsite. This activity could warrant a dedicated CNG fueling station at its Union Gap location. Vehicle types cover the range of WSDOT highway support vehicles, including snow removal as well as pickup trucks. New replacement pickup trucks, incorporating dual gas/CNG options, could be a best fit. The willingness of the local director plays an important part in implementing a project of this nature. WSDOT is considered an excellent candidate for early adoption.

City of Yakima

The City of Yakima transportation system consists of a wide variety of 550 city vehicles, including transit vehicles and waste haulers. Transit buses and waste haulers are good vehicle types for CNG conversion or replacement given their diesel engine fuel economy and high annual mileage and pollution contribution while idling. The city has its own refueling location, so providing CNG to that location would make a transition more easily attainable. Rising fuel cost is a vital concern to the city, and it is aware of the benefits of biogas both at the Yakima Regional Wastewater Treatment Facility and for the dairies throughout the area. City officials report that they can see the potential economic development benefits for their region.

LTI/Milky Way

Lynden Trucking, Inc. operates a high-mileage, long haul freight fleet across the country and regionally throughout the Northwest and Alaska. It is the current Washington state hauler for Darigold milk. For over the past year, LTI has been modeling cost-benefit data for a potential CNG fleet conversion and recently completed an internal study. This fleet represents a model for regional transportation that could be supported by CNG, and the viability of milk hauling operations being supported by RNG has already been demonstrated at the Fair Oaks Dairy Farm in Indiana. Fuel costs factor very strongly for this group, as do emissions, given the areas of travel and restriction on emissions in areas such as California. This group understands the importance of adapting to the change and is willing to look at newer technology to stay ahead.

Yakima Educational Service District (ESD) 105

Yakima ESD assists over 25 school districts and 23 tribal schools in its area, and is already aware of the positive potential for CNG use in vehicles. It could possibly leverage that volume for a regional CNG station, buses, engines, etc. A potential business model for the ESD members would be to buy new buses as needed and gradually convert the entire fleet to CNG over approximately 13 years. Their preference would be to establish a fuel site (from the pipeline or from tube trailers) at the location where buses are currently refueled. This could be a time-fill type station. As these are educational organizations, with tight budgets, it would likely take highly leveraged resources to bring a new station and the new vehicles online.

Sunnyside School District
The Sunnyside School District has a fleet of more than 45 buses. It is the district closest to the DeRuyter & Sons Dairy, which could make it a good potential fit for using the RNG the dairy could produce. It would be best served by on-site fueling at its bus location. The proximity of its location could make delivery by tube trailer very convenient also. The fleet manager is aware of the low mileage of the district's diesel school buses, and the cost of fuel is hurting them greatly. She is open minded and one of the key decision makers. Safety is the biggest concern as the buses transport children. The district currently has its own fuel station and could use it as a central hub.

City of Sunnyside
The Sunnyside fleet manager has suggested its small fleet of pickup trucks could be candidates for CNG conversion or replacement. The trucks have a small round-trip circuit that would enable them to refuel at a local CNG fueling station. The rising cost of fuel is a primary concern, as well as convenience of fueling. Paired with the Sunnyside School District, these two organizations could be a solid end-use market for the dairy's RNG.

Prosser School District 116
The Prosser School District has a modest fleet of 35 school buses, with several special needs buses all within an optimal route range for CNG refueling. The district is open to adapting new technology to lower operating costs as long as it is available and convenient.

Ray Poland and Sons
Ray Poland and Sons is very well informed about the latest technology, including truck engines and station equipment, and have been looking into CNG for the past several years. The company operates a small regional fleet of 15 vehicles and is looking for cost reductions in its operations, seeing CNG as a strong potential to reduce costs of operation.

Adams County Public Works
Adams County has a large fleet of haulers and light-duty trucks. It is familiar with CNG and is looking to reduce costs across the board, particularly fuel costs. The route distances and location make this a good potential for the county. The fleet manager expressed a willingness to consider and adopt new technology.

Franklin County PUD 1

Franklin County has a fleet of more than 100 vehicles, including 20 Class 7 trucks and lots of small pickups that would be ideal for conversion or replacement with CNG options. Vehicle routes and use patterns are considered to be within the optimum CNG range. The PUD currently fuels through commercial fueling sites, such a PetroCard, which it felt should have a CNG option. If fueling infrastructure for CNG comes in place, the PUD is very willing to move in that direction with its vehicle choices.

Kittitas County

Kittitas County operates a fleet of more than 70 vehicles with an ideal operating range for CNG. In its fleet, pickups and tractor-trailers would likely be the best candidates for using CNG. Staffs are familiar with CNG vehicles and are looking for lower priced fuel. The county has a local fuel contract. If a station could co-locate or provide CNG, that would be optimal.

Table 4.2 provides details about the top candidates identified by our survey of fleets in the area around the DeRuyter digester. The information includes the types of vehicles identified by each organization as the most likely to convert or replace for CNG. The awareness of CNG and "green" factor data is a subjective assessment based on our interviews. These are based on a 1 to 5 scale, where 1 is the highest awareness or the highest value given to green quality of the RNG fuel. The final column for "convenient location" identifies the organization's preference for logistics.

Application of the RNG model to other dairies

Yakima County has more than 93,000 milking cows, making it the leading dairy county in the state, surpassing Whatcom County, which has more than 60,000 dairy cows. Dan DeRuyter estimates there are 50,000 head within a seven-mile radius of his dairy. While there is no shortage of concentrated manure in the area for AD/RNG production, there are both opportunities and challenges in applying the RNG model to other dairies in the Sunnyside/Yakima area and statewide.

Challenges to broad adoption of the RNG model include:

- Competition for high-energy substrates that greatly improve (double in many cases even under a 30% limitation on non-dairy substrate) biogas production and generate tipping fees. On the east side of the Cascades, there are fewer sources of these substrate organic wastes and greater opportunities to use or recycle the wastes in various agricultural processes.
- Most of the dairies in the area do not have "free stall" barns and flush/scrape manure handling systems that facilitate AD/RNG production. Conversion of open corrals to free stall and flush/scrape operations is capital intensive and requires considerable water inputs.

- The high capital cost of RNG infrastructure, including gas cleaning units, RNG distribution (pipelines and/or tube trailers), pipeline injection point/meter stations, and RNG/CNG fueling stations.
- Unreliable incentives for RNG production (e.g., RECs, RINs, carbon credits, etc.) which can add significant but uncertain upside opportunities.
- Site-specific factors, such as proximity to other dairies for economies of scale, distance from major pipelines and fueling infrastructure, cropland nearby for application of excess nutrients.
- Spotty record of digester success, and the fact that digesting manure and substrates requires farmers or digester operators with the right skill sets to understand and master the science and art of anaerobic digestion.
- Immature or unproven technologies, especially in the nutrient recovery area, that may be a prerequisite for public support for AD.

Opportunities and factors supporting adoption of the RNG model include:

- Successful demonstration of the RNG model -- especially within the context of a digester-based "integrated systems approach" to the production of revenue-generating renewable fuel, nutrients, fiber products (compost and peat moss substitute), CO_2, and other "by-products" – will pave the way for other dairies to follow.
- Public, co-op, or third-party support or "hosts" for expensive RNG infrastructure, especially off-farm infrastructure such as pipeline injection/metering and RNG transportation systems including pipelines, tube trailers, and fueling stations that can be used in common by other RNG producers, which can reduce debt, risk, and generally make participation in the RNG model easier and more financially attractive.
- The rise in the cost of petroleum, the growing availability of CNG and natural gas vehicles and conversions for popular heavy-duty truck engines, and the resulting national shift to methane fuels in the high-value transportation fuels market, are compelling factors favoring adoption of the RNG model.
- Farmer efficiency and vertical integration – from manure management to AD to RNG production and transportation, and perhaps even to fueling and use (per the Fair Oaks Dairy RNG model in Indiana) – can greatly improve the economic viability and profitability of the RNG model.
- Governmental policies that support emerging RNG markets (RINs, RECs, carbon credits), which now can add large but unreliable revenues, to provide the greater certainty needed to make RNG investments bankable. In the meantime, entrepreneurs with deep pockets and a tolerance for risk can also help bridge the risk and uncertainty for a share of the potential RNG profits.

- Municipalities and other governments can help set the market for RNG by acting as early adopters of RNG and establishing procurement policies that provide bid preference for waste haulers and others who use RNG in recognition of the environmental, local economic, and community benefits of RNG.
- Regulatory requirements – to protect water and air quality, and public health -- are also driving dairies toward an AD systems approach that can turn polluting wastes into revenue-generating products.

References

Novak, A. (2012). The tectonic shift of new oil and gas technologies has only just begun, in Forbes Magazine, electronic version, February 16, 2012.

Table 4.2: Summary of potential end users of RNG

Organization	Candidate Vehicle Type	CNG Awareness Scale: 1 (High) to 5	"Green" Factor Scale: 1 (High) to 5	Annual Fuel Use (Mostly diesel)	Location
WSDOT: South Central Region	Large Utility Trucks, Pickup Trucks	3	2	120,000 gal (gas)	Local fueling station
City of Yakima	Transit	3	4	183,000 gal	On-site fueling location
LTI/Milky Way	Haulers	1	1	550,000 gal Seattle/Moses Lake 100,000 gal Sunnyside Area	Multiple fueling points
Yakima ESD	School Buses, Pickup Trucks	1	4	Not available	On-site fueling location
Sunnyside School District	School Buses	3	4	82,382 gal	On-site fueling location
City of Sunnyside	Pickup Trucks	4	4	*~ 50,000 gal*	On-site fueling location
Prosser School District 116	School Buses	4	4	100,000 gal	On-site fueling location
Ray Poland and Sons	Haulers	4	4	50,000 gal	Local fueling station
Adams County Public Works	Pickup Trucks	4	4	*~20,000 gal*	Local fueling station
Franklin County PUD 1	Class 7 Trucks, Pickup Trucks	4	4	19,000 gal	Local fueling station
Kittitas County	Class A Trucks	4	4	38,000 gal	Local fueling station

Chapter Five — RNG Design

While Chapter 4 was a summary of the RNG markets, opportunities/hurdles, and potential downstream infrastructure required for sales of produced RNG under various scenarios, this chapter focuses on on-site infrastructure and operation necessary to produce a relatively pure methane gas product at flow rates appropriate for effective scaling of identified technologies.

Biogas Flow

Presently, the DeRuyter project produces, on average, 269 cubic feet of biogas per minute (cfm) while operating on almost exclusively the feed of 165,000 gallons of concentrated flush manure per day. Given prior analysis that scaling and efficiency issues related to water scrubbing/compression systems for production of RNG optimize roughly at or near a 500 cfm, it became apparent that a first necessary step for RNG conversion would be to raise overall gas production on the site. Co-digestion is a common practice with Frear et al (2011), via long-term monitoring of a commercial digester in Lynden, Washington, estimating that biogas production can be at least doubled through a 20-30% volumetric substitution with industrial food processing waste.

Table 5.1: RNG production by dairy size and substrate volume/strength (92% runtime)

Size [a]	10% Substrate [b]			20% Substrate			30% Substrate		
ft^3 biogas per minute	Low [c]	Med [d]	High [e]	Low	Med	High	Low	Med	High
1000 WCE	83.2	92.7	116.2	86.3	122.4	175.7	98.6	160.5	252.0
2000 WCE	153.3	185.4	232.9	172.4	244.8	351.5	197.1	321.0	504.0
5000 WCE	383.2	463.5	582.1	431.1	611.8	878.7	492.7	802.4	1259.9
10000 WCE	766.4	927.0	1164.3	862.2	1223.5	1757.3	985.4	1604.9	2519.9

[a] Assume 33 gallons manure/wet cow equivalent (WCE) per day (33k, 66k, 165k, and 330k base loads manure)
[b] Percent substrate refers to percent of total volume into the digester and assumed 64% CH_4 content
[c] Low refers to base load manure or other similar substrate methane productivities on the order of 2.1 ft^3 CH_4/gallon
[d] Med refers to substrates of medium biogas strength on the order of 6.5 ft^3 CH_4/gallon
[e] High refers to substrates of high biogas strength on the order of 13 ft^3 CH_4/gallon

Table 5.1 is a more detailed description of the effect various volumetric additions of low, medium, and high strength substrate addition can have on a dairy of varying size. DeRuyter operates its digester on approximately 5,000 wet cow equivalents (WCE), thus showing that by attaining 30% volumetric addition of low strength substrates or 20% of medium strength substrates, biogas production could be approximately doubled from its present performance and attain the desired range near to 500 cubic feet per minute.

Attaining substrate at a 20-30% volumetric rate will not be an easy task as, at 30% addition, this amounts to nearly 70,000 gallons of substrate per day. While many digesters on the northwest side of the state have had success attaining long-term and/or consistent contracts for substrates, even at notable tipping fees, the same is not true of the Basin, where urban processing facilities are not as near, demand for landfill disposal is not so tight, and where numerous other outlets for waste organics, such as animal feed or composting, exist. In addition, practical experience at digesters practicing co-digestion has shown that intensive reliance on high-energy substrates such as fats, oils, and greases (FOG) can lead to fatty accumulations both within the digester and outside of the digester in the liquid effluent and fiber product. This is due to the relatively long hydraulic retention time required for effective bio-degradation of long chain fatty acids that result from FOG, a processing time that is not easily overcome without pre-treatment with more expensive hydrolysis chambers or thermophilic digesters (Chen et al, 2005). Consequently, an assumption in our subsequent analysis is that not only will the DeRuyter project obtain reliable sources for medium/high strength substrate waste at or near a 30% volumetric addition, but that great care will be taken in obtaining substrates that control the overall FOG percentage to the lowest value possible. This is important to maintain the quality of the fiber products that now generate a substantial portion of the project's revenue and to minimize additional digestion capital and operation costs.

To adequately practice co-digestion at the elevated flow rates, the following infrastructure improvements and associated capital and/or operating costs have been implemented in Pro Forma analyses.

- Insertion and operation of an existing mechanical agitator into the first chamber length of the modified plug-flow reactor so that entering substrates, and in particular FOG, can be adequately mixed and processed. While the agitator already exists and therefore results in no added capital investment, it will require an additional 10 HP of parasitic electricity.
- Modification to the existing concentrating separators, which transform the 2% TS flush manure to 8% TS flow for the digester. By installing automated water wash systems to each of the screens it is anticipated that blinding of the screens will be effectively reduced, allowing for production of a near 10% TS flow to the digester. This is necessary, as the increased flow rate at the same TS content would negatively impact the tight 20-day hydraulic retention time (HRT) being used by the digester for effective bacterial growth. By increasing the TS content, the increased flow can be accommodated while not impacting the HRT. Cost for retrofit additions totals $15,000.
- While other infrastructure modifications for substrate addition were considered (i.e. separate substrate dosing pit with automated controls, new road and turnarounds), the cost of these changes was determined to exceed the benefit for the project. Therefore we believe that existing equipment and infrastructure will meet new demands.

Table 5.2 summarizes the impact the proposed changes and substrate addition have on both gas production and digester thermal draw. Note that all mesophilic digesters have thermal loads to the incoming feed so that adequate temperature can be maintained. Under the baseline scenario, heat recovery units within the CHP system provide the required digester heat. Under the RNG model, the biogas scrubbing and compression units identified for the project come with heat recovery capability and early thermal projections suggest that their thermal recovery capability (4.8 M BTU/hour) will be sufficient to meet thermal needs for the digester, even during the coldest winter months. Biogas production is estimated at a mean of 537 cfm with potentially wide fluctuations due to digester performance and substrate addition.

Table 5.2: Predicted impact of substrate addition on biogas production and thermal loads

	Biogas (cfm)	Thermal (M BTU/hour)
Current Operation (165,000 gallons/day)		
29F Winter		3.56
49 F Mean	269	2.56
69 F Summer		1.55
Substrate Operation (235,000 gallons/day)		
29F Winter		4.63
49 F Mean	537	3.32
69 F Summer		2.02

Design Alternatives

Scrubbing Technology

After biogas is produced from the AD process, it contains numerous non-methane containments, including water, carbon dioxide, and hydrogen sulfide. Depending on the composition of the substrate, the biogas could contain nitrogen, oxygen, ammonia, siloxanes, and other impurities that must all be removed from the methane to achieve pipeline quality gas. Table 5.3 compares the different technologies we evaluated for achieving pipeline quality gas, with specific details of the varying approaches summarized after the table. Raw biogas must be purified to meet the quality standards that are specified by major pipeline transmission and distribution companies. This standard fluctuates from 90% on up, depending on the company. For the DeRuyter dairy it was assumed that 95% pure methane is needed to achieve pipeline quality gas. It can contain up to two percent by volume of carbon dioxide and cannot contain more than three percent by volume of combined non-hydrocarbon gases.

Table 5.3: Summary of approaches and parameters

Parameter	PSA	Water Scrubbing	Organic Scrubbing	Chemical Scrubbing
Pre-cleaning needed	Yes	No	No	Yes
Working pressure (bar)	4 - 7	4 - 7	4 - 7	No Pressure
Methane loss	< 3 % / 6-10%	< 1 % / < 2%	2-4%	< 0.1%

Methane content in upgraded gas	> 96%	> 97%	> 96 %	> 99%
Electricity consumption (kWh/Nm3)	0.25	< 0.25	0.24-0.33	< 0.15
Heat requirement (C)	No	No	55 - 80	160
Control to nominal load	+/- 10-15%	50-100%	10-100%	50-100%

When the raw biogas exits the digesters it is saturated with water vapor. This vapor can be corrosive and can cause mechanical wear if the gas scrubbing system is not designed to handle the water. Water vapor may be removed prior to gas scrubbing using various condensation techniques, or depending on the technology, during the scrubbing process.

Hydrogen sulfide can be dealt with in two ways. First there is the option to add precipitation to the digester. A historically common approach, with considerable operating and maintenance cost, is to add Fe^{+2} or Fe^{+3} ions, in certain forms, to the digester, however there are other technologies, besides precipitation, that can also be used to clean hydrogen sulfide from the biogas. Active carbon, chemical absorption, and biological treatment are among these processes that were analyzed to remove hydrogen sulfide. *Active carbon* is often used when hydrogen sulfide content is less than 1 ppm. The carbon filter is impregnated with other elements to speed up the process and produce a higher quality gas. The filters must be replaced when saturated with hydrogen sulfide and, although this method is extremely simple, the cost is high due to the replacement of filters. *Chemical absorption* is the use of sodium hydroxide to clean biogas. This is a very technical process and requires a great deal of management due mainly to the use of a caustic solution. This method is only used when very large quantities of gas are being cleaned or when there is a high level of hydrogen sulfide. Even under these conditions, chemical absorption is not used widely in small-scale applications due to high-risk potential and high cost of the process. This method was widely used in sewage sludge treatment plants before precipitation became the standard. *Biological treatment* is the addition of *Thiobacillus* and *Sulfolobus* microorganisms for aerobic conversion to elemental sulfur. This process can be added to the digester or added as a filter after the digester. This method is widely used in other applications but not for pipeline quality gas due to the unsuitable traces of oxygen left behind by the microorganisms.

Pressure Swing Absorption

Another technology, Pressure Swing Absorption (PSA), uses a carbon-absorbing material. This process uses four to nine vessels that work in parallel. One vessel is filled and pressurized with raw gas and the carbon dioxide and hydrogen sulfide are absorbed into the carbon material. At that time the clean gas is released and the pressure is then dropped to release the carbon dioxide from the ion-absorbed material. Each vessel takes its turn to produce a relatively steady flow of gas. Once the hydrogen sulfide is absorbed in these filters it cannot be reversed. Absorption material must be replaced on a regular basis due to the hydrogen sulfide and the destruction of the material by water. Water vapor must be removed from the gas before it is treated in the PSA system.

Water Scrubbing
Water scrubbing is another form of gas upgrading. This technology is based on the principle that carbon dioxide has a higher solubility in water than methane. The raw gas is run against the flow of water, in a scrubbing vessel, which absorbs the carbon dioxide and all the other contaminates. The water containing the carbon dioxide and contaminates is run through a stripping vessel which allows the contaminating material to be stripped out of the water and released. Water scrubbing has been widely used in the industry and comes in a broad array of capacities and suppliers.

Organic Scrubbing
Organic scrubbing uses the same method as the water scrubbing with one major difference. Instead of water, organic solvent, such as polyethylene glycol, is used to absorb the contaminating material. Carbon dioxide has a higher solubility rate in polyethylene glycol than in water, which means that gas-cleaning plants can be smaller in size compared to water scrubbing. On the other hand, water is cheaper and more readily available than polyethylene glycol.

Chemical Scrubbing
Chemical scrubbing uses specific chemicals to absorb contaminates and has the lowest methane loss of all the technologies. This method can absorb the hydrogen sulfide but it is recommended to remove it before the chemical scrubbing process. This is done because of the added complexity of regenerating the chemicals to reuse for gas cleaning. This process is usually used in large-scale plants and must have highly trained individuals that work with the chemicals.

Membranes
Membranes are another form of gas upgrading technique. These membranes are permeable to carbon dioxide, water and ammonia. Hydrogen sulfide must be taken out before the membrane by using a carbon filter. This is considered the classic technique for gas upgrading but has the highest methane loss compared to other systems.

<u>Transportation</u>
Transportation, storage and the construction of a pipeline were all assessed to see which option was more feasible for getting RNG to market. There were two types of storage that were considered: onsite permanent storage and tube trailers. Onsite storage would be expensive, take up space, and another storage tank would be needed at the receiving end of the gas distribution. Tube trailers on the other hand have more advantages than disadvantages. Some advantages are mobility, storage, and the creation of a virtual pipeline. The only disadvantage is that one tube trailer cannot store as much methane as an onsite storage tank possibly could, but more than one tube trailer could be purchased.

American Strategies Group supplied Promus Energy with information on several different types of trailers, as well as the compression equipment specifications and filling options. The Titan module from Lincoln Composites and the ISO Container C340 from Integrated Compressed Natural Gas (ICNG) are composite tube trailers that use composite tanks instead of steel tanks. Composite tanks weigh less and have a much higher capacity than steel tanks. Although composite tanks are much more expensive than traditional steel tanks, their lack of weight makes them the more efficient choice, if the gas must be transported by truck. Table 5.4 provides a comparison of traditional steel tanks and the new composite tanks.

Table 5.4: Summary of transportation equipment

Storage Method	Number of tanks/trailer	Weight (Tanks, Frame, Trailer)	CNG Capacity	CNG Weight
50 bar TITAN module	**4**	**19,500 kg**	**10,064 SCM**	**7,380 kg**
3AAX-2900 (12.2 m)	10	35,930 kg	5,677 SCM	4,070 kg
Type II tank (12.2 m)	3	28,500 kg	6,700 SCM	4,913 kg
Type II tank (125 L)	162	33,750 kg	6,235 SCM	4,570 kg

ISO Container C340

Product	40-foot Three Tube ISO Container	
Length	40 feet	12.192 m
Width	8 feet	2.438 m
Height Container	8 feet	2.438 m
Weight of Container	~ 80,416 pounds	~ 36.5 MT
Tare Weight	~ 63,916 pounds	~ 29.0 MT
Net Weight (Payload)	~ 16,500 pounds (gas)	~ 7.5 MT (gas)
Operating Pressure	3600 psi	250 bar
Operating Temperature	-40F to 112F	-40C to 45C
Volume Gas (STP - CNG)	~ 280,000 ft^3 (975 ft^3 water volume)	~ 8,000 m^3 (27,600 L water volume)

Certifications - Pressure Vessels
Designed to ISO 11119-1:2002 Gas cylinders of composite construction -- Specification and test methods -- Part 1: Hoop wrapped composite gas cylinders and ASME Section VIII, Div 3 and Section X and Code Case 2390. Certified by American Bureau of Shipping (ABS).

Certifications - Container
Open tank container designed and manufactured to ISO Standards (*1496-3-4th Edition – 1995-03-01 Tank Containers)*, and certified by ABS or equivalent for international use under the Convention for Safe Container guidelines (CSC).

(ICNG, Scott Peterson)

Titan Module

Property	SI Units	English Units
Water Volume (@250 bar)	8530 L	2253 gallons

Operating Pressure	250 bar (@ 15C)	3600 psi (@ 59F)
Weight	2400 kg	5291 pounds
Diameter	1.08 m	42.6 in
Length	11.6 m	38 feet
Gas Capacity	2516 SCM	88,860 SCF
Tanks/module	4	4
Total water Volume	34,220 L	9,013 gallons
Operating Pressure	259 bar (@15C)	3600 psi (@ 59F)
Max Fill Pressure	325 bar (@15C)	4500 psi (@59F)
Module Dimensions	2.44m x 2.44m x 12.2m	8' x 8 ' x 40'
Module Weight (1bar)	14,500 kg	31,970 pounds
Gas Capacity	10,064 SCM	355,440 SCF
Gas Mass	7,380 kg	16270 pounds

(Lincoln Composites)

Pipeline

A part of the feasibility study was to size a pipeline from the DeRuyter dairy to the main Williams Wenatchee Lateral natural gas pipeline. The output pressure from the gas-cleaning unit is 110 psi and the pipeline was sized to run the gas 3.7 miles without additional compression. It was determined that in order to avoid expensive compression costs, the pipeline would need to be sized so that there would be enough pressure to push the RNG without having to pre-compress the RNG. This resulted in a pipeline design of three inches for transportation. Over sizing to a four-inch pipe would allow for other dairies to utilize the pipe without having to construct another pipeline, and it would slightly increase costs. Included in the appendices is an interactive Excel spreadsheet that sizes pipe based on inputs and summarizes the analysis.

Dispenser (Filling) Station

American Strategies Group (ASG) specializes in the development of virtual pipelines and fueling stations for compressed natural gas. This company has done extensive research on the different technologies for refueling stations, decompression cabinets for pipeline insertion, and compressors for the refueling stations. After the technology was analyzed, ASG supplied Promus Energy with detailed information on suppliers and different technologies, and recommended SAFE Technologies. SAFE has high-quality equipment at a competitive cost, and has more than 31 years of operational history and manufacturing, which allows them to have products that will fit any customer's needs. The equipment is also extremely efficient and well tested.

Drawing Package

Included in the appendices are the site layout and footings for the chosen gas cleaning unit. These drawings are intended for the construction of a new site pad, but DeRuyter may be able to use a pre-existing concrete pad and shelter that housed the CHP motors.

CONCLUSION

Scrubber

After extensive research and consideration of all the factors for this feasibility study, water-scrubbing technology comes to the top of the list, with the second choice being PSA scrubbing.

Water scrubbing was selected for many reasons. These include a longer life with less maintenance with few high-wear parts that must be replaced, and the fact that the technology takes care of all the contaminants without having to add other mechanisms to achieve pipeline quality gas. Although this is not the cheapest technology when it comes to capital cost, lower operation and maintenance costs over the life span of the project gave this choice the edge for this dairy application. Another factor that influenced the decision was the safety and reliability that water scrubbing supplies. No harsh chemicals or specific liquids must be bought, which is key when rural areas are the location of the gas-cleaning units.

Once the water scrubbing technology was chosen, the next task was to identify a supplier. Flotech Greenlane was one of the first to commercialize an extremely efficient product and has had the best track record with the technology. Although the company is based out of Sweden, all of the parts required are manufactured in the USA, which makes shipping cheaper and faster. The units are also modular and self-contained. This means it can be assembled and hooked up without any major engineering designs. Greenlane supplies everything that is needed to take raw biogas to pipeline quality, from the compressor to the flash tank. The units supply a heat recovery option that is efficient enough to heat the digester in place of the CHP engines that previously supplied heat. Not only do they supply a spare parts package, they also check assembly and make sure that the unit was assembled properly to make gas production efficient with as little down time as possible. They also offer a remote monitoring system, where they monitor the system to make sure gas is in spec and that all the pieces are working together. Greenlane has systems that are sized for small- to large-scale operations. This is critical because there is not a custom setup for each dairy that must be designed for the scrubber and all of its components. These units are complete and do not require a large amount of space to install. Greenlane has also been the quickest to respond with information and has had the best customer service record available.

The Greenlane unit named Rimu fits the DeRuyter digester best. It has an inlet condition that ranges from 155 cfm to 500 cfm, thus allowing for the projected flow as well as fluctuations. Table 5.5 provides a summary of the Rimu system.

Table 5.5: Summary of Rimu system

Rimu	Max Input	500 SCFM
Numbers are based on following assumptions		
1) Inlet Condition- 15.3 psia, 86 degrees F	a=Atmospheric Pressure	

2) Standard Conditions are defined as 60degF @ 14.7 psia		
Operation hours per Year	8350	Hours
Gas Produced per year	*150,801,000*	*SCF/year*
	1,190,502.88	*GGE/year*
	158,341,050,000	*BTU/year*
	158,341	*MMBTU/year*
Separated Gas: typical composition is 56% N_2, 29% CO_2, 14% O_2, 1% H_2O+H_2S. (Based off of 60/40 Methane to CO_2 ratio)		

<u>Heat recovery</u> = 144.1 Horsepower (Boiler) which is 4,819,510 BTU/hour

(Flotech)

<u>Transportation</u>

For the virtual pipeline, transportation, and gas-dispensing unit, American Strategies Group led Promus Energy in the right direction. Out of the tube trailers that were supplied, the ISO container was chosen over the Titan container. The ISO was the cheaper of the two composite tank companies and gave it the edge over Titian since the companies have the same composite technology. SAFE was the company of choice for the gas dispenser unit, decompression cabinet, and the compressor. Their technologies were designed to work together which eliminates most of the engineering risk that would come with piecing these technologies together from different companies. The model of compressor chosen from SAFE is the S963. This compressor will be able to process 360,000 cubic feet of biogas per day. SAFE paired this compressor with a dispenser that has two hoses set up for fast fill applications. Along with choosing the compressor and filling station, a decompression cabinet was chosen to take the 3600 psi biogas and decompress it down to pressures suitable for pipeline injection. After analyzing the performance, cost, and support of the different companies and technologies, we selected the best-fit applications for the DeRuyter dairy project.

References

Websites for various technology providers were accessed for summary and technical information.

Acrona-Systems PSA (www.acrona-systems.com)
Air Liquide Membrane (http://www.airliquide.com)
CarboTech PSA, chemical absorption (http://www.carbotech.de)
Cirmac PSA, Chemical absorption, membrane (www.cirmac.com)
Flotech Sweden AB Water scrubber (www.flotech.com)
Gasrec PSA/Membrane (www.gasrec.co.uk)

GtS Cryogenic (www.gastreatmentservices.com)
HAASE Organic physical scrubbing (www.haase-energietechnik.de)
Läckeby Water Group AB Chemical absorption (www.lackebywater.se)
Malmberg Water Water scrubber (www.malmberg.se)
MT-Energie Chemical absorption (www.mt-energie.com/)
Prometheus Cryogenic (www.prometheus-energy.com)
Terracastus Technologies Membrane (www.terracastus.com)
Xebec (QuestAir) PSA (www.xebecinc.com)

Chapter Six — RNG Economic Analysis

INTRODUCTION

Chapters 4 and 5 have described in detail the market opportunities as well as technology choices and assumptions related to DeRuyter conversion from CHP to RNG. In this chapter, all of the information is put together to develop a Pro Forma for the RNG Options identified in Chapter 3. Key assumptions made during development of the pre-tax cash flow Pro Forma (2012-2032) include:

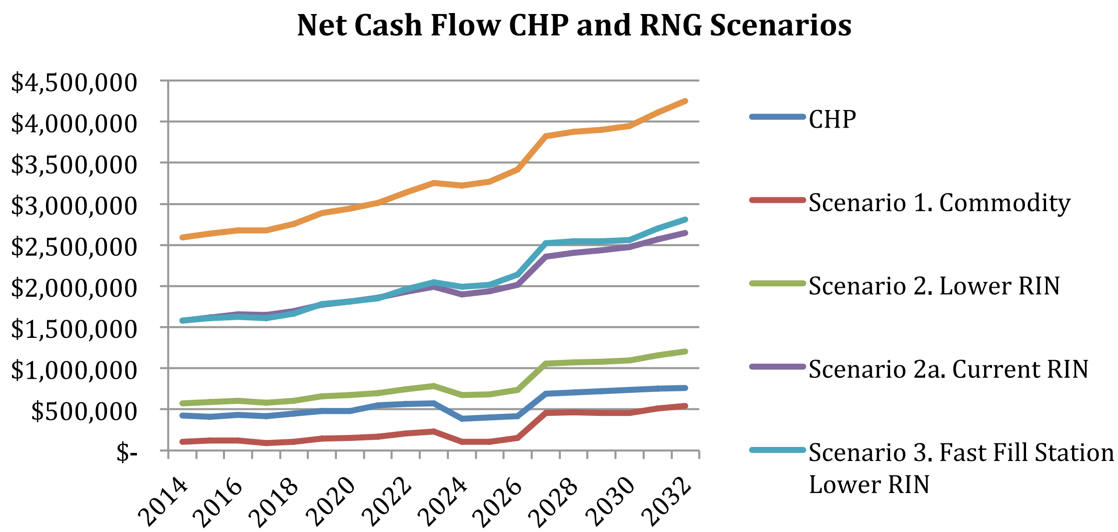
- **Substrate**. Addition of up to 70,000 gallons per day of medium- to high-energy substrate to maximize gas production around the 500 cfm level.
- **Renewable Fuel Standards Credits (RINs)**. RNG revenues are maximized if the RNG is distributed as transportation fuel generating RINs. This analysis assumes that DeRuyter controls the RNG and receives 100 percent of the RIN value. A sensitivity analysis is provided for reduced capture of the RIN value.
- **RNG Production**. RNG production is assumed to commence in 2014, allowing for project development, although discussion on this timeline is given in more detail in Chapter 9.
- **Financing**. This analysis assumes a 20-year loan at 7 percent interest. Although the dairy had 1 percent financing for its digester project, this may not be available for this additional investment. A sensitivity analysis is provided for lower interest rate financing.
- **RNG Transport**. Two alternatives were considered for transporting the gas from the digester site to a point of interconnection with the natural gas grid - by pipeline or by tube trailer.

Revenue Alternatives. Three revenue scenarios were reviewed:

- **Scenario 1 Commodity Value.** DeRuyter receives the commodity price of natural gas with no RIN value. This results in pre-tax cash flow that is less than the pre-tax cash flow from the existing CHP operation.
- **Scenario 2 RIN Value.** The RNG is sold as transportation fuel generating RIN values in addition to the commodity value. Two RIN values are analyzed.
- **Scenario 3 Fast Fuel Station.** The RNG is used as transportation fuel generating RIN values and is dispensed at a fast fuel station operated by DeRuyter.

Figure 6.1 below shows the pre-tax cash flow from the current CHP operation and the RNG scenarios. Revenues in all scenarios are the same for fiber and nutrient sales (medium price fiber and nutrient sales revenue). Carbon credit revenue is decreased because the total credits are reduced from 21,063 MT under the CHP operation to 17,495 MT under the substrate operation. The reduction in revenue is $35,000 per year through 2022.

Figure 6.1: Comparison of the RNG scenarios with baseline CHP



Specific details and quantitative conclusions from the cash flow summaries for the respective scenarios are:

- **Scenario 1 Commodity Value**. Cash flow under this scenario is less than the current CHP operation cash flow. In 2014, the difference is $322,000 less cash flow and in 2032 the difference is $217,000 less.
- **Scenario 2 RIN Value**. Cash flow under this alternative is higher than for the current CHP operation. With the lower RIN value, cash flow is $141,000 higher in 2014 and in 2032 it is $444,000 higher. With the current RIN value, cash flow is $1.15 million better in 2014 and in 2032 it is $1.9 million better.
- **Scenario 3 Fast Fuel Station**. Cash flow under this alternative is greater than under any other scenario. With the lower RIN value, cash flow is $1.15 million better in 2014 than the current CHP operation and $2.0 million better in 2032. With the higher RIN value, cash flow is $2.2 million better in 2014 and $3.5 million better in 2032 than the current CHP operation.

REVENUES

RNG revenues are more difficult to estimate than electricity sales revenue because under existing federal law, natural gas utilities, unlike electrical utilities, are not required to purchase gas from small producers and such sales are not subject to regulation by the WUTC. RNG revenues are estimated as: commodity prices, RINs, and retail fast fill station prices.

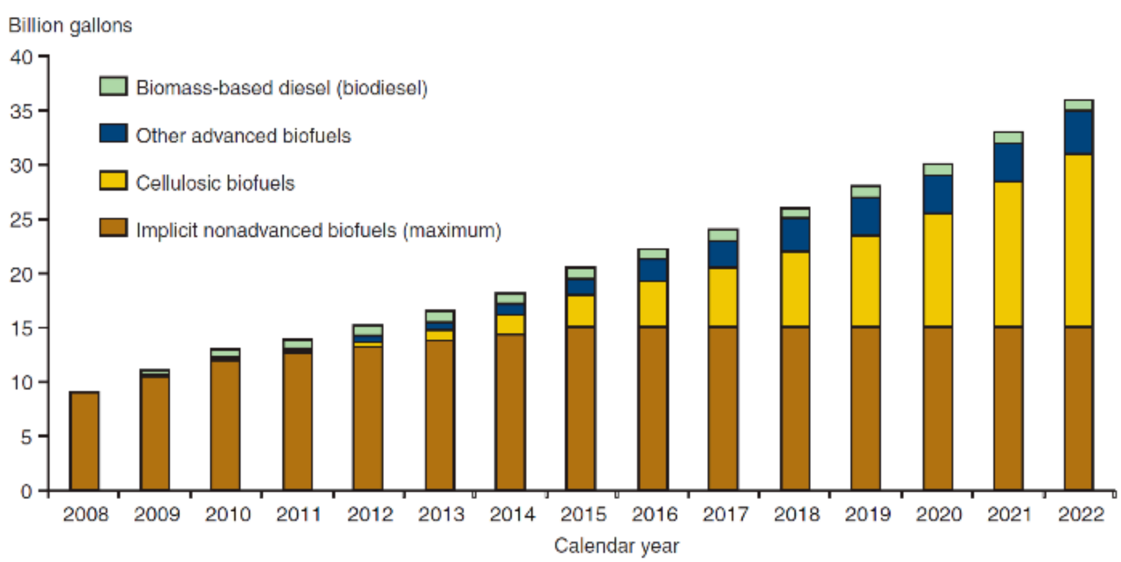
Commodity Price

National forecasts by the U.S. Energy Information Administration (EIA) project a stable and growing source of domestic natural gas supply with relative price stability, largely as the result of the discovery of substantial new supplies of shale gas in the Mountain West, the South and throughout the Northeast's Appalachian Basin. This results in relatively low projected commodity prices for natural gas. This analysis assumes that DeRuyter receives the Sumas Cascade commodity price (i.e. the wholesale price for gas at the border between Washington and Canada) for its gas. The Sumas Cascade price was estimated based on the March 2012 EIA forecast for prices at the Henry Hub reduced by the projected difference between the Henry Hub price and the Sumas Cascade Price in the Cascade Natural Gas 2011 Integrated Resource Plan. Under this analysis, the Sumas Cascade price forecast is \$3.87 per MMBTU in 2014 increasing to \$6.07 per MMBTU in 2032, resulting in revenues of \$613,000 in 2014 increasing to \$961,000 in 2032.

Renewable Fuel Standard Credits/RINs

The 2005 Energy Policy act created the first Renewable Fuel Standard (RFS). RFS2, the current version of this standard, requires 15.2 billion gallons of renewable fuel be created or imported into the United States by 2012, and 36 billion gallons by 2022 when the mandates expire. Specific carve-outs for the amount of advanced biofuels (renewable fuel other than ethanol from corn starch), cellulosic biofuels (from cellulose, hemicelluloses or lignin from renewable biomass) and biodiesel (fuel from renewable biomass) are included. These fuels must make up a greater portion of the renewable fuel in the United States over time, as illustrated in Figure 6.2.

Figure 6.2: RFS mandate 2008-2022 (McPhail et al, 2011)



Biogas that is captured at manure digesters, landfills and sewage and waste treatment plants, cleaned, compressed and used to fuel vehicles qualifies as an “advanced biofuel” under the RFS2 (blue bar in Figure 6.2). Just as digester projects that make electricity can sell the renewable benefit of this electricity, digester projects that make transportation fuel can sell the biofuel benefit of this fuel to producers and importers that have to demonstrate that a certain portion of their fuel qualifies as an “advanced biofuel” under the RFS2.

In electricity projects, Renewable Energy Certificates (RECs) are used to ensure compliance with Renewable Portfolio Standards. For transportation fuel projects, Renewable Identification Numbers (RINs) are used to track compliance with the RFS2. When advanced biofuels are produced and used, RINs remain a separate commodity from the fuel itself. The DeRuyter project has the potential to earn RINs in the scenarios in which the project owns the equipment that cleans and compresses biogas and fuels vehicles. In the scenarios in which DeRuyter does not own this equipment, the project will not generate RINs directly. With appropriate contracts and monitoring systems in place, however, the owner of the fueling equipment who purchases the RNG from DeRuyter could generate RINs. In these scenarios, the project has instead been modeled to charge a “green premium” on the RNG sales to reflect the increased value the purchaser of the gas can realize.

Revenue from the sale of RINs depends upon the following three factors:

1. The price at which these RINs are sold;
2. The number of RINs generated by the project; and
3. The transaction costs associated with monitoring, verifying, and commercializing the RINs.

Data on the current price of Advanced Biofuel RINs was gathered from the Oil Price Information Service. In 2011, Advanced Biofuel RINs sold for between \$0.69-\$0.74/RIN, with an average price of \$0.715/RIN. In 2012, prices have been very similar, between \$0.69-\$0.75/RIN, with an average price of \$0.72/RIN. Market participants, however, warn that RIN prices are extremely volatile and difficult to predict; these historically high prices are a result of skepticism that the requirements for advanced biofuel can be met in the short term. If larger quantities of advanced biofuel were made available, prices would likely drop quickly. Ethanol production has greatly exceeded the requirements of the RFS2, so RINs from “non-advanced biofuels” like ethanol are currently trading for as low as \$0.02/RIN.

Given this historic volatility, current RIN prices for advanced biofuels were modeled under two pricing scenarios: the current RIN value and a more conservative value of \$0.25/RIN. This is similar to “mid” RIN price of \$0.20/RIN used by a recent Oregon study of bio-methane from wastewater treatment plants (Oregon Department of Energy, 2012). Market participants confirmed that this is likely a best guess for the long-term value of Advanced Biofuel RINs.

The DeRuyter project is currently anticipated to generate 150,801,000 SCF of bio-methane for transportation fuel per year; this is equivalent to 158,341 MMBTUs per year. As set out in the RFS2, every 77,000 BTUs of bio-methane is equivalent to 1 RIN. The project is therefore anticipated to generate 2,056,377 RINs per year. Although there is no mandate for purchasing RINs under the RFS after 2022, this analysis assumes if the RFS2 sunsets, another renewable fuel incentive will exist after 2022 and its value is assumed to be at least equivalent to the value of RINs. The project Pro Forma therefore includes RIN revenue over the entire project lifetime through 2032.

Transaction costs for generating RINs have been included in this analysis. To create a RIN the facility producing renewable fuel must be registered in the EPA Moderated Transaction System by a third-party engineer. On this EPA system, RINs are screened, registered and traded. Each RIN must be registered within four days from the time the fuel is created. While no third-party verification is required of each registered RIN facilities can be audited by the EPA. After discussions with a variety of market participants and brokers, the project Pro Forma estimates that the transaction costs associated with registering facilities, registering RINs, and contracting to sell the RINs will be equal to 10% of the value of the RINs under the "Conservative Price" scenario.

Putting it all together in the Pro Forma, RINs under both pricing options are assumed to inflate at a rate of 2 percent per year. Transaction costs start at $51,000 per year and also increase at 2 percent per year. RIN revenue net of transaction costs under the current advanced biofuel RIN pricing is $1.5 million in 2014 growing to $2.1 million in 2032. Under the lower pricing, revenue is $463,000 in 2014 growing to $661,000 in 2032.

Retail CNG Station Price

The current retail price of CNG in the Seattle area is $1.85/GGE. This analysis assumes that the price remains at $1.85/GGE in 2014 and changes at the same rate as changes in the Sumas Cascade commodity prices. Actual retail prices will be affected by the rate of introduction of CNG vehicles into the U.S. fleet, which may have a substantial affect on CNG prices. The potential of a "concerted U.S. policy effort to shift the transportation sector away from oil toward natural gas would significantly increase demand, and thus natural gas prices" (PacifiCorp IRP 2011, pg. 29). Retail revenues under this scenario are $2.2 million in 2014, increasing to $3.4 million in 2032.

Operation Costs

RNG Production Operating Expenses

Operating expense includes repair and maintenance, power, other costs, and labor. As shown in Table 6.1 below, total operating expenses in 2014 are $229,000.

Table 6.1: Operating costs of RNG

Gas Operation Cost 2014		%
Maintenance & Repair		
Digester	$ 23,210	
Gas Cleaning Unit	$ 17,675	
Sub-total Maintenance & Repair	*$ 40,885*	*18%*
Electricity		
Digester & Current Nutrient Recovery	$ 40,366	
Gas Cleaning Unit	$ 88,521	
Digester Modifications for Substrate	$ 5,256	
Sub-total Electricity	*$ 134,143*	*58%*
Labor (1 FTE)	*$ 34,310*	*15%*
Other Gas Cleaning Unit Costs		
Water	$ 1,772	
Lubrication Oil	$ 2,132	
Remote Monitoring	$ 16,200	
Sub-total Other Gas Cleaning Unit Costs	*$ 20,104*	*9%*
Total Operations Cost	**$ 229,442**	
2014 CHP Operation Cost	**$ 290,082**	

Annual operating expenses are projected to increase by 2 percent per year for inflation. The total cost of operation for RNG production is lower than the cost of operation with the CHP system. We also analyzed whether it would be cost effective to use the biogas produced to generate power for the digester, scrubber, and nutrient recovery system. The analysis showed that the reduction in RNG for sale would be approximately 30 percent, with the resulting loss of revenue higher than the electrical power savings even at the lowest commodity pricing. (For example, in 2014 the loss of commodity priced revenue would be $164,000 including reduced delivery charges while only $134,000 in electricity costs would be saved.)

RNG Transportation Off-Site Operation Costs

Operations cost for the two transportation alternatives are (inflated at 2 percent per year):

- **Pipeline.** Annual operations costs are $4,500 in 2014 for maintenance of the pipeline.
- **Tube Trailer.** Operations costs assume $1.00 per mile cost of transporting gas with a round-trip of 26 miles per day to the furthest injection point on the Port of Sunnyside property.

Fast Fill Station Operation Costs

Operating costs of 25 percent of revenue are assumed to cover ground lease, staffing, and repair and maintenance of the station.

CAPITAL COSTS AND DEBT SERVICE

Capital costs include:

- **Gas Cleaning Infrastructure**. These capital costs include modifying DeRuyter's anaerobic digester to accept substrate at the required volume and the cost of acquisition and installation of the gas-cleaning unit. Capital costs are offset by the sale of the two 600 kW generators currently owned by DeRuyter.
- **Transportation of Gas Off-Site.** Two capital costs are estimated. The first is for a 3.8-mile pipeline down Dekker Road to an injection point and the second is the cost of tube trailers to transport the gas.
- **Injection Point.** The cost of the injection point for injecting pipeline quality gas into the grid.
- **Fast Filling Station.** The cost of construction of a fast filling station on leased property, most likely on Port of Sunnyside property.

Assumptions for the capital costs are:

- **Gas Cleaning Unit**. The cost estimate is based on a Flotech RIMU biogas upgrading system. Construction and installation include an allowance for on-site supervision by the supplier ($120,000); and contractor installation (20 percent), and mobilization and insurance costs (4 percent). A design allowance of 5 percent is provided for any drawings that may be needed.
- **Sale of Existing Generators**. The generators cost $0.9 million new and are estimated to have a resale value of 10 percent.
- **Digester Modifications for Substrate**. The $15,000 cost to install screen washing is included in the capital estimate.
- **Pipeline**. Assumes construction of 3" pipeline by a general contractor. Williams Northwest estimate to construct the pipeline is $0.5 million more expensive. The cost could be reduced if farm labor were used to construct the pipeline.
- **Tube Trailer**. This cost estimate is for two floating pipeline trailers. Used trailers may be significantly less expensive, but pricing is time dependent. The trailers are USDOT approved with a capacity of 280,000 ft^3 at 3600 psi. A used tractor to pull the trailers is included.
- **Injection Point**. This cost estimate is based on Williams Northwest estimated cost of adding an injection point.

- **Fast Fill Station.** The cost estimate includes additional compression and construction of the station.
- **Contingency.** A 10 percent contingency is included.
- **Project Management.** A 4 percent cost of project management is included.

Capital costs are shown in Table 6.2 below. Total capital costs vary by which transportation option is chosen and, for Scenario 3, the additional cost of a fast fill station. The resulting capital costs and debt service by scenario are shown below. Capital costs range from $5.7 million to $4.9 million with debt service between $462,000 and $540,000 per year assuming 20-year 7 percent financing.

Table 6.2: Capital costs of RNG

		Transportation Alternatives		Injection Point	Fast Fill Station
	Gas Cleaning Infrastructure	Pipeline	Tube Trailer		
Gas Cleaning Equipment	$1,500,000				
Construction & Installation	$432,000		$43,125		$30,750
Spare Parts	$70,700				
Digester Modification	$15,000				
Sale of Existing Generators	-$90,000				
Pipeline Construction		$1,285,000			
Pipeline Right-of-Way		$55,000			
Pipeline Permitting		$85,000			
Tube Trailers			$640,000		
Tractor			$10,000		
Compression On-Site			$287,500		
Injection Point				$1,000,000	
Fast Fill Station					$30,000
Fast Fill Compression					$175,000
Project Management 4%	$80,708	$66,761	$45,775	$47,160	$11,118
Sales Tax	$158,213	$101,515	$76,679	$79,000	$18,624
Design Allowance (5%)	$96,600				
Contingency (10%)	$200,270	$142,500	$97,063	$100,000	$23,575
Total	**$2,463,491**	**$1,735,776**	**$1,200,142**	**$1,226,160**	**$289,067**

	Capital Cost	Debt Service/Year
Scenario 1 & 2 - Commodity and RIN Value		
With Pipeline	$5,425,427	$513,000
With Tube Trailer	$4,889,793	$462,000
Scenario 3 - Fast Fill Station		
With Pipeline	$5,714,494	$540,000
With Tube Trailer	$5,178,860	$489,000

Sensitivity Analysis

RIN Value

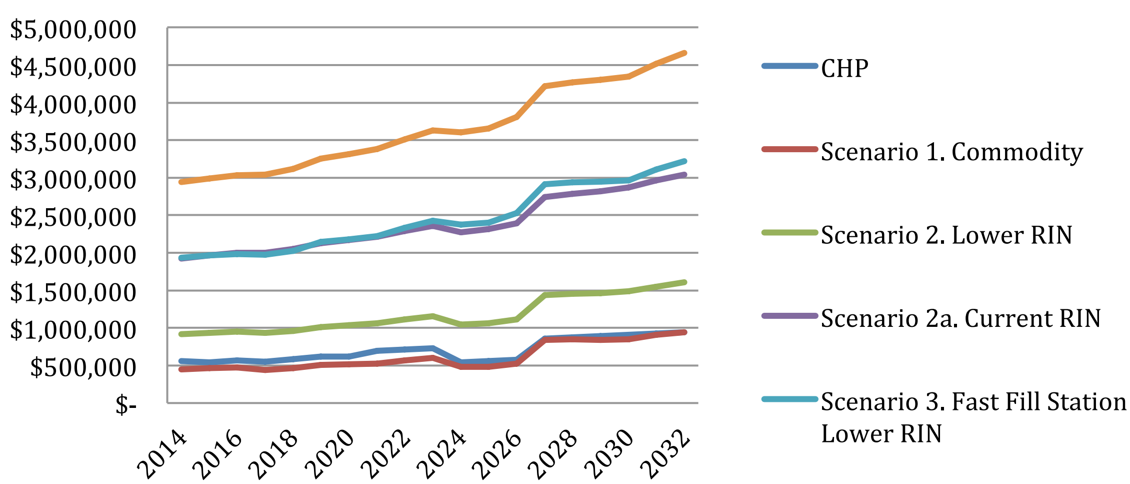
The Pro Forma assumes that DeRuyter captures 100 percent of the RIN value. This sensitivity analysis shows the impact if the RIN values are retained by DeRuyter at 0, 25, 50, and 75 percent of their value. The charts (Figure 6.4 as landscape set) below show that:

- **Scenario 2 RIN Value**
  - **Lower RIN Value –75 percent or more of the RIN Value Needed.** At the lower value of $0.25 per RIN, DeRuyter must receive at least 75 percent of the RIN value for this scenario to generate greater cash flow than the current CHP operation. At 75 percent, the increase over the CHP cash flow is very small - $18,000 in 2014 growing to $268,000 in 2032.
  - **Current RIN Value – 25 percent or more of the RIN Value Needed.** At the current value of $0.74 per RIN, DeRuyter must receive 25 percent or more the RIN value for this scenario to generate greater cash flow than the current CHP operation. At 50 percent, the increase over the CHP cash flow is $394,000 in 2014 increasing to $804,000 in 2032.
- **Scenario 3 Fast Fill Station – No RIN Value Needed.** At the lower and the current RIN value, the fast fill station scenario generates greater cash flow even if DeRuyter does not have any RIN revenue.

Interest Rate

The Pro Forma assumes a 7% interest rate on a 20-year loan. This analysis shows the impact if DeRuyter is able to secure the same 1% interest it had on the original digester investment. The change in rate would reduce expenses by ~$200,000 per year (Figure 6.3).

Figure 6.3: Sensitivity of interest rate



- **Commodity Value Scenario.** Even with 1 percent interest the commodity scenario does not generate more cash flow than the current CHP operation.
- **Other Scenarios.** The other RNG scenarios continue to generate more revenue than the current CHP model.

CONCLUSION

The RNG analysis is driven by two questions: at what price can RNG be sold and what are the logistics needed to get the RNG to high-value markets? A shift to natural gas also opens the door for RNG to displace petroleum in high-value motor fuel markets. RNG pricing was evaluated under three scenarios and compared to the current CHP model:

1. Commodity natural gas pricing: Even if sold at low wholesale prices for pipeline gas ($3.87/MMBTU or $0.44/GGE), RNG approximates net revenue under the CHP model.
2. Commodity plus "green premium" (RIN): When renewable credits are added to the commodity price of gas, RNG generates more net revenue than CHP; gas utilities, brokers, and CNG retailers are potential purchasers at this pricing if DeRuyter receives at least 25 to 50 percent of the RIN values depending on the RIN value.
3. Retail CNG plus RIN: If producers take RNG to the retail CNG market, where CNG is now selling for $1.85 and up, it generates much more revenue than CHP, especially if credits are added. Even if credits are not added, this scenario still generates more cash flow than the current CHP model.

The logistics needed to access these markets – gas cleaning and compression, pipeline injection, tube trailers, fueling facilities – are capital intensive and, although they offer profitable scenarios, the debt, unreliability of green credits, and operational risk can impede adoption of the model. These impediments can be addressed by:

- Reducing the debt burden through equity partners/developers and/or non-recourse loans or grants.
- Sharing the cost of common infrastructure through a cooperative, a public "host", or private development.
- Diversifying AD-related revenue streams and developing an integrated systems approach that, based on site-specific factors, can include revenue from energy, nutrients, fiber, CO_2, green credits, and other waste-to-revenue products.

Table 6.3: Pro Forma

	2014	2015	2016	2017	2018	2025	2030
Scenario 1. Commodity							
Revenue							
Natural Gas	$ 612,629	$ 616,146	$ 618,806	$ 624,115	$ 639,773	$ 799,909	$ 881,946
RIN							
Carbon Credit	$ (35,253)	$ (35,245)	$ (35,236)	$ (35,227)	$ (35,218)		
Total Revenue	**$ 577,376**	**$ 580,902**	**$ 583,570**	**$ 588,888**	**$ 604,555**	**$ 799,909**	**$ 881,946**
Operations Expense							
Scrubber & Digester	$ 229,442	$ 233,677	$ 238,351	$ 243,118	$ 247,980	$ 284,851	$ 314,498
Dekker Road Pipeline or	$ 4,500	$ 4,590	$ 4,682	$ 4,775	$ 4,871	$ 5,595	$ 6,178
Tube Trailer Transportation							
Injection (Delivery Charge)	$ 64,920	$ 64,920	$ 64,920	$ 70,113	$ 70,113	$ 81,780	$ 95,388
Fast Fill Station							
Total Operations Expense	**$ 298,861**	**$ 303,187**	**$ 307,952**	**$ 318,006**	**$ 322,964**	**$ 372,226**	**$ 416,065**
Net Income	**$ 278,515**	**$ 277,715**	**$ 275,618**	**$ 270,882**	**$ 281,591**	**$ 427,683**	**$ 465,882**
Debt Service	$ (513,000)	$ (513,000)	$ (513,000)	$ (513,000)	$ (513,000)	$ (513,000)	$ (513,000)
Scrubber & Digester	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)
Dekker Road Pipeline or	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)
Tube Trailer Transportation							
Injection	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)
Fast Fill Station							
Total Debt Service	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**
Net Cash Flow (Pre-Tax)	**$ (234,485)**	**$ (235,285)**	**$ (237,382)**	**$ (242,118)**	**$ (231,409)**	**$ (85,317)**	**$ (47,118)**
Alternative - Tube Trailer Transportation							
Change Operations Cost	$ (9,990)	$ (10,190)	$ (10,394)	$ (10,601)	$ (10,813)	$ (12,421)	$ (13,714)
Change Debt Service	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000
Total Change	$ 41,010	$ 40,810	$ 40,606	$ 40,399	$ 40,187	$ 38,579	$ 37,286
Alternative Net Cash Flow (Pre-Tax)	**$ (193,475)**	**$ (194,475)**	**$ (196,775)**	**$ (201,720)**	**$ (191,222)**	**$ (46,738)**	**$ (9,832)**
Scenario 2. RIN							
Revenue							
Natural Gas	$ 612,629	$ 616,146	$ 618,806	$ 624,115	$ 639,773	$ 799,909	$ 881,946
RIN (Lower RIN Value)	$ 462,685	$ 471,938	$ 481,377	$ 491,005	$ 500,825	$ 575,290	$ 635,167
Carbon Credit	$ (35,253)	$ (35,245)	$ (35,236)	$ (35,227)	$ (35,218)	$ -	$ -
Total Revenue	**$ 1,040,061**	**$ 1,052,840**	**$ 1,064,948**	**$ 1,079,893**	**$ 1,105,380**	**$ 1,375,200**	**$ 1,517,113**
Natural Gas	$ 612,629	$ 616,146	$ 618,806	$ 624,115	$ 639,773	$ 799,909	$ 881,946
RIN (Current RIN Value)	$ 1,470,309	$ 1,499,715	$ 1,529,710	$ 1,560,304	$ 1,591,510	$ 1,828,145	$ 2,018,420
Carbon Credit	$ (35,253)	$ (35,245)	$ (35,236)	$ (35,227)	$ (35,218)	$ -	$ -
Total Revenue	**$ 2,047,686**	**$ 2,080,617**	**$ 2,113,280**	**$ 2,149,192**	**$ 2,196,065**	**$ 2,628,054**	**$ 2,900,366**
Operations Expense							
Scrubber & Digester	$ 229,442	$ 233,677	$ 238,351	$ 243,118	$ 247,980	$ 284,851	$ 314,498
Dekker Road Pipeline or	$ 4,500	$ 4,590	$ 4,682	$ 4,775	$ 4,871	$ 5,595	$ 6,178
Tube Trailer Transportation							
Injection (Delivery Charge)	$ 64,920	$ 64,920	$ 64,920	$ 70,113	$ 70,113	$ 81,780	$ 95,388
Fast Fill Station							
Total Operations Expense	**$ 298,861**	**$ 303,187**	**$ 307,952**	**$ 318,006**	**$ 322,964**	**$ 372,226**	**$ 416,065**
Net Income Lower RIN	**$ 741,200**	**$ 749,653**	**$ 756,996**	**$ 761,887**	**$ 782,416**	**$ 1,002,973**	**$ 1,101,049**
Net Income Current RIN	**$ 1,748,824**	**$ 1,777,430**	**$ 1,805,328**	**$ 1,831,186**	**$ 1,873,101**	**$ 2,255,828**	**$ 2,484,301**
Debt Service							
Scrubber & Digester	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)
Dekker Road Pipeline or	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)
Tube Trailer Transportation							
Injection	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)
Fast Fill Station							
Total Debt Service	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**	**$ (513,000)**
Net Cash Flow (Pre-Tax) Lower RIN	**$ 228,200**	**$ 236,653**	**$ 243,996**	**$ 248,887**	**$ 269,416**	**$ 489,973**	**$ 588,049**
Net Cash Flow (Pre-Tax) Current RIN	**$ 1,235,824**	**$ 1,264,430**	**$ 1,292,328**	**$ 1,318,186**	**$ 1,360,101**	**$ 1,742,828**	**$ 1,971,301**
Alternative - Tube Trailer Transportation							
Change Operations Cost	$ (9,990)	$ (10,190)	$ (10,394)	$ (10,601)	$ (10,813)	$ (12,421)	$ (13,714)
Change Debt Service	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000
Total Change	$ 41,010	$ 40,810	$ 40,606	$ 40,399	$ 40,187	$ 38,579	$ 37,286
Alternative Net Cash Flow Lower RIN (Pre-Tax)	$ 269,210	$ 277,464	$ 284,602	$ 289,285	$ 309,602	$ 528,552	$ 625,334
Alternative Net Cash Flow Current RIN (Pre-Tax)	$ 1,276,834	$ 1,305,241	$ 1,332,934	$ 1,358,584	$ 1,400,288	$ 1,781,406	$ 2,008,587

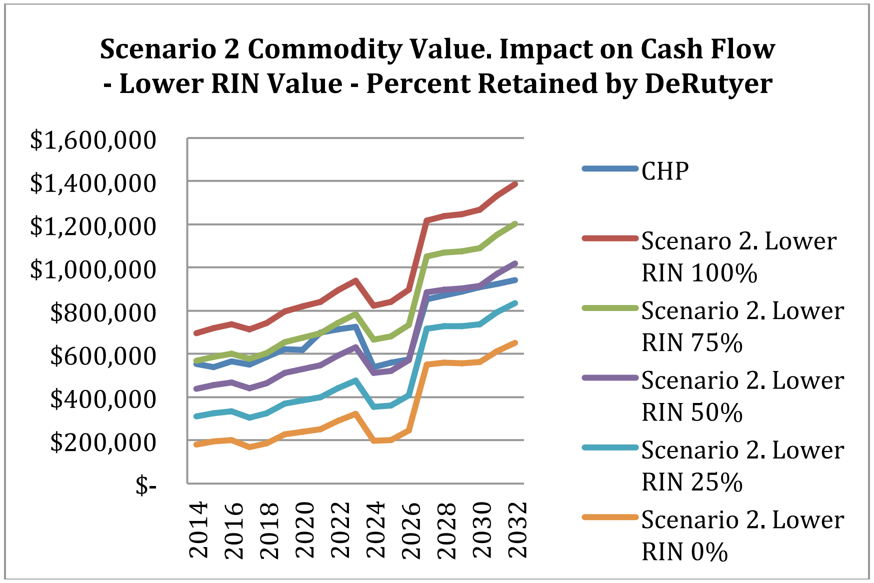
	2014	2015	2016	2017	2018	2025	2030
Scenario 3. Fast Fill Retail Station							
100% Transportation Use							
Pipeline Transportation to Injection Point							
Injection to Main Pipeline							
Fast Fill Station							
Revenue							
Natural Gas	$ 2,202,430	$ 2,215,074	$ 2,224,637	$ 2,243,723	$ 2,300,014	$ 2,875,710	$ 3,170,636
RIN Lower	$ 462,685	$ 471,938	$ 481,377	$ 491,005	$ 500,825	$ 575,290	$ 635,167
Carbon Credit	$ (35,253)	$ (35,245)	$ (35,236)	$ (35,227)	$ (35,218)	$ -	$ -
Total Revenue	**$ 2,629,862**	**$ 2,651,768**	**$ 2,670,778**	**$ 2,699,500**	**$ 2,765,621**	**$ 3,451,000**	**$ 3,805,803**
Revenue							
Natural Gas	$ 2,202,430	$ 2,215,074	$ 2,224,637	$ 2,243,723	$ 2,300,014	$ 2,875,710	$ 3,170,636
RIN Current	$ 1,470,309	$ 1,499,715	$ 1,529,710	$ 1,560,304	$ 1,591,510	$ 1,828,145	$ 2,018,420
Carbon Credit	$ (35,253)	$ (35,245)	$ (35,236)	$ (35,227)	$ (35,218)		
Total Revenue	**$ 3,637,486**	**$ 3,679,545**	**$ 3,719,111**	**$ 3,768,800**	**$ 3,856,306**	**$ 4,703,855**	**$ 5,189,056**
Operations Expense							
Scrubber & Digester	$ 229,442	$ 233,677	$ 238,351	$ 243,118	$ 247,980	$ 284,851	$ 314,498
Dekker Road Pipeline or	$ 4,500	$ 4,590	$ 4,682	$ 4,775	$ 4,871	$ 5,595	$ 6,178
Tube Trailer Transportation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Injection (Delivery Charge)	$ 64,920	$ 64,920	$ 64,920	$ 70,113	$ 70,113	$ 81,780	$ 95,388
Fast Fill Station	$ 550,608	$ 553,768	$ 556,159	$ 560,931	$ 575,003	$ 718,928	$ 792,659
Total Operations Expense	**$ 849,469**	**$ 856,955**	**$ 864,111**	**$ 878,937**	**$ 897,968**	**$ 1,091,154**	**$ 1,208,724**
Net Income Lower RIN	**$ 1,780,393**	**$ 1,794,812**	**$ 1,806,667**	**$ 1,820,563**	**$ 1,867,653**	**$ 2,359,846**	**$ 2,597,080**
Net Income Current RIN	**$ 2,788,017**	**$ 2,822,590**	**$ 2,854,999**	**$ 2,889,863**	**$ 2,958,338**	**$ 3,612,701**	**$ 3,980,332**
Debt Service							
Scrubber & Digester	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)	$ (233,000)
Dekker Road Pipeline or	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)	$ (164,000)
Tube Trailer Transportation							
Injection	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)	$ (116,000)
Fast Fill Station	$ (28,000)	$ (28,000)	$ (28,000)	$ (28,000)	$ (28,000)	$ (28,000)	$ (28,000)
Total Debt Service	**$ (541,000)**	**$ (541,000)**	**$ (541,000)**	**$ (541,000)**	**$ (541,000)**	**$ (541,000)**	**$ (541,000)**
Net Cash Flow (Pre-Tax) Lower RIN	**$ 1,239,393**	**$ 1,253,812**	**$ 1,265,667**	**$ 1,279,563**	**$ 1,326,653**	**$ 1,818,846**	**$ 2,056,080**
Net Cash Flow (Pre-Tax) Current RIN	**$ 2,247,017**	**$ 2,281,590**	**$ 2,313,999**	**$ 2,348,863**	**$ 2,417,338**	**$ 3,071,701**	**$ 3,439,332**
Alternative - Tube Trailer Transportation							
Change Operations Cost	$ (9,990)	$ (10,190)	$ (10,394)	$ (10,601)	$ (10,813)	$ (12,421)	$ (13,714)
Change Debt Service	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000	$ 51,000
Total Change	$ 41,010	$ 40,810	$ 40,606	$ 40,399	$ 40,187	$ 38,579	$ 37,286
Alternative Net Cash Flow (Pre-Tax) Lower RIN	**$ 1,280,403**	**$ 1,294,623**	**$ 1,306,273**	**$ 1,319,962**	**$ 1,366,840**	**$ 1,857,425**	**$ 2,093,366**
Alternative Net Cash Flow (Pre-Tax) Current RIN	**$ 2,288,027**	**$ 2,322,400**	**$ 2,354,606**	**$ 2,389,261**	**$ 2,457,525**	**$ 3,110,280**	**$ 3,476,618**

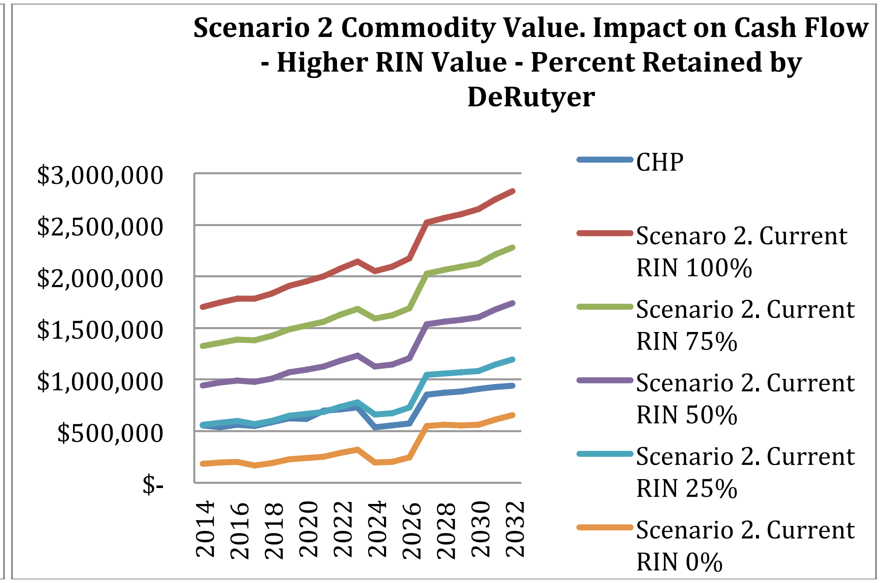
References

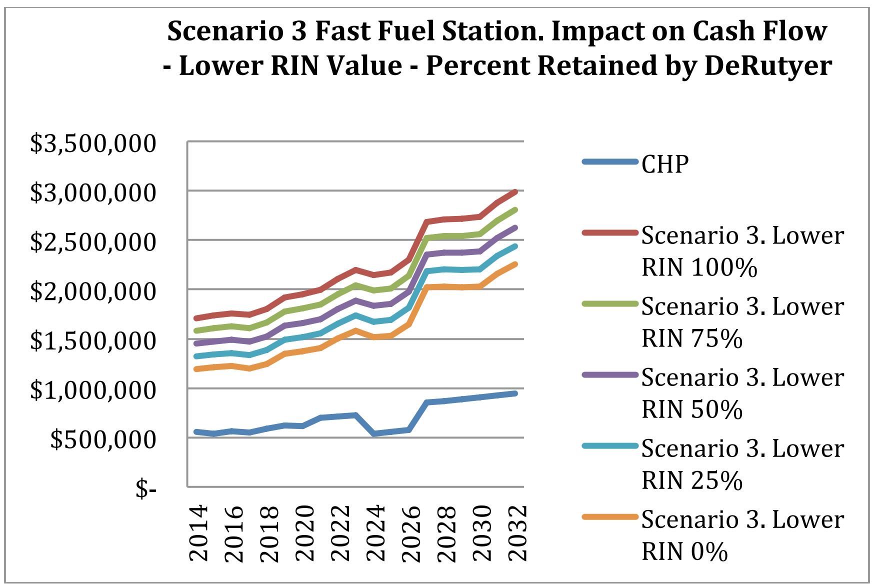
McPhail, Lihong et al. (2011). The Renewable Identification Number System and U.S. Biofuel Mandates. United States Department of Agriculture, Economic Research Service. BIO-03. November 2011.

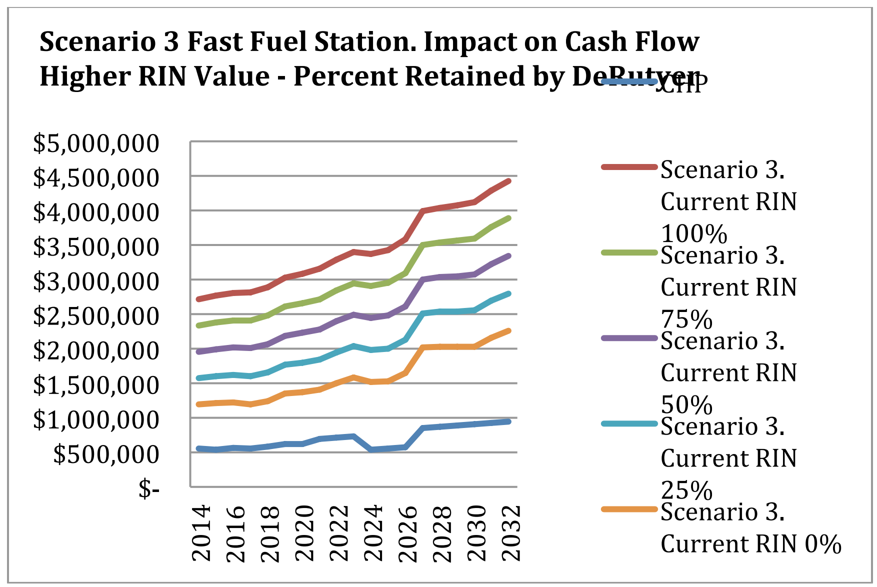
Oregon Department of Energy (2012) Bioenergy Optimization Assessment at Wastewater Treatment Plants. Oregon Department of Energy. March 20, 2012.

Figure 6.4: Sensitivity of RIN









Chapter Seven — Nutrient Recovery

INTRODUCTION

Every year, each cow generates 1,350 kg volatile solids (VS), 60 kg total nitrogen (N), 30 kg ammonia (NH_3), and 7 kg total phosphorus (P) (ASAE, 2005). Manure VS and NH_3 can result in odors, air quality, and health concerns, with 81% of all NH_3 emissions in the U.S. directly attributable to concentrated animal feeding operations (CAFOs) (Battye et al., 1994). Pathogens in dairy manures have also been implicated as contaminants of agricultural products (Grewal et al., 2006). Liquid manure is expensive to transport (Heathwaite et al., 2000) so manure is generally land applied to nearby fields. Long-term manure application on these lands has resulted in excess N and P accumulation; 36% and 55% of AFO dairies are in a state of N and P overload, respectively (USDA-APHIS, 2004). This has contributed to problems in nitrate leaching, eutrophication, ammonia toxicity, nitrite carcinogenesis, and nitrate-induced blue baby syndrome (US-EPA, 1996). As a result, dairy owners identify nutrient issues as one of their most important environmental concerns, one with potentially negative economic impacts (Bishop and Shumway, 2009). Meanwhile, much of the world's cropped farmland is nutrient-deficient, requiring fossil fuel-based inorganic fertilizers whose production results in negative impacts to the climate (fossil fuel fertilizer results in 1.2% of global GHG emissions) (IPCC, 2007).

Unfortunately, AD adoption, which is touted by some as a nutrient management tool, simply does not resolve existing farm nutrient loading concerns, as the total amount of nutrients stays intact, with digestion merely converting a portion of organic material to inorganic form (N and P are not gasified or reduced in liquid concentration during digestion). Thus, AD in itself does little to alleviate CAFO concerns related to nutrient management and will do so only if additional units in series to AD are implemented whereby nutrients can be pulled out or partitioned from the main liquid stream.

Meanwhile, project developers are intensifying efforts to generate additional revenue through use and/or production of co-products. One approach that has been successful on many dairies is to accept off-farm organics and practice co-digestion, generating tipping fees for received material and producing additional biogas. Frear et al. (2011) showed that biogas production could be doubled and total revenues tripled by incorporating off-farm organics at a rate of 20% of the volumetric manure flow. When off-farm organics are from local sources, considerable GHG mitigation can occur via their diversion from long-distance hauls to CH_4-releasing landfills (Murphy and McKeogh, 2004). However, co-digestion alone is insufficient to enhance adoption rates and GHG mitigation on CAFOs, as co-digestion exacerbates the aforementioned nutrient loading concerns. Frear et al. (2011) showed that even limited co-digestion caused 60% and 10%

increases in on-farm N and P in one case study. It is imperative then, from the perspective of AD adoption as well as environmental stewardship, to incorporate nutrient recovery technologies.

Three Nutrient Recovery Approaches Analyzed

Three nutrient recovery scenarios were evaluated. These were: (1) the existing screening/settling system which partitions and exports fiber and phosphorus-containing manure fines from the effluent in the form of high-value products within a CHP model; (2) incorporation of a struvite crystallization process within an RNG model for production and export of primarily phosphorus but some ammonia as value-added fertilizer; and (3) combined ammonia-stripping and phosphorous solids settling within an RNG model for production and export of two bio-fertilizers.

Phosphorus Containing Fine Solids

DeRuyter presently screens/settles fine solids and is now beginning to sell the product as a value-added fertilizer. While enhancements could undoubtedly be made, the system for now is working quite well, removing ~50% of total phosphorus from the effluent stream while using little in capital and operating costs. This nutrient recovery system, while doing little in regard to nitrogen removal and remediation of nitrate and ammonia concerns, is nonetheless rather effective at phosphorus control and, as discussed, already exists as a major part of the baseline CHP analysis.

Struvite

An emerging commercially viable P removal and recovery process is crystallization in the form of struvite (magnesium ammonium phosphate hexahydrate, or $MgNH_4PO_4 \cdot 6H_2O$) (Battistoni et al., 2006; Burns et al., 2001). Struvite formation requires that three soluble ions in the wastewater solution, Mg^{2+}, NH_4^+ and PO_4^{3-}, react to form precipitates with low solubility (pKsp of 12.6). The resulting struvite product can be marketed as a slow-release fertilizer and its crystalline structure formation is well suited to be produced in a crystallizer. Different types of crystallization reactors have been tested however, for purposes of this study, analysis was focused on anticipated use of a gas agitated fluidized bed reactor (Bowers and Westerman, 2005) developed by MultiForm Harvest (Seattle, WA).

Combined ammonia stripping and phosphorus settling

Project engineers at WSU, alongside their industrial partners (DVO Incorporated and Andgar Corporation), have patented and are now commercially demonstrating a unique combined ammonia stripping and phosphorus recovery system (Frear et al., 2010). The process uses high temperature (55^{o}C) limited, non-biological aeration to elevate pH and strip ammonia, producing ammonium sulfate solution as a saleable bio-fertilizer. Aeration also removes supersaturated CO_2 for downstream settling/dewatering of P-containing solids, thereby producing a second saleable product, phosphorus-rich fine solids, as well as a residual nutrient-reduced AD effluent. This partitioning of the nutrients allows for three different streams, each with its own fertilizer ratio, for optimal use on dairy soils or as a bio-fertilizer.

Struvite Process Design

Several factors can affect struvite precipitation, such as pH, super-saturation of the three ions in the solution, and the presence of impurities (e.g., calcium) (Doyle and Parsons, 2002; Nelson et al., 2003). For instance, calcium impurities, such as those present in synthesized wastewater, can negatively impact struvite formation because calcium-phosphorus precipitates can also be formed (Le Corre et al., 2005). Unfortunately, this has been shown to be the case when applying struvite technology to calcium-rich dairy manure with pilot studies showing less than 15% TP removal (Harris et al., 2008). The majority of the manure P used in their study was verified by X-ray diffraction (XRD), scanning electron microscopy, and elemental analysis, as being in the form of calcium phosphate, not struvite. These results suggested that struvite formation was inhibited by the calcium bond that Le Corre et al. (2005) predicted. Thus, the only way to produce struvite in a reliable manner, leading to effective and significant removal of phosphorus, is to first treat the AD effluent with acid so that, at the lower pH, these insoluble calcium salts can be made soluble, which upon later pH elevation and magnesium supplementation will then be available for struvite production.

Under the struvite scenario, the DeRuyter system will remove phosphorus from the back end of the settling weirs that presently exist and they will do so by dosing acid after the fiber separators but before the settling weir to reduce the pH from 8 to 5.5. This pH reduction will allow for phosphorus contained in solids to become dissolved so that struvite can be precipitated. It also allows for more effective settling of the solids in the settling weir, but this time it will not be P-solids for sale but simply low-P containing solids, mostly organic/inorganic material. After the settling weir, the liquid (now with correct pH, soluble P, and low suspended solids) will be treated in the struvite crystallizer (MultiForm Harvest) which needs input of soda to raise the pH again, magnesium to add in the missing amount of magnesium to facilitate proper struvite production, and electrical energy to run pumps, mixers, etc. The final product is drained from the bottom of the conical crystallizer and air dried to about 20 percent moisture for sale as a slow-release bio-fertilizer. The higher flow rate that will run through the digester due to additional substrate digestion (235,000 gallons/day) has been used as the flow design. Existing P concentrations as well as other concentrations of materials within the manure have been used for design purposes. Costs and performance have been estimated from previous pilot trials as well as scale up (0.6 scaling factor) of a design of a commercial system being installed in Pennsylvania.

Struvite Pro Forma Assumptions and Results

Under these assumptions, a DeRuyter struvite crystallizer can generate 1.65 tons of struvite per day once full operation is achieved. This financial analysis assumes that the struvite system becomes operational in 2014 and takes three years to achieve full production. Struvite is anticipated to sell for $150 per ton, with the sales rate remaining flat for the first three years and increasing 2 percent per year following that. Under this assumption total struvite revenue is $30,000 in 2014 increasing to $124,000 in 2032.

Table 7.1 shows the chemical inputs needed for the crystallizer and the initial weighted average cost of $311.00 per ton. The total cost of the chemicals is $748,000, which exceeds the total potential revenue.

Table 7.1: Chemical input costs for struvite system

Chemicals Required	Sulfuric acid	Caustic Soda	Magnesium Chloride	Weighted Average Cost
Tons/day	3.5	2	1.1	
Tons/year	1,278	730	402	
Price/ton (2014)	$ 200.00	$ 400.00	$ 500.00	$ 311.00
Total cost (2014)				$ 748,000

The struvite system requires 87,600 kWh of electricity a year. This analysis assumes that the electricity is purchased at the current rate of $0.06 per kWh resulting in an additional $5,000 in expense in 2014 growing with a 2 percent annual inflation rate to $7,500 in 2032. The capital cost for the struvite system is $485,000 including sales tax. Assuming 7 percent interest and a 20-year loan, the annual additional debt service cost is $46,000 per year (Table 7.2).

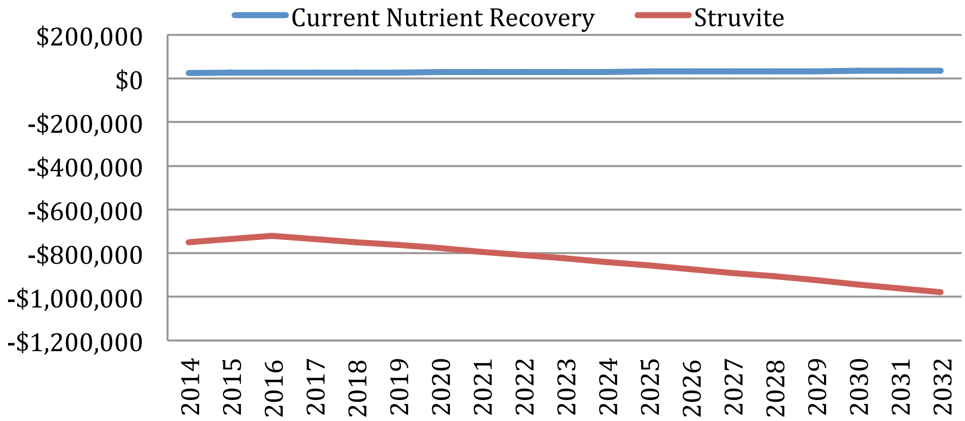
Table 7.2: Capital equipment for struvite system

Capital Cost of Struvite System	
Equipment and Construction	$450,000
Chemical Storage Tanks (3)	
Pretreatment Tank with pump/recycle agitation (1)	
Pre-Crystallizer Reactor (1)	
Main Crystallizer Reactor (1)	
Support structure for all above equipment	
Small electrical services building for switches, controls and storage	
Drying area	
Sales Tax	$35,550
Total	**$485,550**

The analysis shows that the operations cost of the struvite alternative, primarily the chemicals needed for the struvite crystallizer, exceed the potential revenue from struvite sales (Figure 7.1).

When combined with the additional debt service, the struvite option results in a negative cash flow of ($770,000) in 2014, the assumed first year of operation, growing to a negative cash flow of ($998,000) in 2032. Adding in the loss of revenue from the sale of nutrients under the current nutrient process increases the loss to ($795,000) in 2014 and to ($1.034 million) in 2032 with the lowest price assumption for fertilizer sales.

Figure 7.1: Cash flow comparison of existing P system and struvite system



Combined Ammonia Stripping and Phosphorus Settling Process Design

In the process design, it is assumed that DeRuyter has switched to a RNG model operating with 30% volumetric co-digestion of off-farm substrates, which will presumably increase the nutrient loading, particularly nitrogen loading, to the farm, thereby requiring a more serious review of nutrient recovery installation. As a first step, available thermal energy will be used to raise the temperature of the AD effluent within the existing digester effluent pit to 150F using heat exchangers. This heat treatment will allow for enhanced pathogen control of the entire flow, including fiber, in effect producing a Class A fiber product prior to compost operation. The remaining liquid after fiber separation will be sent to a specially designed micro-aeration plug-flow tank where carbon dioxide and ammonia gases will be stripped from the liquid. Importantly, the stripping of the carbon dioxide raises the pH and allows for more ready stripping of the ammonia without the need for chemical addition. Additionally, downstream release of the carbon dioxide allows for a more ready settling of phosphorus-containing solids in the existing settling weir system. The stripped gases will be sent to an acid contact tower where acid under pH control will produce an ammonia sulfate solution of approximately 38% concentration and pH near neutral. The stripped and settled liquid will then be sent to the existing lagoon for storage prior to land application. Based on pilot and demonstration results, it is anticipated that the system could recover 70% of the ammonia from the effluent, 50% of the total nitrogen, and 80% of the phosphorus, thereby significantly partitioning the nutrients away from the single lagoon liquid and into multiple streams.

Combined System Pro Forma Assumptions and Results

Table 7.3 is a summary of the capital equipment necessary for the installation of the system on the DeRuyter project using existing data from two demonstration sites presently under study. As can be seen, the capital infrastructure required is not insignificant, with the majority of the cost held in the equipment necessary to aerate and dose acid. It is assumed that the capital necessary is achieved through debt service using a 20-year loan at 7%, producing an annual debt payment of $203,000. Table 7.4 is a summary of the operating expenditures for the process. Beyond additional labor to maintain/operate this chemical plant is the daily addition of significant amounts of electricity and acid. It is assumed that electrical service is purchased from the grid as opposed to produced on site.

Table 7.3: Capital equipment for full nutrient recovery system

Capital Cost of Full Nutrient Recovery System	
Heat Exchanger in Effluent Pit plus Connect	$220,000
Modify Screens	$51,800
Aeration System	$798,400
Concrete Vessel	
Two blowers - 280 HP	
Micro-aerators	
Heat Exchangers	
Piping, misc.	
Acid Contact Tower with Controls	
Contact Tower	$283,000
Controls	
Storage Tanks (5, 10,000 gallon tanks)	
Acid Storage and Safeties	$18,000
Acid Tank - 10,000 gallons	
Safeties	
Settling Weir Modifications	$6,800
Re-pipe emergency overflow	
Electrical and controls	$183,000
Engineering, Permitting, & Excavation	$450,000
Misc. labor, hardware costs, contingency	$133,600
Total	**$2,144,600**

Table 7.4: Operating expenses for full nutrient recovery system

Operating Expenses Full Nutrient Recovery System	
Labor (0.5 FTE)	$17,848
Electrical (310 KW less downtime)($0.624/kWh)	$135,615
Sulfuric Acid (460 gallons/day at $220/ton) (2% increase)	$272,336
Maintenance (3% of capital cost estimate)	$64,338
Total per year less annual increase	**$490,137**

Multiple revenue streams result from the total nutrient recovery package. The revenues result from: (1) increased fiber production due to screens with tighter mesh openings (20% increase in production); (2) increased phosphorus-solids production due to aeration process (500 extra tons/year), plus potential increase in market value (10-20% increase) due to higher concentration of phosphorus and other nutrients; and (3) ammonium sulfate solution sales, either at retail ($424/ton) or wholesale value (50% off retail) from the 4.56 tons of product produced per day.

Table 7.5 summarizes the total revenue potential under three scenarios: (1) low -- increase in fiber production, increase in phosphorous solids pricing by 10% and wholesale price for ammonium sulfate; (2) medium -- increase in fiber, increase in phosphorous solids pricing by 10% and retail pricing for ammonium sulfate; and (3) high -- increase in fiber and solids production, increase in phosphorous solids pricing by 20% and retail pricing for ammonium sulfate.

Table 7.5: Three revenue scenarios for full nutrient recovery

	Fiber	P-Solids	AS Solution	Total
Scenario 1--Low	$62,399	$7,803	$294,329	$389,526
Scenario 2--Medium	$62,399	$7,803	$588,658	$683,855
Scenario 3--High	$62,399	$55,401	$588,658	$731,453

Below is a summary of the developed pre-tax 20-year Pro Forma for the combined nutrient recovery enterprise. As can be seen, under a net low revenue scenario, considerable negative cash flow results, while the medium and high scenarios result in cash neutral and positive cash flows, respectively (Table 7.6).

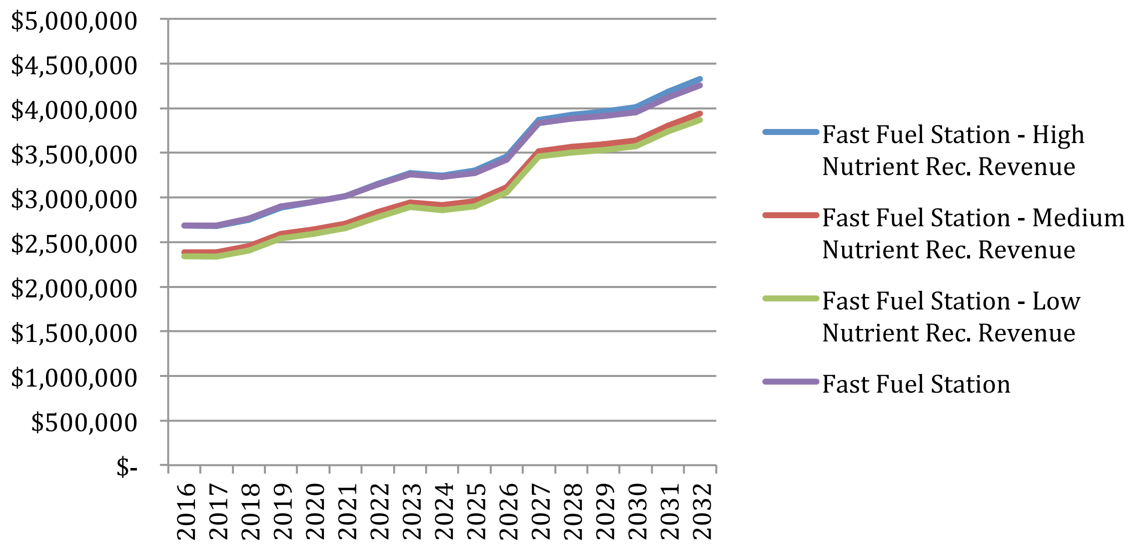
Table 7.6: Pro Forma for nutrient recovery enterprise

Revenue		2016	2017	2018	2019	2020	2025	2030
Fiber Sales Increase Volume (tons/year)	20%	8,400	8,400	8,400	8,400	8,400	8,400	8,400
Price/Ton	1.20	$7.43	$7.58	$7.73	$7.88	$8.04	$8.88	$9.80
Revenue Fiber		$62,399	$63,647	$64,920	$66,218	$67,543	$74,573	$82,334
Ammonium Sulfate Fertilizer (new product)					1.02 inflation			
Tons/day	4.56							
Tons/Year (92% operating time)	1,531	1,531	1,531	1,531	1,531	1,531	1,531	1,531
MT/Year		1,388	1,388	1,388	1,388	1,388	1,388	1,388
Retail Value MT		$424	$424	$424	$432	$441	$487	$538
Offset Farm Cost or		$588,658	$588,658	$588,658	$600,431	$612,440	$676,183	$746,561
Wholesale Value 50%		$294,329	$294,329	$294,329	$300,216	$306,220	$338,092	$373,281
Fertilizer Product 10% Increase in Value at Same Tons	1.10							
Medium Value - Fertilizer		$7,803	$7,959	$8,118	$8,281	$8,446	$9,325	$10,296
Fertilizer Product - 500 More Tons & 20% Increase In Value	1.20							
Additional Tons		500	500	500	500	500	500	500
Price -20% higher		$79.59	$81.18	$82.81	$84.46	$86.15	$95.12	$105.02
Revenue - additional tons		$39,795	$40,591	$41,403	$42,231	$43,076	$47,559	$52,509
Revenue -base production 20% price increase		$15,606	$15,918	$16,236	$16,561	$16,892	$18,651	$20,592
Total Fertilizer Product Added Value		$55,401	$56,509	$57,640	$58,792	$59,968	$66,210	$73,101
Carbon Credits - Additional Revenue								
Voluntary		$0	$0	$0	$0	$0	$0	$0
TCT Purchase		$0	$0	$0	$0	$0	$0	$0
Pre-Compliance		$0	$0	$0	$0	$0	$0	$0
High		$0	$0	$0	$0	$0	$0	$0
Total Revenue								
Low - 10% Increase in Fertilizer Value - Wholesale Ammonium Sulfate		**$364,531**	**$365,935**	**$367,367**	**$374,715**	**$382,209**	**$421,990**	**$465,911**
Medium - 10% Increase in Fertilizer Value - Retail Ammonium Sulfate		**$658,860**	**$660,264**	**$661,696**	**$674,930**	**$688,429**	**$760,081**	**$839,191**
High - 20% increase in Fertilizer Value + Increased Fertilizer Production Retail Ammonium Sulfate		**$706,459**	**$708,815**	**$711,218**	**$725,442**	**$739,951**	**$816,966**	**$901,996**
Operation Cost								
Labor .5 FTE	0.5	$17,848	$18,205	$18,569	$18,940	$19,319	$21,330	$23,550
Electricity								
kWh		2,172,480	2,172,480	2,172,480	2,172,480	2,172,480	2,172,480	2,172,480
$/kWh		$0.0624	$0.0637	$0.0649	$0.0662	$0.0676	$0.0746	$0.0824
Sub-total Electricity		$135,615	$138,327	$141,094	$143,916	$146,794	$162,072	$178,941
Maintenance 3% of capital		$64,788	$64,788	$64,788	$64,788	$64,788	$64,788	$64,788
Acid								
Gallons/day	480							
Gallons/year (92% run time)	161,184							
Pounds/Gallon	15.36							
Pounds/Year	2,475,786							
Tons/Year	1,238							
Price/ton	$220							
Cost per year	$272,336	$272,336	$277,783	$283,339	$289,006	$294,786	$325,467	$359,342
Total Operation Cost		**$490,587**	**$499,103**	**$507,789**	**$516,650**	**$525,687**	**$573,657**	**$626,621**
Debt Service		-$204,000	-$204,000	-$204,000	-$204,000	-$204,000	-$204,000	-$204,000
Net Low Revenue		**-$330,056**	**-$337,168**	**-$344,422**	**-$345,935**	**-$347,478**	**-$355,668**	**-$364,710**
Net Medium Revenue		**-$35,727**	**-$42,839**	**-$50,093**	**-$45,719**	**-$41,258**	**-$17,576**	**$8,570**
Net High Revenue		**$11,871**	**$5,711**	**-$572**	**$4,793**	**$10,264**	**$39,308**	**$71,375**

Comparison of nutrient recovery scenarios within entire RNG package

While numerous permutations exist for RNG scenarios in combination with nutrient recovery, for simplicity sake, Figure 7.2 compares the highest performing RNG scenario — Fast Fuel Station at the three different nutrient recovery revenue scenarios: high, medium and low. In this case, only the nutrient recovery scenario with high revenue estimates allows for a similar cash flow while the other two scenarios lead to an overall reduction. This outcome is due to the high capital and operating costs for the nutrient recovery package, thus precluding its inclusion in a project unless nutrient issues strongly proclaim its involvement. Additionally, time will be required to further demonstrate this nutrient recovery technology as well as other of its kind, as only now is application of nutrient recovery to farm-based projects beginning to be explored.

Figure 7.2: Fast fuel scenarios under high, medium and low nutrient recovery



Potential for additional environmental credits with nutrient recovery

When nitrogen is applied to cropland, a small portion of it is released as nitrous oxide (N_2O). Nitrous oxide is a potent greenhouse gas with 298 times the global warming potential of carbon dioxide. Reducing the amount of nitrogen applied to fields will subsequently reduce N_2O emissions (altering the source, rate, time and placement of application also impacts N_2O release). Through nitrogen recovery, the DeRuyter project has the opportunity to reduce the amount of nitrogen applied to nearby fields, and therefore reduce N_2O emissions and earn carbon credits.

The avoided methane carbon credits described earlier are an established project type in voluntary carbon markets, and will be one of the early project types accepted in California's regulatory market. Nutrient management is less mature. Protocols are emerging from the voluntary market that delineate what types of nutrient management projects qualify to generate carbon credits and then outline how to quantify these credits. The Michigan State University (MSU) methodology "Quantifying N_2O Emission Reductions in U.S. Agricultural Crops through N Fertilizer Rate Reduction" is in the final stages of approval under the Verified Carbon Standard, a voluntary registry in the United States. To date, no nutrient management projects have generated and registered carbon credits on any voluntary or regulatory registry. The price at which these carbon credits can be sold, however, is very difficult to anticipate. Because credits certified by the Verified Carbon Standard are purely voluntary, prices have been around $2-$4/credit. As new nutrient management protocols emerge from the Climate Action Reserve, American Carbon Registry, and the California Air Resources Board, however, credits could become more likely to count in California's regulatory market and, therefore, drastically increase in value to the \$8.50/credit, or even the \$15/credit, levels.

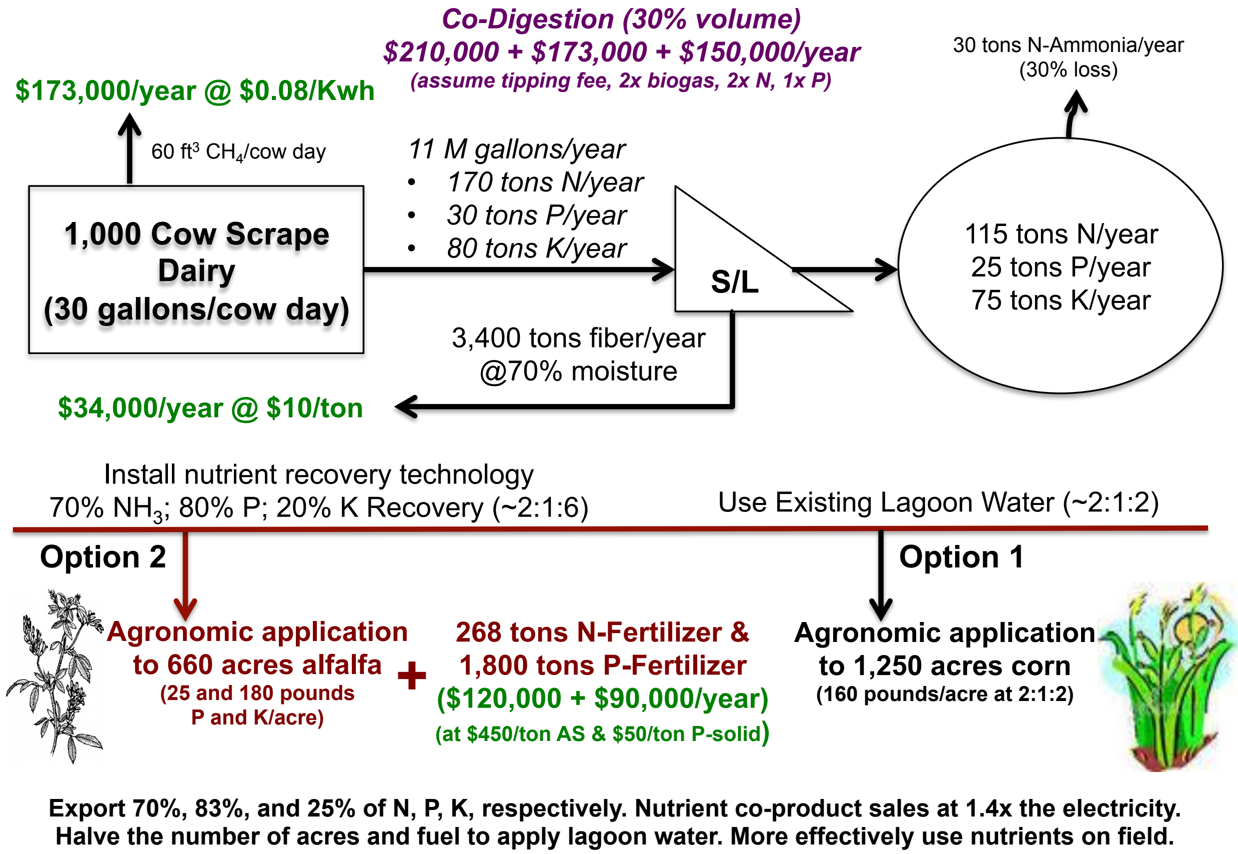
Figure 7.3: Estimated N_2O emission reduction and revenue projection

	2013	2014	2015	2020	2025	2030	2031	2032
Nutrient GHG Credits	1,224	1,224	1,224	1,224	1,224	1,224	1,224	1,224
Carbon Price- Voluntary	\$ 3.00	\$ 3.00	\$ 3.00	\$ 3.00	\$ 3.00	\$ 3.00	\$ 3.00	\$ 3.00
Carbon Price- TCT purchase	\$ 6.00	\$ 6.00	\$ 6.00	\$ 6.00	\$ 6.00	\$ 6.00	\$ 6.00	\$ 6.00
Carbon Price- Pre-Compliance	\$ 8.50	\$ 8.50	\$ 8.50	\$ 8.50	\$ 8.50	\$ 8.50	\$ 8.50	\$ 8.50
Carbon Price- High	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00
Transaction costs								
PDD Development	\$ 25,000							
Verification	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000
Total	\$ 35,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000	\$ 10,000
Net Revenue								
Net Revenue- Voluntary	\$ (31,328)	\$ (6,328)	\$ (6,328)	\$ (6,328)	\$ (6,328)	\$ (6,328)	\$ (6,328)	\$ (6,328)
Net Revenue- TCT Purchase	\$ (27,655)	\$ (2,655)	\$ (2,655)	\$ (2,655)	\$ (2,655)	\$ (2,655)	\$ (2,655)	\$ (2,655)
Net Revenue- Pre-Compliance	\$ (24,595)	\$ 405	\$ 405	\$ 405	\$ 405	\$ 405	\$ 405	\$ 405
Net Revenue- High	\$ (16,639)	\$ 8,361	\$ 8,361	\$ 8,361	\$ 8,361	\$ 8,361	\$ 8,361	\$ 8,361

As can be seen from Figure 7.3, an assumed reduction in Global Warming Potential (GWP) of 50% due to nutrient recovery reductions in total N applied to the same land area (11 versus 5.5 pounds N/1,000 gallons lagoon water; 2,448 versus 1,224 MT CO_2e/year using MSU methodology) leads to quite limited potential revenue under a variety of price scenarios and, as such, these price structures were not included in the aforementioned Pro Forma.

Figure 7.4 is a purely theoretical example of how nutrient recovery might work, based upon partitioning of the nitrogen due to the use of nutrient recovery. In the figure, a hypothetical 1,000-cow dairy digester with somewhat typical nutrient concentration undergoes sequential and systematic treatment via fiber separation and then nutrient recovery as proposed by WSU. The resulting nutrient loads, fertilizer ratios, and required crop acreage is then compared to a scenario where no nutrient recovery is practiced.

Figure 7.4: Theoretical example of nutrient partitioning (S/L—solid liquid separation)



It can be seen that by partitioning the nutrients and using the nutrient pools in a targeted way for specialty crops then the overall nutrient load on the farm can be more effectively managed. In the no nutrient recovery scenario, nearly all of the nutrients (less those present in the fiber) are located in the lagoon water and as this lagoon water is in part viewed from a disposal standpoint, all might be applied at agronomic N rates to corn, thereby disposing of the nitrogen on 1,250 acres. By practicing nutrient recovery and partitioning much of the N in the concentrated bio-fertilizer, the lagoon wastewater are applied in an agronomic manner to 660 acres of alfalfa, while the concentrated bio-fertilizer can be sold to yield corn on another crop producer's acres (~700 acres). Importantly, this N leaves the impacted soil region and reduces the total N (as well as P and K) load to his fields by 70%, 83%, and 25%, respectively. Also of interest is that the partitioning process has potential for reducing ammonia losses during lagoon storage as well as reducing overall fuel costs during lagoon water application to fields.

CONCLUSION

DeRuyter is fortunate in developing, alongside its unique manure handling approach, a relatively simple, cost-efficient method for separating out a significant fraction of his phosphorus. It is possible though, that through a combination of substrate addition and/or more intensive regulation of ammonia, nitrate, and phosphorus emissions in the Basin, new approaches to combined nitrogen and phosphorus management could be warranted or required. These approaches could include active nutrient recovery systems aimed at partitioning the nutrients into relatively less concentrated lagoon water and highly concentrated, value-added bio-fertilizers, the latter, which could conceivably be exported out of the Basin, such as the fiber and present nutrients being produced in the baseline operation.

In this study, two new nutrient recovery approaches were assessed: a primarily phosphorus recovery approach in struvite crystallization and a combined nitrogen and phosphorus approach developed by WSU through modified ammonia stripping. Analysis of the struvite process shows an extremely negative cash flow due in part to additional chemical additions required by the peculiarities of digested dairy manure and its association with struvite precipitation. Analysis of the combined approach developed by WSU shows intensive capital and operating costs associated with the technology but potential for impressive revenues as well as exportation of nutrients from the produced bio-fertilizers. Under high, medium, and low revenue projections, only the high revenue scenario produced Pro Forma above that of baseline RNG, thereby positioning nutrient recovery as a latter stage insert only when regulation within the farm or Basin warrant its inclusion. Assuming inclusion due to regulatory concerns, incorporation of a working nutrient recovery system could conceivably lead to important reductions in nutrient loading as well as corresponding reductions in nitrate leaching, N_2O emissions and their effect on GWP, ammonia and PM 2.5, and eutrophication of waters. Estimates of nutrient partitioning in coordination with effective crop application yield reductions of 70%, 83%, and 25% NPK, respectively. Also of interest is that the partitioning process has potential for reducing ammonia losses during lagoon storage as well as reducing overall fuel costs during lagoon water application to fields.

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Chapter Eight — Project Permitting and Timeline

The purpose of this section is, in collaboration with the Governor's Office of Regulatory Assistance (ORA), to list the permits necessary to convert the DeRuyter CHP operation to RNG production and add nutrient recovery, identify important permitting timelines, and highlight potentially complex or problematic permitting issues. The intent is to provide a permitting framework for the DeRuyter project developer, and potentially other RNG / nutrient recovery projects, and to provide policymakers and agencies with a clearer sense of any regulatory impediments to the adoption of the model and support that could facilitate its application. ORA, which hosted an AD working group (including the dairy community and agency stakeholders), provided much of the following permitting information and guidance. The following permitting summary uses excerpts of several ORA products as well as interviews with regional air quality and Yakima County permitting experts.

Overview of Digester-Related Permitting Needs and Issues

The DeRuyter digester was permitted and constructed in 2006, and it is not anticipated that DeRuyter will build another digester, at least in the foreseeable future. The emphasis here is on the process of converting the current DeRuyter CHP operation to production of marketable RNG, nutrients, fiber, environmental credits, and potentially other products. However, because this feasibility study is also intended to inform others who might consider digestion of organic wastes, AD permitting will be summarized along with the RNG and nutrient recovery permitting requirements and issues. Permitting for dairy ADs primarily includes complying with state and regional environmental regulations and local building, zoning, and development codes. If a dairy AD receives federal funding it may also have to meet the federal requirements of the National Environmental Policy Act (NEPA). Each local jurisdiction has its own process for permitting new construction, in this case, the jurisdictions include Yakima County, Yakima Regional Clean Air Agency, and any other (e.g., City of Sunnyside) in which project facilities may be constructed.

Current state and regional environmental permitting requirements for dairy ADs

The primary state and regional environmental regulations affecting the construction and operation of dairy ADs are in the areas of solid waste, air quality, water quality and dairy nutrient management. Collaboration between agencies and stakeholders has significantly simplified the environmental permitting process for the existing dairy ADs (Figure 8.1).

Solid Waste

Initially, dairy ADs in Washington were conceived as "manure only" ADs, meaning they did not plan to use any additional organic substrates, such as food processing waste. This business model quickly changed, however, when the economics of dairy AD operations became clearer. The digestion of manure alone does not create nearly as much biogas as manure combined with additional organic material. The additional biogas means that more electricity or RNG can be produced, generating additional revenue. If this extra income is combined with tipping fees received for accepting the waste, the economic boost to the dairy AD operations can be significant. All dairy ADs currently operating in waste-rich western Washington add pre-consumer organic waste and consider it essential to economic success. The substrate market in central and eastern Washington is significantly different: less urban and industrial organic waste is generated, and there are more low-cost opportunities to off-load waste products. As a result, the DeRuyter AD operates almost entirely on dairy manure, although that could change with incentives to maximize gas production using high-energy substrates that also do not adversely affect the DeRuyters' fiber or nutrient management objectives.

What does the addition of other organic material to dairy ADs mean for environmental permitting? It normally would trigger state solid waste regulations; the AD accepting organic wastes along with manure would be required to obtain a Solid Waste Handling Permit (SWHP). Under this situation, the liquid and solid effluents from the digester, at least from a regulatory perspective, would then no longer be considered manure but solid waste and would require permitting/handling as such. Without the addition of other substrates, the dairy AD operation would not need a SWHP, and the effluents would be considered manure. Dairy AD operators were concerned about needing a SWHP and raised the issue with state legislators. In response, in 2009, a law was passed providing an exemption from the SWHP for dairy digesters that accept off-farm organic waste and meet certain conditions (RCW 70.95.330). State agencies, including the departments of Agriculture, Health, and Ecology, worked together with stakeholders to develop guidelines for the exemption, which were published in 2009. As a result of the co-digestion exemption:

- No solid waste permit is required for dairy ADs meeting the conditions of RCW 70.95.330.
- Dairy ADs must submit a *Notice of Intent to Operate* and annual reports to the Department of Ecology (or the local jurisdictional health department) and allow regular inspections.

Air Quality

Because dairy ADs burn biogas in their engines or boilers, they are new or modified sources of air pollution. As such, the owner of an AD must contact either the Department of Ecology or the appropriate regional air quality authority to go through the new source review process and to determine if an air permit will be required. Air permits regulate pollutants such as particulates, ammonia, nitrogen dioxide, and sulfur dioxide. All AD projects currently operating in Washington have required a Notice of Construction/Order of Approval permit. To simplify the air permitting process for dairy ADs that are exempt from solid waste permitting, the Department of Ecology's Air Quality Program, the Northwest Clean Air Agency, the Puget Sound Clean Air Agency, and the Yakima Regional Clean Air Agency worked with stakeholders to develop a new General Order of Approval (GO) specifically for dairy ADs meeting the solid waste exemption. It applies to CHP operations but not to RNG operations because there is not yet any operational experience with RNG production at dairy ADs. A GO is essentially a pre-written permit that includes clearly defined emission criteria, best available control technology, and other requirements. ADs that meet the applicability criteria have a significantly streamlined air permitting process and lower permit fees. Ecology issued GO No. 12 AQ-GO-01 in April 2012.

It is assumed that RNG production would require a *Notice of Construction/Order of Approval* (NOC) permit, although if there is no significant adverse change in emissions, the applicant could seek an *Applicability Determination* ("*b (10) exemption*"), which could exempt the project from the NOC program. Air quality permitting therefore would be conducted either through:

- The *General Order of Approval* (GO for CHP only);
- Notice of Construction/Order of Approval (NOC for CHP or RNG), or;
- NOC Applicability Determination establishing emissions are "*de minimis*" and therefore exempt from NOC program.

The combined nutrient recovery system being proposed as a potential nutrient recovery system for consideration in the DeRuyter project does strip gases, ammonia and carbon dioxide, from the manure and passes these gases through an acid contact tower. Nearly 99% of the stripped ammonia is absorbed through the acid contact process with the remaining carbon dioxide and water vapor exited from the tower. Although not a regulated gas, quantification of the carbon dioxide release is needed for reporting purposes.

<u>Water Quality</u>
State Waste Discharge Permits (SWDP) are generally required for discharges to surface or ground water in Washington State. If a dairy chooses to operate without a SWDP, the operator is responsible for ensuring that no discharges occur. A properly designed manure storage lagoon is considered non-discharging and can be constructed without a SWDP. When manure from the lagoon is land applied, state law requires that it be applied at agronomic rates and that there is minimal leaching below the root zone. State law also requires that a plan be developed which describes how the material will be applied to prevent surface and groundwater pollution. These plans are commonly referred to as "nutrient management plans." The state's Dairy Nutrient Management Act (Chapter 90.64 RCW) requires all commercial dairy farms to develop and implement nutrient management plans to protect surface and ground water quality. A SWDP is generally not issued. The Dairy Nutrient Management Plan (DNMP) outlines how much and when solid and liquid nutrients can be applied to fields. If a plan is updated as conditions change

(such as the addition of a digester or off-farm substrates) and followed properly, it can be an effective tool to prevent discharges to ground or surface water.

The DNMP is developed by the dairy and approved by the local Conservation District. Inspections are conducted by the Washington State Department of Agriculture. Thus, in terms of water quality permitting:

- No water quality permit is required if there are no discharges to ground or surface water.
- Dairies must develop a Dairy Nutrient Management Plan, register with the Washington State Department of Agriculture, and allow regular inspections.

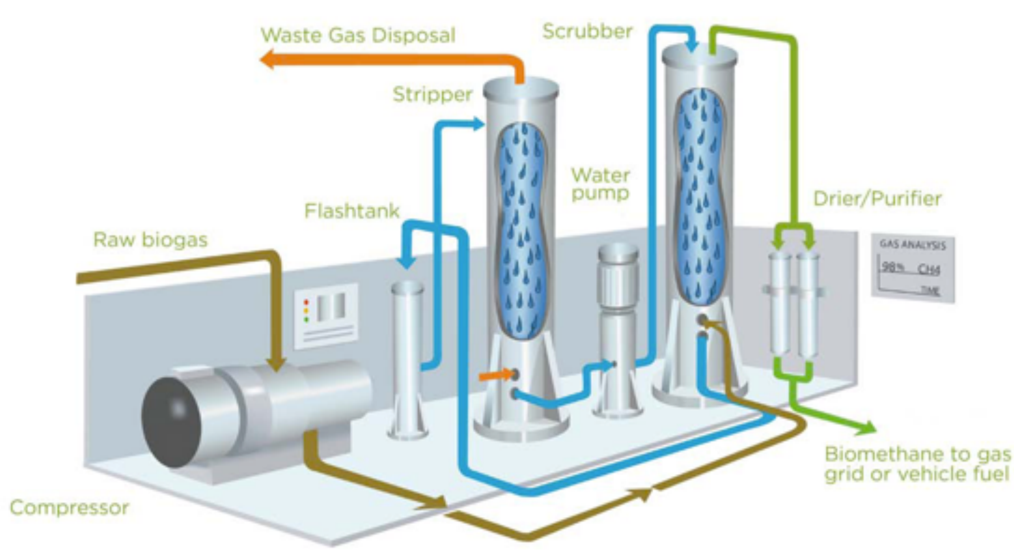
The State Environmental Policy Act (SEPA) and National Environmental Policy Act (NEPA) would apply to the overall project environmental review if the project creates significant adverse environmental effects, and, in the case of NEPA, if there is a federal nexus, such as a federal permit or funding. SEPA and NEPA consider overall project impacts and are conducted or overseen by a lead agency (typically the agency with initial or primary permit decisions). These environmental reviews can include:

- SEPA Checklist: County, YRCAA, or Ecology (based on first permit decision)
- NEPA Environmental Assessment or EIS: federal agency with jurisdiction (if nexus)

Summary of RNG and Nutrient Recovery Project Elements

Gas Cleaning Unit and Compressor
A Flotech Greenlane gas-cleaning unit (Rimu) is an example of the type of equipment that would be used to convert raw biogas from the existing AD to pipeline quality RNG (Figure 8.1).

Figure 8.1: Flotech Greenlane Rimu



Emissions from the unit are primarily CO_2, some of which could be used in greenhouses or industrial processes, and significantly less NO_2 and SO_2 than the emissions from the current engine sets. No significant releases of hydrogen sulfide are expected. The gas cleaning unit (GCU) fits on a 40' skid and has two towers approximately 45' high. The unit, and compressor, could utilize the footprint of the existing powerhouse or an area adjacent to it.

Permitting for the GCU and compressor could include:

- Air Quality Notice of Construction, Applicability Determination: Yakima Regional Clean Air Agency
- Local construction permit: Yakima County Public Services
- Electrical permit: Washington State Department of Labor & Industries

RNG transport to Williams pipeline or fueling station

There are two options for transporting the RNG from the DeRuyter dairy to the Williams pipeline (Wenatchee Lateral) or a fueling station:

- A three-inch pipeline from the dairy 3.7 miles down Dekker Road to a meter station and injection into the Williams pipeline using the existing Dekker Road utility right of way.
- Shuttling compressed RNG in tube trailers from DeRuyter to a meter station and injection point or to a fueling station (e.g., Port of Sunnyside property next to Darigold).

Permitting for transportation of RNG from the DeRuyter dairy could include:

- Pipeline:
    - Franchise Agreement for use of utility corridor on Dekker Road (Yakima County Public Services) and construction permit
    - Construction Storm water Permit: (Ecology -- > 3 miles of trenching)
- Tube trailers: certification by DOT; connections and valves must meet fire and safety codes (see National Fire Protection Association Code, Title 52: standards for CNG vehicular systems).

Meter station and injection point

A meter station, with a fenced 100' x 100' footprint, would be built (or an existing station adapted) at or near a selected interconnection point with the Williams pipeline. The meter station and injection point ("interconnect") would include gas monitoring and management equipment in a shed (approx. 10' x 15'). If tube trailers are used as the RNG delivery method, space would be needed for tube trailer unloading and turnaround. Potential locations for a meter station include: 1) Dekker Road, near intersection with Williams pipeline; 2) Port of Sunnyside fueling station (where RNG could be injected and/or stored and CNG withdrawn); or 3) existing meter station at 9390 Emerald Road (Figure 8.2). Permitting for meter station and injection point, which would be accomplished by or in close coordination with Williams Gas Pipeline, could include:

- Local construction permit: Yakima County Public Services
- Electrical permit: Washington State Department of Labor & Industries
- Franchise Agreement: Yakima County Public Services (not needed if gas utility builds and operates the pipeline)

Figure 8.2: Example meter station in Sunnyside (9390 Emerald Road)

Fueling station

A CNG fueling station, likely located on industrial property owned by the Port of Sunnyside (see aerial photo below with proposed fueling station site in red cross hatching and Emerald Road meter station partially visible on west side(Figure 8.3)), would include:

- Connection to the Williams pipeline (which runs under the property);
- Compressor;
- An array of high pressure storage tubes; and
- Dispensers (gas pumps).

If RNG is delivered directly to the station, space would be needed for tube trailer unloading and a connection to the compressor and storage tubes. Permitting for an RNG/CNG fueling station, which would be accomplished by or in close coordination with the Port of Sunnyside, could include:

- Local construction permit: Yakima County Public Services
- Electrical permit: Washington State Department of Labor & Industries
- Compliance with Gas Code: NFPA Code, Title 52: Standards for CNG Vehicular Systems

Figure 8.3: Map of potential fueling station, Port of Sunnyside industrial property

Focus on Potentially Complex, Problematic Permit Issues

Although it does not appear that any of the likely permitting requirements for the CHP to RNG project are potential "show stoppers," air quality permitting for the conversion from CHP to RNG – namely, the gas cleaning unit -- has some complexity and uncertainty that warrants special attention here. When DeRuyter applied to the Yakima Regional Clean Air Agency (YRCAA) for its CHP air quality permit six years ago, it went through the *New Source Review* process and was issued a *Notice of Construction/Order of Approval permit*. Today, a new dairy-based AD in the area with a CHP operation could be permitted under the streamlined General Order that was recently promulgated by Ecology. Although the conversion of a CHP operation to RNG should result in significantly reduced emission of criteria pollutants, its new status means that the GO shortcut is not available. Although RNG production could result in lower emissions of most pollutants, the appearance of a new pollutant, such as hydrogen sulfide (H_2S), could trigger the new source review. It all depends on whether YRCAA is provided with sufficient information to conclude that there would be no significant increase in a key pollutant, such as H_2S that would have been combusted to form SO_2 under the CHP design but could emerge as a new pollutant under the RNG operation unless it is effectively controlled (e.g., through filtration, adding controlled amounts of air to the digester, and/or flaring).

RNG project design and control equipment can address such air quality issues and must be presented to YRCAA to avoid difficult and protracted air quality permitting. There are two ways to secure a timely air quality permit:

- Notice of Construction review process: If the application is complete and there are no significant questions, the process can take 30-60 days; the application fee is $400 plus hourly fees for agency review (total cost $2000 -$3000), or;
- NOC Applicability Determination ("b (10) exemption"): If information is provided sufficient to support the conclusion that the emissions are "*de minimis*" and that the technology proposed is consistent with that conclusion; timeframe is typically 30-45 days from submission of a complete application ($1000 filing fee).

The information requirements for the two options are virtually the same:

- Description of the project process;
- All emission information;
- An evaluation of the emission control technologies available for the proposed equipment, and;
- Information to the agency sufficient to determine that the proposal:
    - Operates within existing emission limits;
    - Will employ best available control technology (BACT), and;
    - Will not create an adverse air quality impact offsite.

Safety Issues

Both the RNG and nutrient recovery systems operate equipment under pressure and/or utilize corrosive chemicals (i.e. acids, fertilizers). OSHA regulations will need to be met in regard to storage, operation (loading, storage, metering) of the chemicals, as well as training of the laborers in regard to safety involved with chemicals and pressure equipment. In addition, the nutrient recovery system will be producing fertilizer products, which will need to be stored and marketed according to WSDA regulations.

PROJECT PERMITTING AND TIMELINE CONCLUSIONS

As long as the DeRuyter project developer provides sufficient information in a timely and professional manner, project permitting should be fairly straightforward. The permits sought have reasonable timelines and costs in light of the size of the project, there does not appear to be any significant opposition to the project or threat of litigation or appeal, and the regulatory agencies with jurisdiction have been collaborating with AD stakeholders and agencies to facilitate AD projects (Table 8.1 and Figure 8.5).

The most complex and uncertain permitting path is air quality. Although conversion from CHP to RNG does not qualify for the recent General Order for AD air permitting, there are two viable pathways (Notice of Construction air permit review and NOC Applicability Determination) so long as the necessary information is made available to the Yakima Regional Clean Air Agency.

The project timeline estimates that it will take approximately one year to complete the RNG portion of the project (Figure 8.6). This timeline is based on private sector funding; if public funding is used, the timeline would probably be extended by at least six months. Overall, it is expected that there would be five discreet phases or steps in the full transformation of the DeRuyter digester from the existing CHP operation to RNG with advanced nutrient recovery:

1. **Baseline CHP operation plus fiber and phosphorous solids**: Although power revenues alone would not justify CHP operation, heat from the generator sets is needed to operate the digester which, in addition to biogas-to-electricity, makes possible revenue from a valuable peat moss substitute and phosphorous bio-fertilizer.
2. **Substrate evaluation:** Before committing to full conversion to RNG, it is important to determine whether high-energy substrates can be secured that boost biogas production (from 300 to 500 cfm biogas) while maintaining a high-quality fiber product – DeRuyter's most significant revenue generator. Additionally, the impact of additional substrates on the nutrient management program must also be analyzed. Because of the high cost of operating the gen sets, renewable options for digester thermal needs should be evaluated, including a biogas boiler, solar (thermal and photovoltaic), wind, and geothermal.
3. **RNG Conversion Funding and Agreements**. Private and/or public funding partnerships should be explored and secured to reduce the risk for the RNG conversion. Most critically, firm long-term sales agreements should be arranged before committing to RNG.
4. **RNG conversion:** The highest value for RNG is taking it as vehicle fuel at a retail fueling station, plus RINs and other incentive payments. Combined with revenue from fiber, bio-fertilizer, and carbon credits, the RNG model promises to be a profitable use of AD biogas and an important part of a DeRuyter AD-based waste-to-revenue system. This option generates greater pre-tax cash flow even without RIN values. Even within the

RNG conversion stage, there are at least two steps. The first step is a simple, DeRuyter-only demonstration of RNG; the second step would include all the infrastructure needed to transport, store and distribute RNG at a centralized facility, such as the Port of Sunnyside.

5. **Addition of advanced nutrient recovery:** With coming advances in commercially viable nutrient recovery technology, it would make sense to evaluate and time this final step to the DeRuyter system to coincide with these advances. It should be noted that public support for this AD model will probably be predicted upon demonstration of a strong nutrient management / recovery system.

Combining these stages or steps, even with some overlap, is likely to take two years or more to be fully implemented. However, within each step, important components, strategies, markets, and systems can be tested and demonstrated. Figure 8.4 summarizes this staged approach and its decision making steps.

Figure 8.4: Staged approach

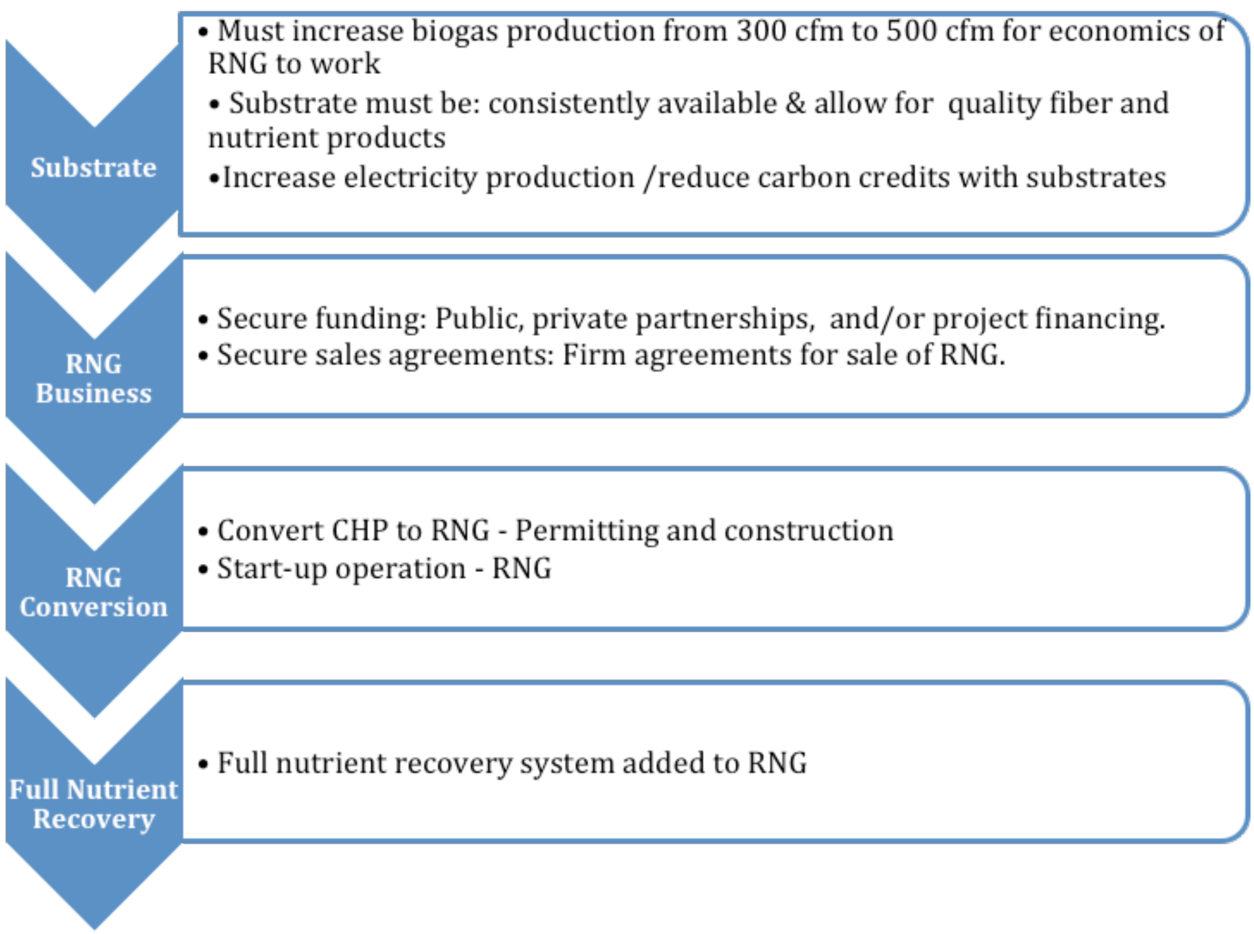


Table 8.1: Permitting Process Table

WASHINGTON STATE Governor's Office of Regulatory Assistance

Promus Energy – DeRuyter Dairy Digester

- Table below is for reference purposes only. Applicants are advised to consult with local, state, and federal authorities since permit requirements vary based on site-specific conditions.
- The term "permit" in the table below is a synonym for process, permit, authorization, license, requirement, certificate, and approval.
- Federal funding may trigger additional review under the National Environmental Policy Act (NEPA) and Section 106 National Historic Preservation Act.
- More complete information regarding permits may be found at www.ora.wa.gov.

Local Permits			
Permit	**Lead Agency**	**Contact**	**Comments**
Notice of New Construction	Yakima Regional Clean Air Agency (YRCAA)	Hasan Tahat, Ph.D. Engineering and Planning Division Supervisor Yakima Regional Clean Air Agency Tel: (509) 834-2050 ext. 105 Fax: (509) 834-2060 E-mail: hasan@yrcaa.org	• Review Time: If application complete and no questions, 30-60 days. • Permit Cost: $400 application fee plus hourly fee for agency review
Franchise Agreement	Yakima County Public Services Department	Alan Adolf (509) 574-2300 Alan.adolf@co.yakima.wa.us	• Not needed if Williams or Cascade build and operate pipeline • If new franchise, public notice, possible hearing; 45-60 days • $150 franchise fee

Local Permits			
Permit	**Lead Agency**	**Contact**	**Comments**
State Environmental Policy Act (SEPA)			• Yakima County if County is permitting. Otherwise, YRCAA or Ecology, whichever is first in line for a permit decision.
Nutrient Management Plan	South Yakima Conservation District	Laurie Crowe (509) 829-9025 lc@sycd.us	• Update nutrient management plan to reflect addition of other feedstock

State Permits			
Permit	**Lead Agency**	**Contact**	**Comments**
Electrical Permit	Labor & Industries	L & Industries 15 West Yakima, #100 Yakima, WA 98902 (509) 454-3700	• Permit for electrical work.
Construction Storm water Permit	Ecology	Bryan Neet	• If 3 miles of trenching, this permit is triggered

Federal Permits			
Permit	**Lead Agency**	**Contact**	**Comments**
NEPA	Funding agency or permitting agency		If federal funding or other federal nexus.

Figure 8.5: Summary of the permitting requirements

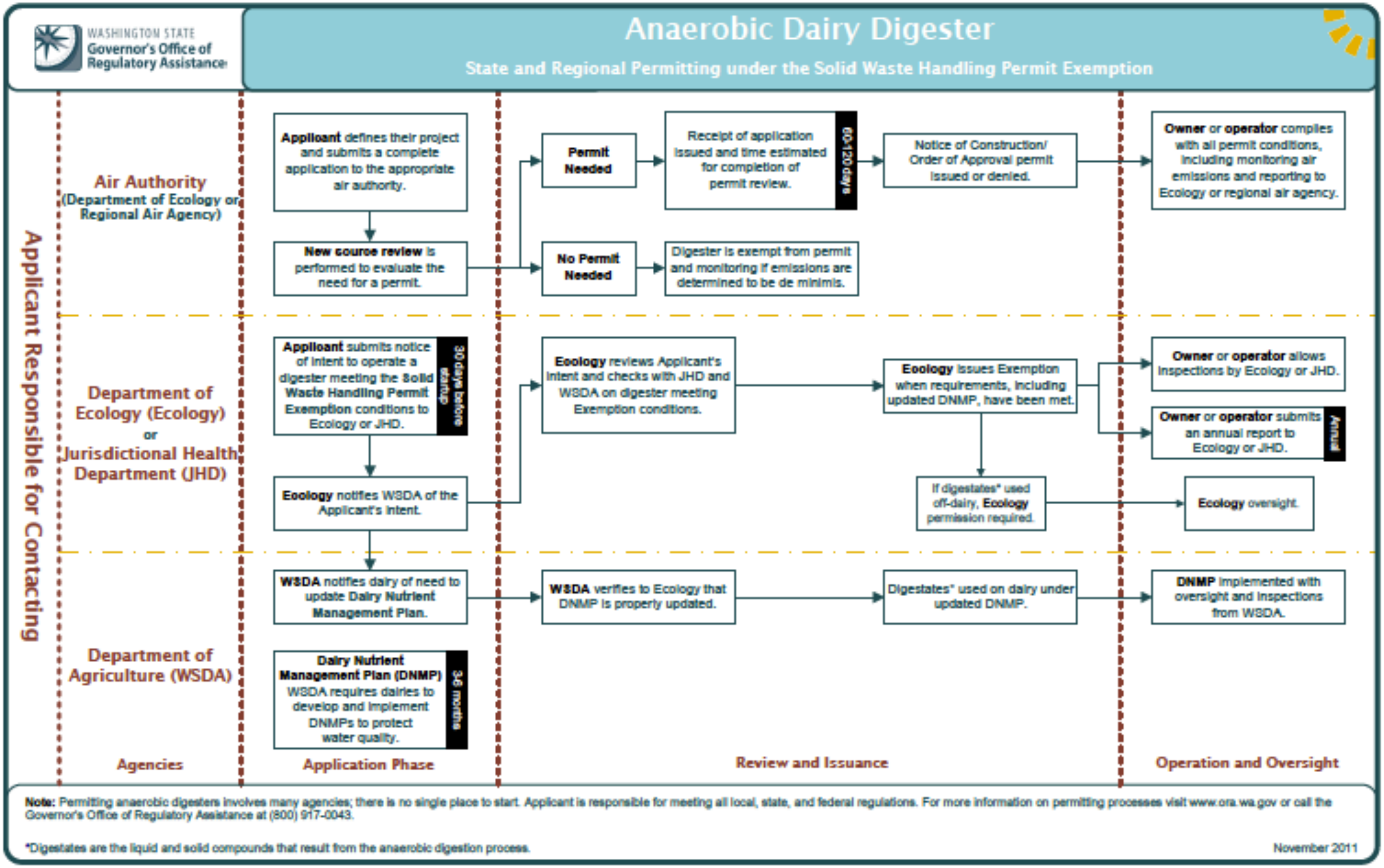
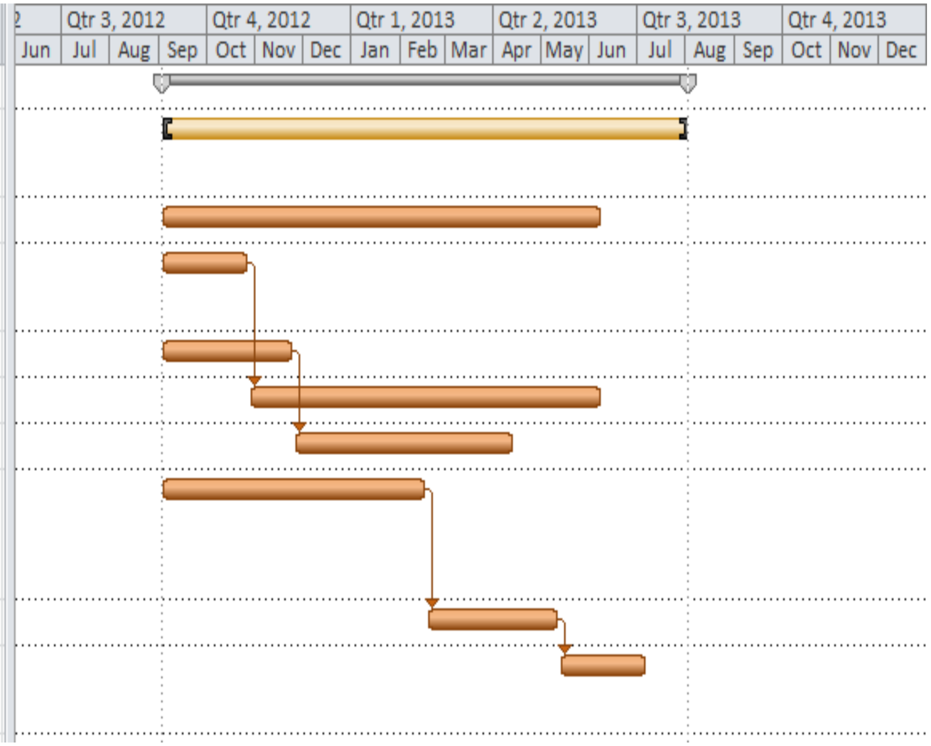


Figure 8.6: Tentative timeline for project staging

Task Name	Duration	Start	Finish	Predecessors
DeRuyterSched1	**240 days**	**Mon 9/3/12**	**Fri 8/2/13**	
Research additional substrates	12 mons	Mon 9/3/12	Fri 8/2/13	
Substrate Agreements	10 mons	Mon 9/3/12	Fri 6/7/13	
Pre-design Consultations	2 mons	Mon 9/3/12	Fri 10/26/12	
Design/Engineering	3 mons	Mon 9/3/12	Fri 11/23/12	
Equipment Procurement	8 mons	Mon 10/29/12	Fri 6/7/13	3
Permitting	5 mons	Mon 11/26/12	Fri 4/12/13	4
Private Financing **public financing up to 12 months	6 mons	Mon 9/3/12	Fri 2/15/13	
Construction	3 mons	Mon 2/18/13	Fri 5/10/13	7
Pre-operational Tests/Refinements	2 mons	Mon 5/13/13	Fri 7/5/13	8



Chapter Nine — Conclusions

After compilation of the data and analysis of the project outputs, the project team can highlight key conclusions as well as make future project planning suggestions. Each of the main conclusions is summarized in order of display within the report, starting with the baseline CHP and continuing through to a staged implementation plan for RNG production. Discussion of conclusions within each section is accompanied by policy suggestions that could accelerate development of AD-based waste-to-revenue systems not only within the DeRuyter project but the Columbia Basin as a whole.

Baseline CHP

The first important conclusion drawn from the economic analysis of the baseline CHP project is that the DeRuyter AD project has a pre-tax, positive cash balance — one that continues and slightly grows with time, despite reductions in received electrical prices. The positive cash flow, ranging from approximately $0.5-1 million across the 20-year projection, experiences both decreasing slopes (2013 — lowered electrical prices; 2023 — loss of carbon credits) and increasing slopes (2014—increased carbon credit pricing and full realization of nutrients sales; 2027—end of debt service). This cash flow is thanks in great part to the value-added products coming off the back end of the digestion process — the fiber for RePeet production and the phosphorus-rich fine solids. Presently these two products combine to represent 46% of the project revenue, but in 2013, with the reduced electrical sales prices, they total 61%, and ultimately, near the end of the Pro Forma, they near 70% of total revenue. Accolades should be given to the DeRuyter dairy as well as partnering industries associated with the fiber and nutrient markets, as it is only through development of these value-added products that the project is able to stay cash positive. It should be noted that there are new and evolving markets.

From a regional perspective, continued development and growth of these two product markets could conceivably allow for deployment of a new farm-based AD model that compensates for particularly low electrical prices n the Columbia Basin. Application of this model, though, will still be strongly influenced by even small to moderate elevations in received electrical prices, capital debt structures for the AD projects, and maturity and growth potential for the co-product markets.

<u>Policy Suggestions</u> - *To replicate the developing DeRuyter co-product model with other dairies, and within the Columbia Basin, it is suggested that: 1) state agencies continue to identify ways project developers can gain access to grants and low-interest loan; 2) Washington Utilities and Transportation Commission (UTC) responses to 'avoided cost' regulations (WAC 480-107-095) be supportive of digester development; and 3) Basin-wide incentives be explored for exporting nutrients out of overloaded areas via sales of co-products such as fiber and phosphorus-rich*

solids. In addition, as carbon credits and RECs represent small but important sources of revenue, the Energy Independence Act (RCW 19.285.030) should be amended so as to decouple RECs and carbon credits resulting from methane capture.

Non-RNG Modifications to the Baseline CHP

The analyses showed that present and future cash flow of the CHP model could be improved by the addition of substrate that produces additional biogas and additional generator capacity (new or used). While not a marked improvement, especially in the first years, enhanced biogas production from substrates combined with an additional used engine/generator set leads to roughly 30% increase in cash flow as compared to the existing non-substrate baseline. This potential cash benefit could be offset by concerns of the increased loading of nutrients that might occur due to substrate intake and digestion. Importantly, investment in such a plan (debt structure on the additional engine prices at approximately $1.1 million) only makes sense if at first it becomes clear that 20-30% substrate addition is achievable on a consistent and reliable basis while not adversely affecting the nutrient management plan for the farm and the region. Of equal importance, is that the type and volume of substrates added not adversely affect the valuable downstream processes for production of fiber and nutrient-rich solids.

<u>Policy Suggestions</u> – *How to appropriately manage and mitigate the increased nutrient loading that would come from the addition of substrate needs to be discussed among the agricultural community, nutrient management planners, regional and federal agencies and industry. It is suggested that every effort be made to bring interested parties to the table to further discuss nutrient management planning and implementation, concerns, responses and alternatives for redistribution. This is so that if substrate addition is practiced here and elsewhere in the Basin, there is a firm understanding of plans, the known environmental fates, and the regional impacts especially in relation to the other co-product sales efforts that distribute locally and also export nutrients out of the Basin. Assuming a valued and agreed response is achievable, implementation of such AD business models could only be strengthened through targeted connections between dairy AD operators and organic waste producers in the region, with facilitation and assistance by solid waste agencies welcomed.*

RNG Markets and Off-Takes

Development of the RNG model at DeRuyter and across the Basin requires the installation of RNG infrastructure and long-term off-take agreements and credits that generate attractive net cash flow scenarios. Identified challenges to the RNG model resides strongly on the high capital cost of RNG infrastructure, particularly facilities and equipment related to RNG distribution (pipelines and/or tube trailers), pipeline injection point/meter stations, and RNG/CNG fueling stations that set the stage for widespread RNG production and use. While DeRuyter and/or third-party equity partners can conceivably handle the debt load associated with installation of biogas purification and compression equipment on the farm under most scenarios, it is the additional, intensive capital costs associated with the off-farm, 'to the market' infrastructure that becomes particularly problematic to project development if the associated cost and risk is borne by a single RNG producer. Additional risk and uncertainty resides in environmental credits associated with RNG production and use – namely, RINs, which currently can add the equivalent of $1.10 per GGE. However, the primary need in establishing the viability of the RNG model is the securing of high-value, long-term agreements with end users; and the primary impediment to the RNG model resides in the 'to the market' associated capital costs.

Policy Suggestions – Public-private partnerships, involving ports, economic development organizations, and other general and special purpose local governments, should be formed to tap public financing mechanisms that could provide infrastructure necessary for capital expenditure structures and business plans. Federal, state and local government fleets, as well as regional greenhouse gas mitigation (Hanford) and energy programs (power back-up), could be instrumental as first-stage end-user markets. Market-setting policies, such as bid preferences for renewable fuels in government contracts for transportation services (e.g., waste hauling), should be encouraged. In addition, federal policies that add certainty and long-term value to the RIN market would reduce RNG investor risk.

RNG Model

The RNG model offers strong opportunities, especially if the above capital expenditure issues could be mitigated by private/public partnership. Two important RNG supporting factors delineated by the team include:

- Use of RNG within an AD-based "integrated systems approach" producing multiple revenues such as renewable fuel, nutrients, fiber products (compost and peat moss substitute), CO_2, and other "by-products;"and
- The rise in the cost of petroleum, the growing availability of CNG and natural gas vehicles and conversions for popular heavy-duty truck engines, and the resulting national shift to methane fuels in the high-value transportation fuels market.

RNG was evaluated under three pricing scenarios (commodity, commodity plus RIN, and Retail Fast Fuel Sales) and compared to the current and 2 MW substrate CHP models:

1. Commodity natural gas pricing: Even if sold at low wholesale prices for pipeline gas ($3.87/MMBTU or $0.44/GGE), RNG approximates but is slightly below (~$200-300K) the CHP model in cash flow.
2. Commodity plus "green premium" (RIN): When renewable credits are added to the commodity price of gas, this RNG model generates more cash flow than CHP ($140-450K for low RIN and $1.2-1.9M for current RIN). Gas utilities, brokers, and CNG retailers are potential purchasers at this pricing if DeRuyter negotiates a split of the RIN value with the purchaser.

3. Retail CNG plus RIN: If producers take RNG to the retail CNG market, where CNG is now selling for $1.85 and up, it generates much more revenue than CHP, especially if credits are added ($1.2-2M for low RIN and $2.2-3.5M for current RIN). Even if credits are not added, this scenario still generates more cash flow than the current CHP model.

Policy Suggestions – *While extensive private opportunity exists, governments could help demonstrate and accelerate adoption of AD-based RNG systems by implementing policies that:*

- *Reduce the risk of RNG infrastructure through grants and non-recourse loans.*
- *Facilitate cost sharing of common infrastructure through cooperatives, public "hosts," or similar public-private partnerships.*
- *Provide regulatory flexibility and clarity that supports diverse AD-related revenue streams, including an integrated systems approach, based on site-specific factors, that allows for revenue from energy, nutrients, fiber, carbon dioxide, environmental and carbon credits, and other waste-to-revenue products.*
- *Support the RNG market through government purchases of RNG and contract provisions that incentivize RNG use by government contractors.*

Nutrient Recovery

DeRuyter is fortunate in developing, alongside its unique manure handling approach, a relatively simple, cost-efficient method for separating out a significant fraction of its phosphorus. It is possible though that through a combination of substrate addition and/or more intensive regulation of ammonia, nitrate, and phosphorus emissions in the Basin, new approaches to combined nitrogen, and phosphorus management could be warranted or required. These approaches could include active nutrient recovery systems aimed at partitioning the nutrients into relatively less concentrated lagoon water and highly concentrated, value-added bio-fertilizers, the latter, which could conceivably be exported out of the Basin such as the fiber and nutrients being produced in the baseline operation.

In this study, two new nutrient recovery approaches were assessed, a primarily phosphorus recovery approach in struvite crystallization and a combined nitrogen and phosphorus approach developed by WSU through modified ammonia stripping. Analysis of the struvite process shows a strongly negative cash flow due in part to additional chemical additions required by the peculiarities of digested dairy manure and its association with struvite precipitation. Analysis of the combined approach developed by WSU shows intensive capital and operating costs associated with the technology, but potential for impressive revenues as well as exportation of nutrients from the produced bio-fertilizers. Under high, medium, and low revenue projections, only the high revenue scenario produced Pro Forma above that of baseline RNG, thereby positioning nutrient recovery as a latter stage insert only when regulation within the farm or Basin warrant its inclusion. Assuming inclusion due to regulatory concerns, incorporation of a working nutrient recovery system could conceivably lead to important reductions in nutrient loading as well as corresponding reductions in nitrate leaching, N_2O emissions and their effect on GWP, ammonia and PM 2.5, and eutrophication of waters. Estimates of nutrient partitioning in coordination with effective crop application yield reductions of 70%, 83%, and 25%, nitrogen, phosphorus, and potassium, respectively. Also of interest is that the partitioning process has potential for reducing ammonia losses during lagoon storage as well as reducing overall fuel costs during lagoon water application to fields.

Policy Suggestions – Nutrient recovery, while costly and still in its infancy, holds strong potential for reducing nutrient threats to surface and ground waters, especially within CAFO areas. It is suggested that the State crafts policies and incentives that can further technology and market development associated with bio-fertilizers. Projects that can produce renewable energy and bio-fertilizers while simultaneously supporting CAFO economic viability and improved environmental sustainability are truly win-win opportunities for the state and region.

Staged Approach

Several potential sequential/overlapping stages beyond the current CHP operation can be proposed for the DeRuyter project, and for putting AD-based waste-to-revenue systems into broader play:

1. **Substrate & enhanced CHP:** Secure high-energy substrate to boost biogas production that does not adversely affect fiber product or nutrient recovery, and which, in combination with additional generator capacity, boosts electricity revenue.
2. **RNG business structure:** Secure developer/partner, financing/grants and "hosts" for common off-farm RNG infrastructure (distribution, pipeline injection, fueling), and long-term off-taker agreements.
3. **RNG conversion:** Based on stages 1 and 2, convert the DeRuyter CHP operation to RNG production through an AD system that maximizes revenue from organic wastes.
4. **Full nutrient recovery:** As dictated by farm and regional nutrient mass balance, regulatory requirements, commercially available technology, and nutrient markets, implement full nutrient recovery as part of AD-based waste-to-revenue systems.

Policy Suggestions – A staged approach with a clear timeline appears to be most viable with regard to risk management and capital resource utilization. It is important that the state work side-by-side with DeRuyter as this staged implementation approach is developed – providing appropriate assistance in securing substrate, infrastructure and off-take agreements while working with the farm on long-term nutrient management issues.

Scale Issues and Application of Model to other Farms within the Basin

An important question raised by this feasibility study is the optimal (or viable) scale for the development of manure-based AD systems. At the decentralized end of the continuum is the 'stand alone' operation, such as DeRuyter. As noted in the analyses and summary, the capital cost of off-farm RNG infrastructure creates challenges for the single dairy operator and effectively requires that the dairy have at least several thousand cows and/or high energy substrate, as well as high-value long-term off-take agreements, to make it viable. At the other end of the continuum is the centralized 'community digester' and gas cleaning operation concept, which requires piping and/or trucking manure and substrate from miles away and then hauling nutrients and waste products back out to regional farms and perhaps out of the Basin.

An option recommended by the study team for additional evaluation, at least in locations such as the Sunnyside/Outlook area where tens of thousands of dairy cows and feedlots are concentrated, is a medium-scale, semi-centralized AD system. Under this semi-centralized approach, dairies within 1 to 2 miles (subject to sensitivity analysis) from one another could be connected in one of two ways: (1) by manure slurry piping that would pool manure and substrate in a central digester and gas cleaning operation; or (2) by low pressure gas from decentralized digesters to a central gas cleaning and compression operation. The gas cleaning operation should be located as close as feasible to a natural gas transmission line, where the RNG would be injected into the gas grid at a meter station hosted by the gas or pipeline utility.

An example of an attractive scenario would be based on manure from 10,000 cows within a mile radius, supplemented with substrate that would boost biogas production to 1000-1200 cfm without adversely affecting fiber products or nutrient management. Such a facility could produce more than 9,000 RNG GGEs/day, take advantage of economies of scale for gas cleaning and off-farm RNG infrastructure, and move manure or biogas to a central operation via efficient pipelines. Notably, development of such a 'hub' approach could be replicated to other 10,000-cow-scale hubs, producing multiple hubs that encompass the entire Basin. Such a approach involving 10,000-cow hubs could alleviate the key concerns present within the other business approaches at either end of the scale (low biogas production volume, hauling of manure on roads, etc.) while also allowing for economies of scale (shared nutrient and co-product markets, RNG fueling stations/markets, etc.) and more effective funding/construction timelines.

The conundrum is that neighboring dairies may be unwilling to participate in the organization of a semi-centralized digester until the RNG and AD-based waste-to-revenue model is demonstrated and shown to be technically feasible and financially attractive. At the same time, DeRuyter faces challenges with a 'stand alone' model unless he can get support for off-farm RNG infrastructure. Recommended solutions to this conundrum include: (1) private investment to provide the capital and assume the risk of the project; (2) public investment (low-interest/non-recourse loans and grants); (3) 'hosting' of key infrastructure by gas/pipeline utilities or economic development entities (e.g., Port of Sunnyside); (4) the creation of an AD cooperative; or (5) some combination of the above.

The potential rewards and risks associated with the AD-based waste-to-revenue system are great. The underlying drivers – promisingly profitable conversion of wastes and nutrients to revenue, regulatory assurances, a fuel that is half the cost of diesel, and sustainable marketing benefits – are strong. So are key uncertainties – RNG valuation and long-term off-take agreements, environmental credits, support for off-farm infrastructure – and the high capital cost of the model. The national shift to methane fuels will address some of the impediments (fueling, natural gas vehicle availability), as will the maturation of environmental credit markets (RECs, RINs, carbon credits). The logical next step would be for private and/or public entities to pull together the elements evaluated in this feasibility study into a business plan and financing package, which will likely require the coordination of several partners.

Chapter Ten — Appendixes