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THE ECONOMICS OF ANAEROBIC DIGESTION UNDER
DIFFERENT ELECTRICITY PURCHASE AGREEMENTS

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David F. Binkley

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MASTER OF SCIENCE degree in Agricultural Economics

Stephen B. Harsh
Major Professor's Signature

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THE ECONOMICS OF ANAEROBIC DIGESTION UNDER DIFFERENT ELECTRICITY PURCHASE AGREEMENTS

By

David F. Binkley

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Submitted to
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ABSTRACT

THE ECONOMICS OF ANAEROBIC DIGESTION UNDER DIFFERENT UTILITY PURCHASE AGREEMENTS

By

David Binkley

Anaerobic Digestion is receiving a great deal of attention as a viable alternative in supporting residuals management for livestock operations. In contrast to conventional liquid and slurry management systems, anaerobic digesters provide multiple environmental benefits such as odor control, improved air and water quality, improved nutrient management flexibility, and the opportunity to capture biogas for heat and electricity production. The digester system is a process which includes: collection and handling, anaerobic digestion, by-product recovery and effluent use, and biogas recovery and use. Although energy production alone has not been cited as the primary motivation for the installation of anaerobic digesters, state policies on distributed power pricing can greatly affect the economic viability of digesters. The model developed in this study incorporates a variety of system parameters to examine the economics of a digester system under three different electricity purchase agreements. The results suggest that making specific changes to Michigan's energy policy will improve digester return on investment over a range of herd sizes.

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Chapter 1: Introduction

Agricultural production in the United States annually discharges large amounts of nitrogen and phosphorus, some of which eventually end up in ground and surface waters. According to the Environmental Protection Agency (EPA), these nutrients from crop and animal production are found in 50% of impaired lakes and 20% of impaired rivers in the U.S. (Kaplan et al., 2004). As livestock operations continue to increase in size, one of the most significant challenges that producers face is managing manure and process water in a way that controls odors and protects environmental quality (U.S. EPA, 2002). In Michigan, state law limits the land application of manure based upon phosphorous levels and farms must find ways of handling the excess manure in order to avoid violations. In addition to the restrictions on the land application of manure, livestock producers are facing an increased risk of odor complaints as people move into rural areas (Safferman and Faivor, 2008). New residents are generally less tolerant of odors and the number of reported complaints has increased in recent years. In some cases, these actions may seek millions of dollars in damages and injunctions to close the operation (Miner, 1997).

As a result of these pressures, anaerobic digestion is receiving a great deal of attention as a viable alternative in supporting residuals management for livestock operations (MDA, 2009). The process itself involves the controlled breakdown of organic wastes by bacteria in the absence of oxygen (Lazarus and Rudstrom, 2007). In contrast to conventional liquid and slurry management systems, anaerobic digesters provide multiple environmental benefits such as odor control, improved air and water quality, improved nutrient management flexibility, and the opportunity to capture biogas for heat and electricity production (U.S. EPA, 2002). When properly running, a digester has the potential to turn a waste liability into a profit center that generates annual revenues and diversifies farm income (Lusk, 1998). "Farmers have found that the returns provided from electricity and co-product sales from the digester, however limited, are preferred to the sunk-cost of conventional disposal that provides zero return on investment. In addition, without the environmental benefits provided by digester technology, some might be forced out of livestock production and a digester is sometimes the only technology that allows growth in the livestock production business" (Lusk,1998, p. 1-2).

Anaerobic digestion, however, is not a new technology. During and immediately after the energy crisis caused by the oil embargo in 1973, many anaerobic systems were built to produce energy. At least 71 were installed on commercial livestock or poultry operations, but with lower energy prices many of these systems were abandoned. The limited long-term success in the United States can be attributed to poor system design, improper system installation, and unsatisfactory system management (Lusk, 1998). While interest in digesters was initially driven by energy concerns during the 1970's oil crisis, they are fairly capital-intensive when viewed primarily as an energy source (Lazarus, 2008). The cost for digesters varies depending on the design, an estimated \$500/cow to \$750/cow on average (NRCSa, Undated). As a result of this high capital investment, when considering the economics of anaerobic digestion, it is necessary to perform a thorough examination of potential revenue streams, system design and the extent to which it satisfies the objectives of the individual farm operator.

Although energy production alone has not been cited as the primary motivation for the installation of anaerobic digesters, state policies on distributed power pricing and interconnection can greatly affect the economic viability of digesters (Lazarus, 2008). Contractual agreements with utility companies tend to be of three types: "buy all-sell all," "surplus sale" and "net metering." The type of utility contract utilized may have a significant impact on digester economics and the specifics of each type of agreement vary depending on the utility company and state energy policy. According to a survey of 64 producers across the U.S. and 10 in California, negotiating these contracts were cited as the biggest challenge faced by the producer (Lazarus, 2008). In addition, some utilities impose "demand" or "standby" charges to pay for the availability of electricity to the farm when the digester system is not running. In many cases, difficulties related to negotiating with utility companies discouraged farmers from installing digesters that had been planned (Lazarus, 2008).

At the same time, the area of energy policy represents a significant opportunity to improve digester profitability. For example, Michigan has recently enacted a new Net Metering Law as part of Public Act 295 of 2008 which also specified a Renewable Portfolio Standard (RPS) requiring the state to produce 10% of its electricity from renewable sources by 2015. Although this is a step in the right direction for encouraging digester installations, even more favorable energy policies for anaerobic digesters could improve their economic feasibility and increase their adoption among farmers. Nationally, AgSTAR estimates that around 7,000 large dairy and swine operations could operate profitable biogas systems with a generating potential of 722 megawatts—0.1

percent of total U.S. electrical generating capacity or enough to supply almost 1 million homes (Lazarus 2008; U.S. EPA, 2006). As energy policy continues to develop, it is expected that the sale of Carbon Credits and Renewable Energy Credits will also increasingly contribute to digester revenues.

The focus of this research was to develop a model to examine the economics of anaerobic digestion under different policy and system design scenarios using capital budgeting methods. Among the policy options evaluated were different electricity purchase agreements as well as the impact of renewable energy credits (RECs), carbon credits and the value of electricity produced by the digester. Additional elements analyzed include the impacts of propane offsets and the co-digestion of added feedstocks. Although non-energy benefits are significant in the decision to install a digester, they have not been quantified in previous research and therefore are not included in this study.

The concept of a model to examine digester economics, however, has been explored in several other studies. Dr. Brent Gloy from Cornell University developed a financial analysis model of anaerobic digestion systems on diary farms along with a corresponding paper (Gloy and Enahoro, 2008). This model was illustrated with two sources of data; a "base" case using parameters developed from a wide range of sources and direct comparison with values calculated from the FarmWare 3.1 simulator[1]. The analysis includes many key digester parameters and examines the effects of financial incentives offered under the New York State Energy Research and Development Authority's Customer-Sited Tier Anaerobic Digester Gas-to-Electricity Program. Based upon

[1] Developed by the U.S. Environmental Protection Agency (EPA) AgSTAR Program (U.S. EPA, Undated)

estimates of the costs of a 1,000 cow dairy operation, the study found such a system to be only marginally profitable. A sensitivity analysis was then run under a variety of scenarios in which the profitability of the system was improved. In particular, increased biogas production and higher retail electricity prices resulted in a higher net present value (NPV) for the digester investment.

Gloy's model, however, does not account for potential seasonality in biogas production or other production related parameters such as: heat loss, parasitic energy requirements and variations in manure characteristics. It was also only programmed to consider profits under a "surplus sale" utility contract and ignores the cost of standby charges and other fees typically imposed by utility companies.

In a study out of Pennsylvania State University (Leuer et al., 2008) another model was developed which also compared the profitability of several digester scenarios. Similar to the study from Cornell, the scenarios examine the application of benefits realized by digester systems. In contrast to the study by Gloy, however, this model focused on the effect of the Pennsylvania net metering law and examined the added benefit of solids separation and the resulting revenues from either compost sales or livestock bedding offsets. Here, a stochastic capital budgeting model was used which incorporated Monte Carlo Simulations to derive the probability of the NPV being either greater than or equal to zero. The study also tested digester profitability under three herd sizes: 500, 1,000 and 2,000 cows. System income was valued in the form of electricity sales and offsets, bedding savings, separated solids sales, carbon credits and renewable energy credits. Non-energy benefits of the system, however, were not included.

The work showed that larger dairy farms, in the range of 1,000 or 2,000 cows, have the most potential to be profitable with a digester system. In addition, a solids separator to produce digestate for bedding as well as new policies and regulations can further increase profitability. Items such as the sale of carbon credits and Pennsylvania net metering regulations also affected the project's profitability but neither, by itself, turned an unprofitable scenario into a profitable one (Leuer et al., 2008). This study is valuable in its ability to illustrate the effects of state specific energy policy as well as a variety of system benefits and revenues. For example, it compared the revenues associated with the sale of digestate solids for compost and their possible use as a source of livestock bedding. On the other hand, it did not deal with the many variables affecting biogas production and examines only one type of electricity purchase agreement.

Yet another model was developed by Lazarus (Lazarus, UM), which helps users make rough initial calculations of the annual costs and returns associated with owning an on-farm anaerobic digester. The main issues it intended to address were: herd size, digester installation cost, amount and value of electricity produced, value of co-products and financing (e.g., grants). It does not, however, address engineering, design issues or expected biogas output.

A separate paper by Lazarus (Lazarus, 2003) is a case study of the Haubenschild demonstration digester in Minnesota which has exhibited relatively high biogas production levels compared to similar digesters (Lazarus and Rudstrom, 2003). Here, Lazarus constructed a model in Microsoft Excel with two main objectives. The first was to document the economics of the case farm's digester system utilizing actual data from the Haubenschild digester in Minnesota. The other objective was to compare the demonstration farm against future scenarios involving the installation of a digester. Scenarios for future digester installations included reduced biogas production, lower payments for electricity produced and decreased public funding when compared to the Haubenschild digester. Due to the detailed data recorded by the farm operator, an estimate of the various non-energy benefits was also examined including avoided pit pre-agitation, reduced herbicide costs and fertilizer benefits. The results highlighted the importance of non-energy benefits on digester profitability, particularly under scenarios with decreased production levels and reduced grant funding. The model in this study, however, was not developed as a decision support tool and did not predict monthly biogas production, capital costs or analyze different electricity purchase agreements. Instead, data recorded by the Haubenschild Dairy operator was input directly.

A study by Mehta (Metha, 2002) did not develop a model, but did attempt to examine optimal energy use and sale to utility companies based upon various electricity pricing scenarios. In particular, it explored the economics and feasibility of electricity generation using digesters on small and mid-size dairy farms. Essentially, the paper concluded that if the electricity sale price was greater than or equal to the purchase price, then larger farms would be able to make a larger profit margin on each kWh of electricity sold. They would gain more of a competitive edge through the introduction of a digester than smaller farms. Conversely, if the sale price is less than the purchase price, then farms would utilize generated electricity to offset their own electric bills with smaller farms experiencing a relative competitive edge since they can utilize more energy on-farm. Due to a lack of data, however, only rough conclusions or recommendations could be drawn from the analysis.

Although, several digester models have already been developed by various economists, the model developed in this research is unique in the following aspects.

- Provides flexibility for either direct input of data or values can be calculated by the model. As a result, analyses can be performed with minimal system details which increases its value as an outreach tool.

- Models biogas production on a monthly basis while accounting for heat loss, parasitic energy requirements, variations in manure characteristics and the possibility of co-digestion (to be further discussed in Section 2.12). Through this method, digester electricity production and performance is more accurately represented. Estimations of digester output also help to decide which electricity purchase agreement is most favorable for a given farm.

- Allows for evaluating engineering designs and changes in system parameters. This capability helps engineers to examine the effects of changes to on-farm operations.

- Estimates the capital costs of a digester (complete mix) based upon herd size. The ability to evaluate a range of herd sizes increases its value as a research tool since the effects of policy changes can be examined for all farm sizes that are potentially impacted.

- Compares three different electricity purchase agreement policies based upon actual utility rates and rules. Proposed changes in Michigan specific energy policy can then be evaluated.

The hypothesis of this study is that under current Michigan energy policy, an anaerobic digester is unlikely to show a positive return on investment based solely upon its energy benefits. On the other hand, it is expected that feasible scenarios exist in which the system could actually become a viable source of profit. The scenarios examined include changes in the prices of electricity, renewable energy credits and carbon credits as well as changes in digester performance parameters (e.g., operational online time, volatile solids loss, and total solids concentration). In addition, specific aspects of Michigan's energy policy are analyzed in hypothetical situations over a range of herd sizes. Recommendations are then made based upon the results in order to make current energy policies more favorable for anaerobic digesters.

Chapter 2: The Basics of Anaerobic Digestion

The purpose of this chapter is to provide an overview of anaerobic digestion from the microbiological level to more specific engineering concepts and policy issues. Chapter 3, which describes the specifics of the model, builds upon the material covered in the following sections.

2.1 The Microbiological Process

Anaerobic digestion is the breakdown of animal manure by bacteria in the absence of oxygen resulting in the production of biogas (Bracmort et al., 2008). "It tends to occur naturally wherever high concentrations of wet organic matter accumulate in the absence of dissolved oxygen. Most often, this is in the bottom sediments of lakes and ponds, swamps, peat bogs, intestines of animals, and in the anaerobic interiors of landfill sites" (Lusk, 1998, p. 2-1). As a technology, it has been around for centuries with anecdotal evidence indicating that biogas was used for heating bath water in Assyria during the 10th century B.C. and in Persia during the 16th century B.C. (Lusk, 1998). The nation's first farm-based digester, however, wasn't initiated until 1972 and was constructed as a response to urban encroachment (Lusk, 1998). During the 1970's, a number of digesters were constructed, but many failed due to poor system design, improper system installation and unsatisfactory system management. Since around 1984, however, digester designs have improved (Lusk, 1998). The need for odor control and residuals management combined with these improved designs has led to a recent resurgence of interest in anaerobic digester technology. According to the EPA AgSTAR program, there are currently 135 operational digesters in the U.S.

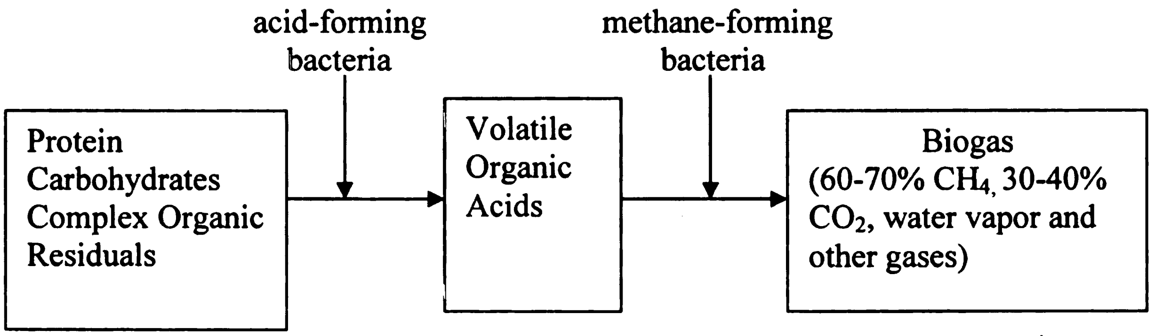
The biogas produced in anaerobic digestion is the result of microbial degradation of carbon-containing compounds. These compounds are present in all organic matter (all cells, living and dead) and are often measured as volatile solids (VS). VS is a standard measurable parameter that allows different types of organic substances to be compared for degradability. Higher levels of volatile solids indicate that the material has more organic carbon and may be more degradable. Therefore, the amount of biogas that can be produced is directly proportional to the amount of volatile solids in the feedstocks being digested (Crook and Gould, 2009). Another frequently used term is total solids (TS). In contrast to the VS measurement, it accounts for all solids including both the volatile and non-volatile compounds and elements.

The anaerobic digestion process can occur at a wide temperature range, but generally occurs at either the mesophilic (95°-105°F) or thermophilic temperature ranges (125°-135°F) (Lusk, 1998). First, the volatile solids in manure are broken down to produce a series of fatty acids. This step is called the acid-forming stage and is carried out by a group of bacteria called acid formers.

In the second stage, a highly specialized group of bacteria, called methane formers, convert the acids to biogas (Fulhage et al.,1993). "These bacteria are slower growing than acid-forming bacteria and are extremely ph-sensitive (pH 6.8-7.4 optimum). The acid formers will grow rapidly if an excess of organic material is fed to a digester, producing an excess of volatile acids. If this happens, the accumulated acids will lower the pH, inhibiting the methane bacteria and stopping gas production. To help buffer the system against increases in acids, high alkalinity must be maintained. Lime can be added to digesters during start-up periods of slug loading to maintain pH control" (Fulhage et al., 1993, p. 1). In addition, a variety of materials such as salts, heavy metals, ammonia and antibiotics can become toxic to anaerobic bacteria and must also be carefully monitored (Fulhage et al., 1993).

The resulting biogas is a combination of methane (60-70%), carbon dioxide (30-40%), water vapor and trace amounts of other gases such as hydrogen sulfide (H_2S) (US EPA, 2002). H_2S is very corrosive and can cause damage to engines, boilers and other digester components. Only the methane component of biogas has energy value.

Figure 1. Simplified Process of Biogas Production



2.2 The Digester System

The digester system is a process which includes collection and handling, anaerobic digestion, by-product recovery and effluent use, and biogas recovery and use. There is significant variability in digesters from one farm to another and it is difficult to make generalizations and comparisons.

2.2.1 Collection and Handling

The starting point for a digester system is manure collection and handling, with the key considerations in the system being the amount of water and inorganic solids mixing with the manure. With dairy farms, the manure is generally scrape collected from freestall barns two or three times a day. Following collection, the manure may undergo pretreatment prior to introduction into the digester. The pretreatment involved varies depending on the farm and the type of digester technology used and may consist of screening, sand and/or grit removal, mixing and/or flow equalization (Krich et al., 2005). Some forms of pretreatment (e.g., sand removal), however, may not be beneficial to energy production as a portion of the volatile solids which produce biogas are removed (Burke, 2001).

At this point in the process, water from the milking parlor and other sources may be added in order to dilute the manure, but this varies from farm to farm and the solids requirements of the digester. "Dilution also reduces concentrations of nitrogen and sulfur which convert into ammonia and hydrogen sulfide during anaerobic digestion. Ammonia is inhibitory to the process and hydrogen sulfide is an undesirable component in biogas due to its highly corrosive characteristics" (Burke, 2001).

2.2.2 Anaerobic Digestion

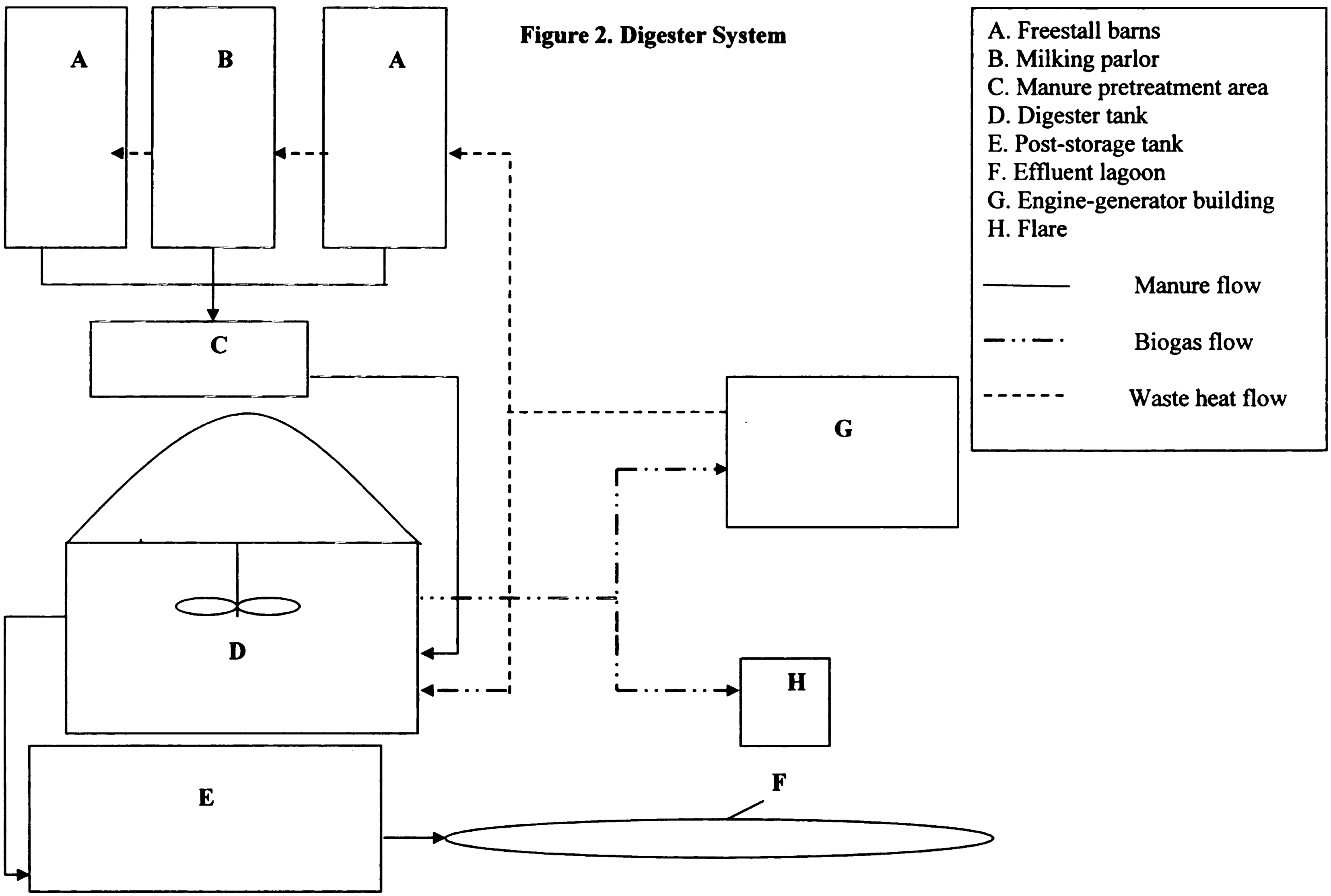
After pretreatment, the manure along with any added water is pumped into the digester. Manure characteristics and collection technique determine the type of anaerobic digester technology used. U.S. livestock operations currently use four types of anaerobic digester technologies: plug-flow, complete-mix, fixed film and covered lagoons (Lusk, 1998). "However, the parameters of any waste management system are site-specific and may vary significantly from one livestock operation to the next. Effective implementation of anaerobic digestion technology, therefore, demands that the digester be integrated with the existing or planned manure management system. This requires an understanding of the technology and of the impact that other site-specific management practices can have on both the energy potential of the feedstock and the efficient operation of the digester unit" (Wilkie, 2005, p.311-312). For these reasons, few generalizations or comparisons can be made between digesters and each system must be evaluated on a case by case basis. In this study, the model is based on the use of a complete mix digester since they are the best suited for Michigan's climate. Figure 2 is a representation of a typical complete digester system.

2.2.2A Complete Mix

Complete-mix digesters can handle manures with TS concentrations of 2.5%-10%[2], and generally can handle substantial manure volumes. "The reactor is a large, vertical, poured concrete or steel circular container and the manure is collected in a mixing pit by either a gravity-flow or pump system. If needed, the TS concentration can be diluted, and the manure preheated before it is introduced to the digester tank. Within the digester, the

[2] (NRCSb, 2005)

Figure 2. Digester System



manure is mixed creating a homogeneous mixture that prevents the formation of a surface crust and keeps solids in suspension. Mixing is important to ensure contact between the bacteria and the waste and also to help release gas out of the liquid. Complete-mix digesters can operate at either the mesophilic or thermophilic temperatures range with a hydraulic retention time (HRT) of 10-20 days" (Lusk, 1998, p. 2-7). HRT refers to the average length of time that a particle of manure or other feedstock remains in the digester.

"A fixed cover is placed over the complete-mix digester to maintain anaerobic conditions and to contain the biogas that is produced. The biogas produced is then removed from the digester, processed, and transported to the site of end-use application. The most common application for methane produced by the digestion process is electricity generation using a modified internal combustion engine" (Lusk, 1998, p. 2-7).

2.2.3 By-Product Recovery and Effluent Use

Once digestion is complete, it is possible to recover digested fiber from the effluent of some dairy manure digesters with the use of a solid/liquid separator. This material can then be used for livestock bedding, sold as a soil amendment or marketed for other uses. The effluent (either separated or non-separated) can also be used as a high value fertilizer. A further discussion on the benefits of digester effluent and separated solids is included in Section 2.13 "Non-Energy Benefits."

2.2.4 Biogas Recovery

"The composition and digestibility of the manure is the primary determinant of maximum methane yield (Wilkie, 2005, p.306)." "Biogas formed in the anaerobic digester bubbles to the surface, is collected (typically with plastic piping), and then directed to gas handling subsystems (Krich et al., 2005). "It is then pumped or compressed to the operating pressure required by specific applications and then metered to the gas use equipment" (Krich et al.,2005, p. 30).

2.2.7 Biogas Use

Recovered biogas can be used directly as fuel for heating, combusted in an engine to generate electricity, upgraded to natural gas or flared (Krich et al., 2005). Since biogas is only roughly 60-70% methane it has a lower energy content that either natural gas or propane. "With equipment modifications to account for its reduced energy potential and other constituent components, however, biogas can be used in all energy-consuming applications designed for natural gas or propane (Lusk, 1998, p. 2-11)." Sending biogas to a flare to be burned is considered the least attractive option for biogas since it does not generate energy revenues for the farm. Carbon credits may be possible, however, depending on the amount that is flared (Section 2.11). In general, flaring is limited to disposing excess biogas which cannot be used by the engine-generator as a result of downtime or overproduction.

2.2.7A Electrical Generation

Most farm-based digesters use the biogas output to generate electricity (Lazarus, 2008). The most common electrical generator system used at farm biogas facilities today is a stationary internal combustion engine that has been modified to 1.) run on biogas, 2.) drive a generator and 3.) produce single or three phase electrical power (Ciolkosz et al., 2009). An induction generator is generally used since it can run off the signal from the utility and will allow parallel hook up with the grid (Lazarus, 2008).

In the process of electric production, the exhaust from internal combustion engines (waste heat) can be used to pre-heat and maintain the temperature of the manure. Since electricity production is only roughly 35% efficient, the remaining 65% could be characterized as "waste heat." (Gebremedhin, 2006). "Usually, the equipment installed for capturing this waste heat consists of a heat exchanger and recirculating pump connected to a system of pipe lines immersed in hot water which deliver raw slurry or feedstocks to the digester. Another system of pipe lines then pick up slurry from the digester and return it to the heat exchanger to be recirculated" (Crook and Gould, 2009, p.45).

Due to the high hydrogen sulfide (H_2S) content of biogas, engine-generators may require more frequent maintenance. Biogas from dairy manure typically contains 0.2-0.4% hydrogen sulfide H_2S (Jones et al., 1980). "The sulfuric acid from the H_2S can accumulate in the engine oil, resulting in accelerated corrosion and early failure of engine components. As a result, engine oil from biogas generators must be changed more often which results in higher operation and maintenance costs. Some digester systems may even purchase an H_2S scrubber to extend the life of the generator. An oil analysis can also be valuable tool for assessing the condition of the oil and can alert the operator to engine problems before they cause serious damage (Ciolkosz et al., 2009). Electrical generation equipment can be very expensive, however, and some operators who have installed digester systems are unable to recoup the installation and operation costs through the sale of electricity (Beddoes et al., 2007). An analysis of 38 existing U.S. manure anaerobic digestion systems indicates that 36% of the total cost of the system is attributed to the electrical equipment (Bracmort et al., 2008). Due to this high capital cost, digesters which produce electricity are generally only feasible on larger farm operations. Recent studies have shown that a herd size of around 800 cows to be the lower limit (Jewell et al., 1997). The EPA AgSTAR program estimates this number to be approximately 500 (U.S. EPA, 2002).

2.2.7B Key Considerations

From an engineering perspective, there are also several key considerations that must be taken into account to determine the feasibility of installing an anaerobic digester. In terms of electricity production, the first element is calculating the energy demand of the digester. In order to accomplish this, there are two major energy requirements that must be analyzed: 1.) the amount of energy to bring the influent manure up to the digester operating temperature, and 2.) the amount of energy required to maintain the digester at the operating temperature. (Gebremedhin, 2006). The optimal temperature is maintained by using either waste-heat captured off the engine-generator or biogas which is used to run a boiler. If heat loss exceeds the waste heat produced from the engine-generator, then biogas must be diverted from electricity production to the boiler.

Two main performance parameters which affect the amount of biogas used in the boiler are the total solids concentration and the loss of volatile solids. A low total solids concentration means that higher amounts of water are present in the influent which increases the heat requirements to maintain the optimal digester temperature. In the case of volatile solids loss, the energy potential of the influent is reduced which decreases biogas production. Decreased biogas production results in less waste heat capture from the engine-generator and therefore increases the need to use a boiler to maintain the optimal digester temperature. The overall result in both situations is that electricity production form the digester system decreases.

Another key consideration is the type of animal bedding used. For example, with sand bedding, the sand-laden manure presents a problem for conventional digester designs. This is because the sand will settle out in the digester, reduce digester volume and create excessive wear on components. Over time, the HRT along with the biogas yield will be reduced (Wilkie, 2005). "Mechanical sand-manure separators, however, can extend the potential application of anaerobic digestion to scrape operations using sand bedding. During the sand-separation process, dilution water is added which produces a sand-free manure stream of low solids content more similar to flushed manure"(Wilkie, 2005, p.310). In addition to sand, other bedding materials have been identified as potentially troublesome to digester function such as large amounts of straw and wood shavings (Steffen et al., 1998).

2.2.7C Other Energy Uses

"Given the increase in natural gas prices over the past five years, the direct use of biogas as a replacement for natural gas or propane for on-site heating purposes (e.g., heating water, heating animal housing, etc.) would provide economic benefits to animal producers with a consistent year-round requirement for the biogas. The direct use on the farm for biogas produced via a manure anaerobic digestion system appears to be economically feasible when the on-farm heating requirement are high enough to utilize the biogas produced by the system" (Bracmort et al., 2008, p.1). The energy utilized for the natural gas/propane offsets can come either from waste heat (if using electrical engine generator) or be taken directly from the biogas production once the digester heating requirements are met. In both cases, the energy is used to heat water which would typically be accomplished with either propane or natural gas in the absence of the digester.

"As with electrical engine generators, boilers are also adversely affected by the corrosive characteristics of biogas. One way around this problem is to operate the boiler continuously at a temperature above dew point" (Beddoes et al., 2007). This is because it prevents sulfuric acid (H_2SO_4) from forming which causes corrosion. If the boiler is only used on an "as needed" basis, however, this may not be an effective strategy. "It should also be noted that most farm heat requirements are seasonal and the problem of how to best use the gas in the "off" season must be dealt with. Storage of the gas in large amounts is largely impractical because of the relatively low heat value of methane (compared to propane and other liquid fuels) and its difficulty to liquefy under reasonable pressures. Most storage applications would likely involve only short-term accumulations of methane (Fulhage et al., 1993, pp. 4, 7)." This is a main reason why biogas is generally consumed on-site continuously either for electricity production or for heating needs.

Biogas can also be upgraded to biomethane for retail sale by processing it to remove moisture, H_2S and CO_2, none of which possess any energy value. In order to be economical, the cost of upgrading must be less than the incremental difference between the biogas and natural gas cost (Bracmort et al., 2008). Currently, this is not a routine practice on dairy farms and therefore biogas upgrading was not examined in this study.

2.8 Annual Operation and Maintenance Costs

For digesters with electrical equipment, "Operation and Maintenance (O&M) costs include daily operator labor to pump the manure and perform routine maintenance; expenses for engine oil changes and minor repairs; and periodic major repairs and maintenance such as engine overhauls, sludge removal, and flexible cover repair or replacement" (Bracmort, 2008, p.8). In addition, all digesters require some management and labor to control the process. Successful operation for a typical on-farm digester will require a minimum of 1-2 hours per day for monitoring, loading, unloading and performing general maintenance (Jones et al., 1980). This estimate will vary depending on the digester design and may fluctuate in times of repair and overhaul.

2.9 Electricity Contracts

"Producing electricity is only part of the challenge with making an anaerobic digester cost effective. In particular, selecting a favorable electricity purchase agreement is vital and has a significant impact on the profitability of the digester system. In some cases, variables such as the number of different electricity meters may limit the farm's ability to utilize electricity on-farm where it has the highest value. Specific requirements for insurance, demand charges for the use of electricity when the on-site generator is down", and other rules may also make it difficult to deal with the utility company (Wright, 2001, p.10). Electricity contracts for anaerobic digesters are of three types: surplus sale, buy-all sell-all and net metering. While the specifics of each will vary depending of the power provider, the basic concept behind each agreement is the same. The EPA AgSTAR handbook also makes reference to these three agreements and provides sample contract language for reference. In this study, the purchase agreement specifics were taken from a Michigan utility which has been involved with several digester projects in the state.

2.9.1 Surplus Sale

The concept of a surplus sale agreement is that only excess electricity production is sold back to the utility company. Under this agreement, the farm will first utilize their electricity on-site where they have the ability to offset their usage at the retail rate. The amount of energy available for resale will then depend on the rate at which biogas can be produced on a continuous basis as well as the amount and timing of electricity use for the farm's dairy operation (the load curve) (Mehta, 2002).

According to the Department of Energy (DOE) Energy Information Administration, the rate (commercial) at which electricity is offset is approximately $0.09[3] nationwide. Any electricity that is sold back to the utility, however, is valued at the hourly real-time locational marginal price (LMP) of the particular utility's load node as determined by the Midwest Independent Transmission System Operator (MISO). MISO manages one of the world's largest energy markets using complex computer programs. The prices obtained from MISO represent the wholesale price of electricity and tend to be roughly half of the retail rate on average. Upon examination of historical prices, the LMP fluctuates with demand and can even be a negative value during certain periods. This is due to the fact that the utility cannot shut down its operations in times of lower demand. During these periods, the farm would actually be paying the utility to put their electricity on the grid.

In addition, depending on the particular rate plan for customer generation, some utilities will impose an administrative charge per kWh for the purchase of the electricity from the power provider as well as a system access charge. The administrative charge compensates the utility company for time and labor time associated with administering the agreement. Minimum and maximum monthly charge amounts are also stipulated in the purchase agreement and are adjusted for inflation based upon consumer price indexes from the U.S. Bureau of Labor and Statistics. The system access charge recovers the

[3] This price does not include inflation.

costs of metering equipment, meter reading, billings and other customer-related operating costs.

An interval data meter is usually required for the utility to monitor the customer's generator and electricity flow. The company typically reads the meter electronically via telecommunication links or electronic data methods to obtain the information needed for billing.

Generally, standby charges will also apply if the farm wishes to purchase electricity from the utility when their engine-generator is down. Standby charges have been cited as a significant obstacle when a farm attempts to offset their energy use with electricity produced from their engine-generator. The concept is that these charges are used to compensate the utility company for providing electricity when the digester engine-generator is not running.

A typical digester engine-generator with "good" performance will generally be operational 90% of the time (U.S. EPA, Undated). This means that the farm will need energy from the utility the remaining 10% of the time or when peak demand exceeds digester output. The specifics of standby service will vary depending on the utility company, but generally are composed of two parts, power supply and delivery standby charges. Power supply refers to the cost of fuel and power producing investments. Delivery charges compensate the utility for transporting the electricity from the plant to the customer.

2.9.2 Buy-All Sell-All

Under this agreement, all electricity produced by the digester is sold to the utility. The farm must then purchase all their electricity needs from the utility at the applicable retail rate. As with the surplus sale, the rate of compensation by the utility is the hourly real-time LMP. At first, this may appear to be an inferior agreement when compared to the surplus sale. The tradeoff, however, is that standby charges do not apply since no on-farm energy usage is being offset by the digester system. On the other hand, any energy demand created by the digester system itself will need to be purchased from the utility and would represent an incremental project cost. As a result, this cost must be considered in the capital budgeting analysis and can have a potential impact on the economics of this agreement depending on the amount of energy used by the digester. In addition, the same guidelines for system access and administrative charges will apply as under the surplus sale agreement.

2.9.3 Net Metering

With the passing of Michigan Public Act 295 in October of 2008, a new net metering law was approved by the state legislature. The concept of net metering is that the utility allows a customer to offset only their electrical "need" and receive credits for any energy produced which exceeds that need. When a customer is under a demand based rate system, the electrical need is usually established based upon the peak demand over a twelve month period. If that information is not available, an appropriate level is negotiated with the utility. This limits the engine-generator size that can be used with a net metering agreement, since a typical complete mix digester in Michigan is capable of producing more electricity than the need of the farm. Without the use of net metering, a farm would normally use an engine-generator sized to match the full biogas production potential of the digester system.

Another distinguishing aspect of net metering agreement is that fact that no actual payment is made for the electricity produced by the customer. The revenue is represented by the electricity purchases offset by self-generation and the credits which can be carried over from month to month. Most utilities, however, will put a cap on the period of time that credits can accumulate (e.g., one year). Net metering is not intended to be a profit making mechanism for the digester owner.

Under Michigan law, net metering consists of four main categories based upon the nameplate capacity of the generator. For digester projects, only categories 2 through 4 will realistically apply.

- Category 1- projects ≤20 kW
- Category 2- projects >20 kW and ≤150 kW
- Category 3- projects >150 kW and ≤550 kW
- Category 4- projects >550 kW and ≤ 2 MW
- Category 5- projects > 2 MW

While net metering is not a new concept, Public Act 295 made the agreement more favorable for category 1 projects such as small wind and solar. For projects in category 1, the utility will credit the customer for their excess generation at the retail rate, which is referred to a "true" net metering. On the other hand, categories 2-5 receive "modified" net metering in which customer credits are valued at either the monthly average LMP (similar to the surplus sale agreement) or the power supply component[4] of their electric bill. While the act signed into law gave utilities the choice between the two pricing schemes, recently published utility guidelines from the largest Michigan utilities indicate that they have chosen to compensate at the power supply component price. The power supply component of the customer's bill is approximately $0.06 whereas the monthly average LMP is roughly $0.04. While not as favorable as "true net metering," the higher value for electricity produced by the digester system represents an improvement on previous policies.

There are also other benefits of the new net metering for digester projects. One benefit is a provision that category 2 projects do not pay standby charges. Additionally, category 3 projects do not pay standby charges unless the engine-generator used has a nameplate capacity greater than 150 kW. At the current time, however, the specifics of standby charges under the net metering law have yet to be established. In the absence of specific rates, standby charges are assumed to be the same as under the surplus sale agreement. Another benefit is that category 2 projects do not incur the cost of any additional metering equipment. Also, there is no mention of system access or administrative charges for projects in categories 2 or 3. In contrast, surplus sale and buy-all sell-all agreements are subject to these charges.

[4] The power supply component refers the cost of fuel and power producing investments.

2.10 Renewable Energy Credits

If a farm with a digester generates alternative energy, it can receive a Renewable Energy Credit (REC) for every megawatt hour (1,000 kWh) of energy it produces (Leuer et al., 2008). Farms in Michigan may sell these to utility companies, if allowable under contract, or sell them as carbon credits (as explained in section 2.11). A farm may still sell RECs to one utility and have a purchase agreement established with another. RECs are completely separate form electricity purchase agreements and represent different revenue sources.

As a result of the recent Renewable Portfolio Standard, PA 295, a number of Michigan utility companies are currently seeking RECs in order to comply with the new law. Recent contracts from large Michigan utility companies indicate that RECs in the future will be purchased for \$30 to \$50 per credit (1,000 kWh).

2.11 Carbon Credits

Carbon credits have the potential to be an essential revenue stream for an anaerobic digester system. This model is based upon the rules established by the Chicago Climate Exchange (CCX), which is North America's only active voluntary, legally binding integrated trading system to reduce emissions of all six greenhouse gases (GHG's) (CCXa, 2009). Credits are issued based upon an emission baseline calculation which calculates the amount of methane that would be emitted to the atmosphere during the crediting period in the absence of the anaerobic digester project (CCXa, 2009).

There are two methods to calculate the baseline methane emissions. The first is by the actual monitored amount of methane captured and destroyed by the project activity using existing CCX monitoring protocols and a global warming potential (GWP) for methane of 21. The GWP for a particular greenhouse gas is defined as the ratio of heat trapped by one unit mass of the greenhouse gas to that of one unit mass of carbon dioxide (CO_2) over a specified time period. The second is calculated "Ex Ante" which refers to the amount of the animal manure that would decay anaerobically in the absence of the project activity. CCX calculates the amount of methane destroyed or avoided using the method which results in the lowest level of methane. Each credit traded represents a reduction of one metric ton of carbon dioxide (CO_2) and the value of each credit fluctuates with the current market price. For example, in the summer of 2007, the price of a carbon credit was roughly \$7.50. In contrast, the price dropped to only \$0.25 in the summer of 2009.

In order to receive carbon credits, certain guidelines also apply which place certain requirements on participants. The guidelines (CCXb, 2009) applicable to anaerobic digesters are highlighted below.

- Only renewable energy systems activated on or after January 1, 2003 qualify.
- Project proponents need to demonstrate clear ownership rights of the emission reductions from the destruction of methane.
- All projects must be independently verified by a CCX-Approved Verifier. Specific guidelines on the equipment and record keeping required are specified in the agricultural methane offset protocol.

A detailed description of the calculation of carbon credits is included in Chapter 3.

2.12 Co-digestion

While livestock manure is the main feedstock for farm-based digesters, other feedstocks (e.g., crop residues, leaves, food processing waste, ethanol syrup) can be added to potentially increase biogas production (co-digestion). The goal of co-digestion is to maximize the amount of carbon in the mixture while staying within the correct C: N ratio. The overall nutrient ratio in waste materials is of major importance for the microbial biodegradation process (Steffen et al., 1998).

Large amounts of agricultural raw materials are processed in the food industries. During processing, wastes and wastewater are produced which can often be co-digested in agricultural digesters (Steffen et al., 1998). Not every feedstock, however, is suitable for anaerobic digestion. They vary considerably in composition, homogeneity, fluid dynamics and biodegradability. When selecting wastes for digestion, the total solids content, the percentage of volatile solids, the C:N-ratio and the biodegradability have to be carefully considered (Steffen et al., 1998). For farm-based anaerobic digesters, mainly feedstocks that have characteristics (moisture content, total solids, etc.) similar to animal manure should be considered for anaerobic digestion (Scott and Ma, 2004).

Due to the variability among digester systems, no established guideline exists for the best percentage of feedstock to mix. Some anaerobic digesters have been built to process 100% food waste and the perception is that it is possible to go as high as 75% (Scott and

Ma, 2004). In contrast, however, the Ministry of Agriculture, Food and Rural Affairs in Ontario, Canada recommends that a farm-based digester can only blend up to 10-25% non-farm source material and work effectively (Ontario, 2009). In general, gradual loading of the digester can give the system time to adjust to the new feedstock and proper maintenance can help to prevent most problems associated with co-digestion (Scott and Ma, 2004).

"Non-farm industries that have organic wastes to dispose of will sometimes pay tipping fees to a farm digester to accept the waste. For the digester enterprise, the tipping fees can be an important side benefit of accepting this feedstock, making the difference between profit and loss. A concern, however, is that on livestock farms with small land bases, the livestock manure alone may already have too much nitrogen and phosphorus for the cropland available. Imported non-farm organic wastes would contain additional nutrients, which could exacerbate the cropland nutrient imbalance. The tipping fees and added gas output need to be weighed against potentially greater manure disposal costs to take the effluent to more distant cropland" (Lazarus, 2008, p.15). The model in this study allows the user to account for this potential tradeoff between increased gas production and increased disposal costs.

It may also be the case that a farm decides to purchase non-farm organic wastes (e.g., ethanol syrup), in which case no tipping fee is received. In this situation, the farm incurs the cost per unit for the feedstock purchase and possibly the hauling cost from the point of pickup to the farm. The final disposal cost will be a function of the amount of solids remaining after digestion and the distance to the disposal site (either to a landfill or for land application). The benefits of increased biogas production, however, may justify the increased costs depending on the situation.

With co-digestion, it is also important to be aware of any applicable state laws which may prohibit or place restrictions on the mixing of non-farm organic waste with livestock manure. In Michigan, the Michigan Department of Environmental Quality (MDEQ) has issued an "Organic Residuals Exemption" for on-farm anaerobic digestion. It only allows food processing residuals (as defined in Section 324.11503(9) of Part 115 in the Natural Resources and Environmental Protection Act (NREPA)), syrup from ethanol production and fish wastes to be added. Any other materials used must receive written approval by the MDEQ.

Per NREPA, "Food processing residuals" means any of the following:

(a) Residuals of fruits, vegetables, aquatic plants, or field crops.

(b) Otherwise unusable parts of fruits, vegetables, aquatic plants, or field crops from the processing thereof.

(c) Otherwise unusable food products which do not meet size, quality, or other product specifications and which were intended for human or animal consumption.

The approval, however, is limited to a maximum 20 percent substitution rate, by volume, of the material going into the digester unless an alternative substitution rate is approved in writing. Digester operators must also be approved by the MDA as a "Certified

Operator for Agricultural Anaerobic Digesters." Other provisions and permit requirements under NREPA pertaining to air, water and hazardous waste are not exempt.

Specifically in regard to land application, the digester effluent (digestate) may be land applied provided several conditions are met (MDEQ, 2009).

1.) "The owner/operator must ensure that the digestate is managed according to the Nutrient Utilization Generally Accepted Agricultural Management Practices (GAAMPS) or the Manure Management GAAMP developed under the Right to Farm Act."

2.) "The operator of the farm must ensure that the concentration of contaminants in the soil, after land application, shall not cause the creation of a "facility" as defined by Part 201, Environmental Remediation, of the NREPA."

3.) "If the digestate is not used on the farm where it was generated, it must then be licensed with the MDA under Part 85, Fertilizers, of the NREPA."

This organic residuals exemption represents a recent change in the state's previous policies regarding the co-digestion of waste for on-farm anaerobic digesters.

2.13 Non-Energy Benefits

Benefits unrelated to the production of heat and electricity are present yet not always easily quantifiable. The process of digestion itself converts volatile organic compounds in manure to more stable forms that can be land-applied with fewer objectionable odors (Lazarus, 2008). For example, if the manure is spread on the operator's own cropland, the reduced odor potential may have economic value to the livestock operation by minimizing the chance of neighbors' complaints or nuisance lawsuits. The reduced odor of the digestate itself may make it more marketable to crop farms (Lazarus, 2008). Quantifying this value has been notoriously difficult, however, since factors unique to an individual farm will determine the exact value of the odor reduction. In Kramer's Anaerobic Digester (AD) casebook nearly all the system owners mentioned odor reduction as an important benefit of their AD system (Kramer, 2004). For new farms, some means of odor control is often either implicitly or explicitly required for the facility to be sited and built. Some owners of ongoing operations reported that the encroachment of residential developments near their farms have put increasing pressure on them over time (sometimes in the form of lawsuits) to reduce odor emissions (Kramer, 2004). Because digested manure (digestate) has much lower odor than raw manure, owners also have more flexibility in when and where they field-apply it (e.g., they do not have to wait until the wind is blowing the right way or avoid applying it on weekends) (Kramer, 2004).

In addition to odor control, increased flexibility of nutrient management is also cited among the non-energy benefits of anaerobic digestion. "Nearly all animal manures are land applied, which means that some of their nutrient value is returned to the soil for plant growth. However, much of the nutrient value contained in manure can be lost before it is recycled or before the nutrients can be presented in a plant usable form" under traditional manure handling practices" (Lusk, 1998, p. 2-16). Since digestate is in a more stable form, crops are able to absorb more nutrients from the manure which increases its value as a substitute for commercial fertilizer. The increase in uptake reduces the possibility of nutrient run-off into surface waters given proper land application (e.g., direct soil injection) (MDA FAQ, 2009). Pathogens in digested manure are also reduced by as much as 99.99% (Lusk, 1998).

Further benefits are also possible through the use of mechanical solids separation. For example, the digestate solids (biofibers) can be utilized as a bedding material in dairy farm free-stall barns, sold as a soil amendment or used in other applications such as: the production of construction products (wall board), decking, and greenhouse pots (Safferman and Faivor, 2008). The solids separation is also made easier after the digestion process.

Since separated solids have less volume, they can also be hauled to fertilize distant fields at less cost than hauling the original manure (Lazarus, 2008). The phosphorus portion of the manure is also primarily sequestered in the solids which aids in residuals management. In contrast, the liquid fraction (filtrate) is high in nitrogen and low in phosphorus thus enabling irrigation of fields that may be phosphorus limiting. The filtrate is also low in volatile fatty acids and therefore does not stick to the leaves and can be spread on growing plants (e.g., on corn as tall as 20 inches) with only minor risk of burning (Lusk, 1998). Studies which quantify the amount of these benefits are not presently available.

One concern about using digestate solids as bedding, however, is that pathogens might remain to cause increased mastitis problems (Lazarus and Rudstrom, 2007). Although, the Agricultural Biogas Casebook cites various examples of farms utilizing digestate solids without adverse effects, "the literature review suggests that more research is needed to clarify the impact of bedding type on mastitis, in the context of the many management factors on a typical dairy farm" (Lazarus, 2008, p. 16). Although solids separation is easier (e.g., reduced use of chemicals) with digestion, the benefits of solids separation can also be achieved without incorporating a digester in the system. For that reason, the AgSTAR digester protocol recommends setting boundary conditions for digester evaluations that leave out the separator part of the system (Martin, 2006). For these reason, the model developed for this study does not include the use of a solids separator or the use of digestate solids as livestock bedding.

Chapter 3: The Model

The model developed in this study has two distinct functions. The first is its use as an outreach tool with a variety of modules allowing for the analysis of existing systems as well as those in the planning stage. In the absence of specific information, its default value modules allow the user to assume the initial cost of investment, operation and maintenance (O&M) costs as well as monthly biogas production. In order to construct the default value investment module, the budget from a large Michigan dairy farm was used as a reference. Component line items were estimated as either a percentage of total costs or sized based on related elements of the digester system. Other modules such as O&M costs and biogas production were based upon values from the published literature.

If data is available from an operational system, these same values may be input directly. In terms of biogas production, a separate module is included for the addition of feedstocks which can increase output and improve digester profitability. Biogas production is then converted into revenue streams under surplus sale, buy-all sell-all and net metering electricity purchase agreements. RECs, carbon credits and potential propane offsets are also included as typical sources of income which may be available for on-farm digesters.

Due to the high capital costs of an anaerobic digester, a separate module is used to account for the various financing options which generally come as a combination of grants, loans and equity. All revenues and expenses are then analyzed in a capital budgeting model using net present value, internal rate of return and simple payback period methods. The user can then alter the various system parameters to examine performance under current and hypothetical circumstances.

A second purpose for this model, and the primary focus of this study, is its use as a research tool to analyze energy policies as they relate to anaerobic digesters. Three different Michigan utility purchase agreements (surplus sale, buy-all sell-all and net metering) are examined in detail with rules and rates taken directly from one of the state's largest utility companies. Of special interest is the new net metering law and its effect on the economics of a typical digester in Michigan. While customers installing small wind and solar systems clearly benefit under this law, it is unclear how it compares to the other electricity purchase agreement options currently offered by utility companies. Also related to energy policy is the issue of standby charges. According to the literature, these charges are a major obstacle when using a digester to offset on-farm electricity use. Since the rules for standby charges are often rather complex, however, very little information is available which analyzes their impact on digester profits. The high cost of interconnection is also recognized as a barrier for digester owners, but an analysis of the details of interconnection is beyond the scope of this study. The primary research focus of this paper was a comparison of the three different electricity purchase agreements including standby charges under a variety of scenarios for a representative Michigan dairy farm.

This chapter explains the details of the model using an example dairy farm with a lactating herd of 1,000 Holstein cows. The model also assumes the digester to be a complete mix design with a total solids content of 8% and a hydraulic retention time (HRT) of 20 days. Data related to on-farm energy usage and investment costs were taken from the Michigan case farm and scaled to match the needs of the 1,000[5] cow example dairy farm for analysis. Examples are provided with each equation to illustrate the included formulas. Figure 3 illustrates the layout of the modeling process.

[5] dry cows and young stock not included

Figure 3. Model Layout

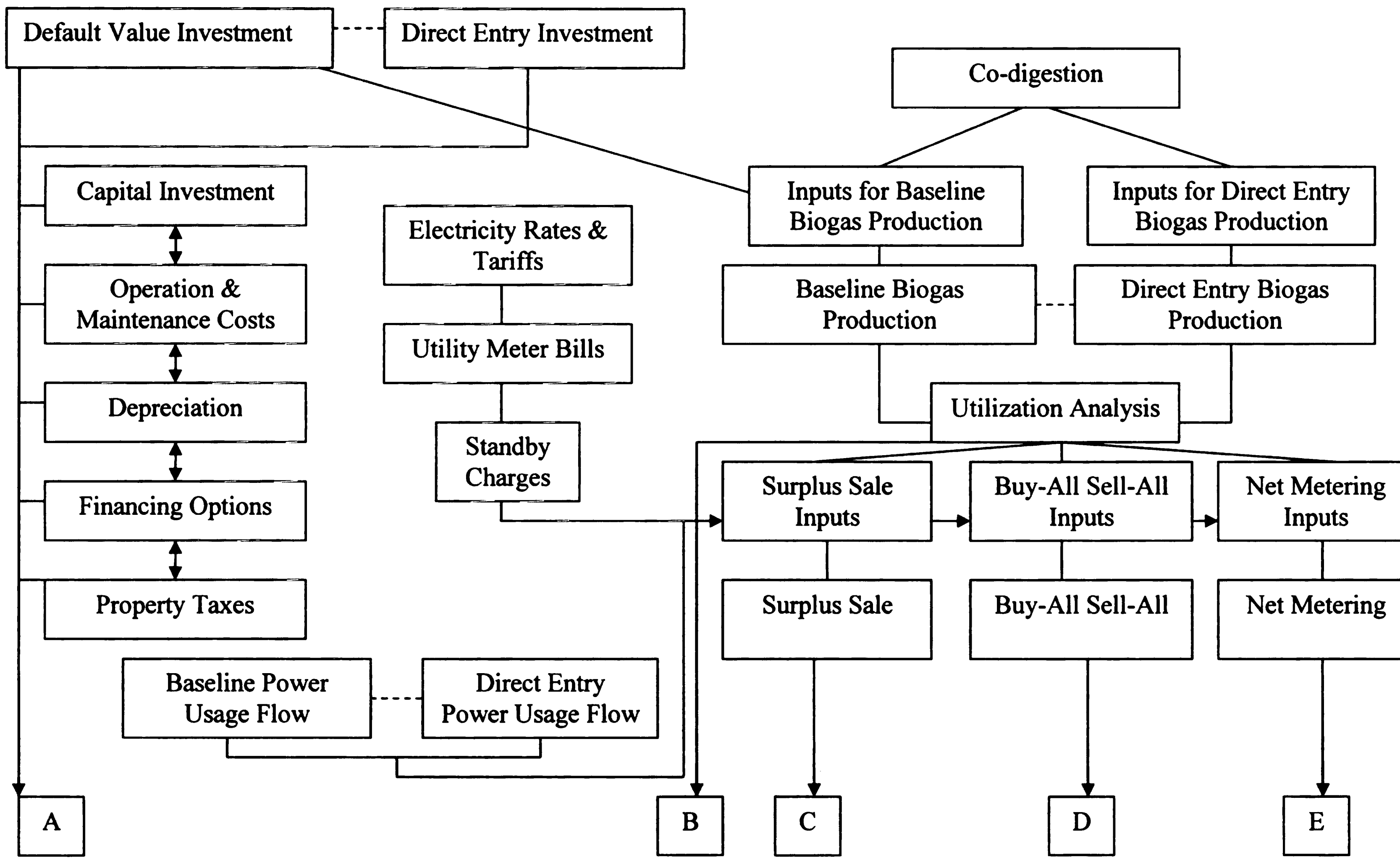
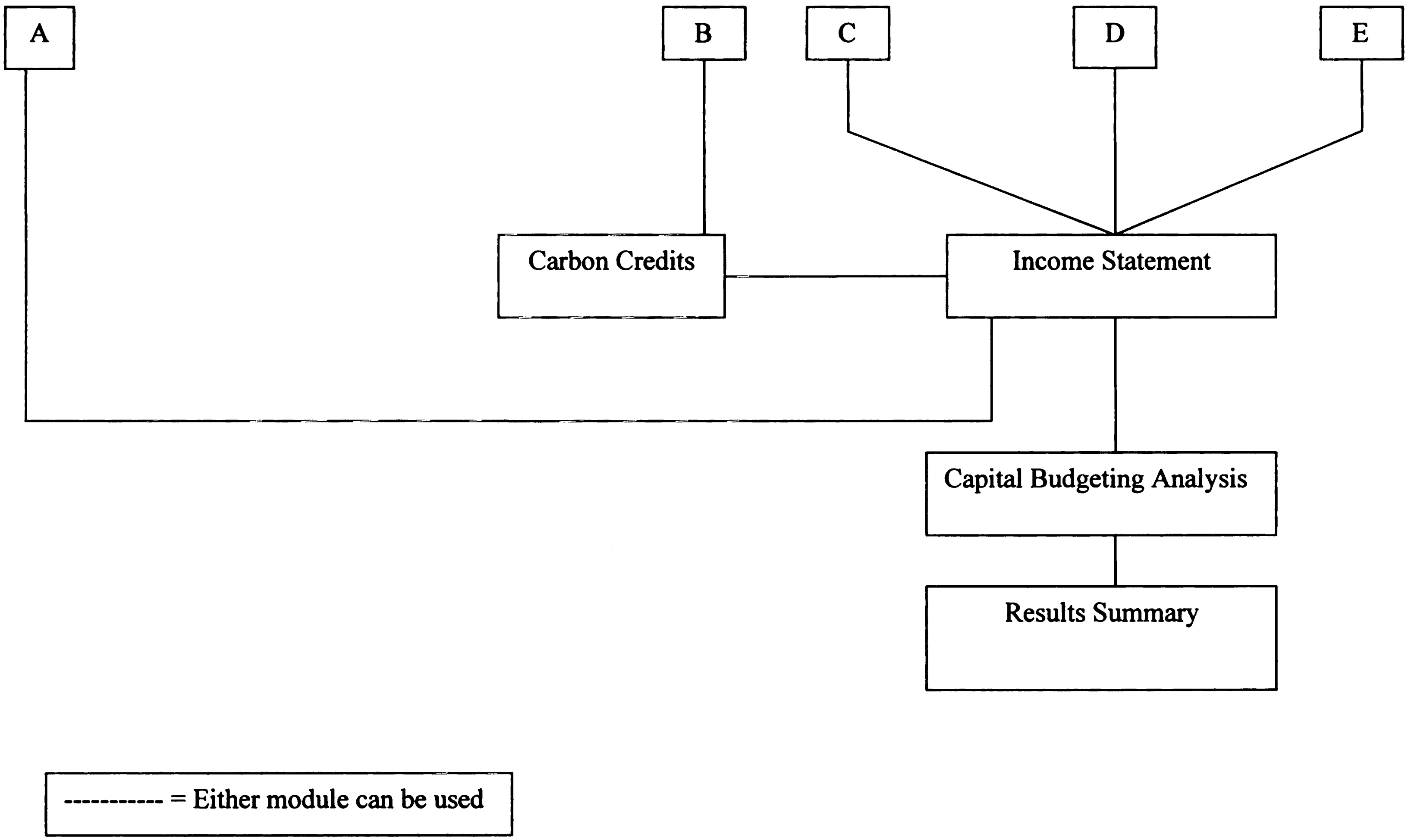


Figure 3. Model Layout (Continued)



3.1 Default Value Investment

The model has the option to utilize either a default value investment or directly entered investment information based upon the user's own information. The flexibility allows the user to provide decision support in the absence of specific cost data.

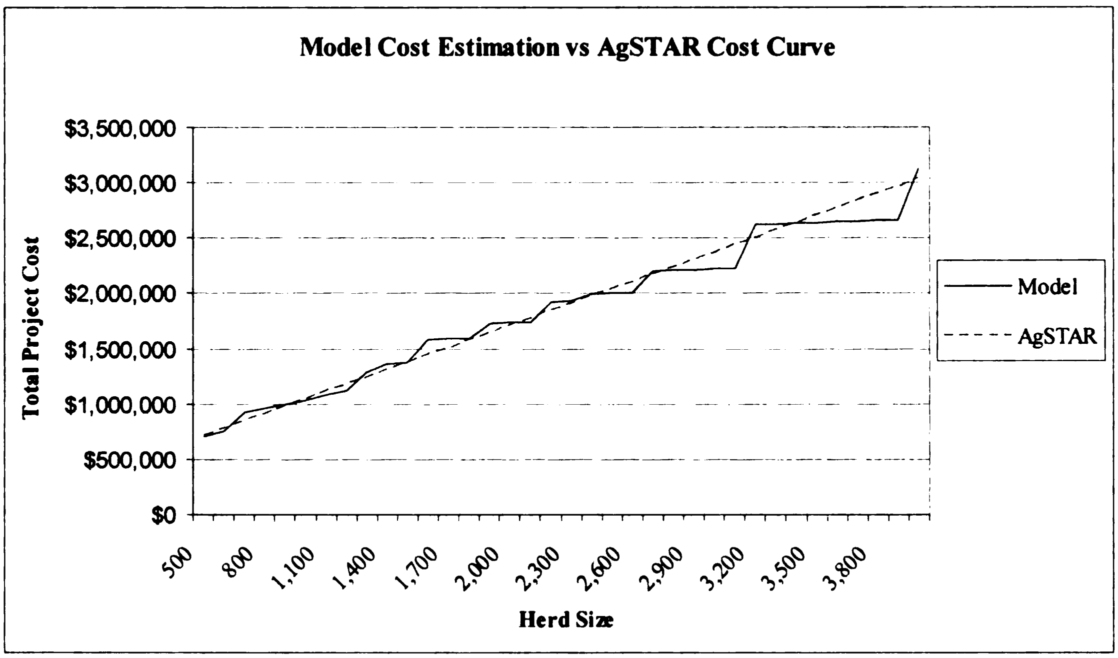
3.1.1 Capital Investment

Since digesters are often engineered to fit the individual needs of a particular farm, it is difficult to standardize the exact components included in each system. The task is further complicated by the fact that itemized budgets with each component (e.g., pumps, valves, mixers) separated out by cost are generally not publicly available. For example, the listed cost of a digester tank will generally aggregate the cost of the tank, roof, insulation, heating and related components together. The most valuable piece of data in cost determination, however, was the Michigan case farm budget which separated each component out by quantity and price. In order to design a default value investment module, component line items were estimated as either a percentage of total costs or sized based upon related elements of the digester system.

The total project costs formulated in the model were then benchmarked against complete mix digester cost curves created by the EPA AgSTAR program (U.S. EPA, 2009). AgSTAR analyzed AD system cost data for 10 complete mix digesters on dairy farms for which itemized cost estimates were available. Using SAS 9.1, regression analyses were performed for the complete mix digester costs versus the number of dairy cows. Included in the cost of each system was the cost of the digester, the engine-generator set, engineering design and installation. The analyzed systems did not include those designed for co-digestion and were based on quotes for systems in 2005-2008.

In order to validate the default value investment module, the model was then run for herd sizes ranging from 500 to 4,000 cows and compared to the AgSTAR cost curves (Figure 4).

Figure 4. Model Cost Estimation Compared with AgSTAR Cost Curve



When predicting the cost of the digester, the total solids content, hydraulic retention time (HRT) and amount of solids lost in collection are important in calculating the size of the tank and biogas production. For the model verification (Figure 4), the follow assumptions were made: scrape collected free stall barns, manure removed 3 times a day, Holstein cows (1,400 lbs.), parlor water added, a total solids (TS) content of 8%, a HRT of 20 days and a modest amount straw bedding.

3.1.2 Design Study and Engineering

This is not a capital cost, but was included in a majority of case budgets examined. Engineering and design fees were assumed to be to be 8% of the total capital costs (State of Louisiana, 2007).

3.1.3 Excavation

Excavation was estimated to be 4% of total capital costs and was taken from the case farm budget.

3.1.4 Tanks

The cost of tanks represents a significant portion of the investment and must be sized according to system parameters, as covered in sections 3.2.3A through 3.2.3 C. The post digestion storage, equalization tanks, roofs and insulation are sized and priced based upon the values determined for the digester tanks and are included in sections 3.2.3D through 3.2.3G.

3.1.4A Desired Tank Volume (Digester)

The desired tank volume (DTV) in gallons was estimated based upon the average daily flow rate (gallons per day) and the hydraulic retention time (HRT). An additional volume of 10% was then added for freeboard to arrive at the desired tank volume. Freeboard space is necessary to provide room for extra influent and gas storage in the case of a manure pump malfunction or engine-generator downtime. Equation 1 is the calculation for DTV.

$$DTV = (V_{AD} \times HRT) \times (1 + FB) \qquad \text{(Equation 1)}$$

DTV : Desired tank volume of the digester tank (gallons)
V_{AD} : Average daily flow rate (gallons/day)
HRT : Hydraulic retention time (days)
FB : Freeboard space

For EF[6]: 658,900 gallons = [29,950 gpd x 20 days] x (1.10)

3.1.4B Tank Quantity (Digester)

In order to determine the quantity of tanks needed, the assumption was made that 870,000 gallons would be the cut off point at which two digester tanks would be needed. This volume was selected based on an examination of all operational complete mix digesters listed on the EPA AgSTAR digester database (U.S. EPAb, 2009). For dairy farms utilizing more than one tank, the average tank volume was found to be approximately 870,000 gallons. Therefore, if the desired tank volume is less than 870,000 gallons, the assumption is made that one tank is used (Table 1).

Table 1. Tank Quantity

Desired Tank Volume (gallons)	**Tank Quantity**
0 - 870,000	1
> 870,000	DTV / 870,000 gallons[7]

3.1.4C Tank Unit Cost

To determine the unit cost of each digester tank, a similar methodology was used. Corrections are made, however, if the desired tank volume is greater than 870,000

[6] EF refers to a 1,000 cow example farm used to demonstrate the use of the model.
[7] Quantity rounded to the nearest whole number

gallons, but less than 1,000,000 gallons. For this specific interval, two 500,000 gallon tanks were utilized to avoid unnecessary capacity. Similarly, if the desired tank volume is greater than 1,000,000 gallons, but less than 1,400,000 gallons, then two 700,000 gallon tanks were used. The volume of the tank multiplied by a cost per gallon of $.20 becomes the unit cost (Equation 2). The tank quantity multiplied by the unit cost is the total digester tank cost (Equation 3). The value of $.20 was obtained from the case farm budget. Table 2 shows the determination of the Total Tank Volume.

Table 2. Total Tank Volume

DTV(gallons)	Selected Tank Size (gallons)	Tank Quantity	Total Tank Volume (gallons)
0 - 870,000	DTV	1	DTV
870,001 - 1,000,000	500,000	2	1,000,000
1,000,001 - 1,400,000	700,000	2	1,400,000
1,400,001 - 2,100,000	700,000	3	2,100,000
> 2,100,000	870,000	DTV / 870,000 gallons	870,000 x Tank Quantity

Unit Cost = Total Tank Volume (gallons) x Cost per Gallon (Equation 2)

For EF: $131,780 = 658,900 gallons x $0.20 per gallon

Total Digester Tank Cost = Tank Quantity x Unit Cost (Equation 3)

For EF: $131,780 = 1 Tank x $131,780

<u>*3.1.4D Tanks-(Post Storage)*</u>

Post digestion storage was obtained by first calculating the post storage tank volume from the case farm and comparing it to the volume of the digester tanks. The post digestion storage volume was found to be 20% of the digester tank volume for the case farm. This size relationship was then used to estimate the post digestion storage volume for all digester sizes in the model. The storage volume was then multiplied by a cost per gallon of \$.30 which was also taken from the case farm budget (Equation 4).

$$C_{Storage} = (DTV \times .20) \times C_{PG} \qquad \text{(Equation 4)}$$

$C_{Storage}$: Cost of post-storage tanks
C_{PG} : Cost per gallon for post storage tanks (\$/gallon)

For EF: \$39,534 = (658,900 gallons x .20) x \$0.30

3.1.4E Tanks-(Equalization)

Two equalization tanks are used to stabilize the inflow and outflow of manure and are assumed to be a fixed cost of \$8,000 per tank. This value was obtained from the case farm budget.

3.1.4F Roofs-(Digester)

The number of roofs needed is a function of the number of digester tanks and is assumed to be 60% of the cost of the digester tank. This value was obtained from the case farm budget.

3.1.4G Insulation

The number of units of insulation needed is a function of the number of digester tanks and is assumed to be 17% of the cost of the digester tank. This value was obtained from the case farm budget.

3.1.5 Boiler

To estimate the cost of the boiler, the size needed was determined by the total heat input required for the coldest average ambient temperature of the year (Perssen et al., 1979). The heat input required is a function of the heat loss through the digester and varies depending on the dimensions of the digester and the insulation material used. Two different size boilers were priced and the model was programmed to select the correct size based on the rated heat capacity (Btu/hr) of each boiler. The price of $90,000 was obtained from the case farm budget and the $45,000 was an estimate based on a boiler capacity need half the size of the case farm (Table 3).

Table 3. Boiler Size Ranges

Boiler Size Ranges	**Cost**
Boiler Size (300 MMBtu/hr to 2,000 MMBtu/hr)	$45,000
Boiler Size (2,001 MMBtu/hr to 5,000 MMBtu/hr)	$90,000

3.1.6 Heating

Heating refers to the tubes within the floors and walls of the digester tanks which circulate water. This water is warmed by waste heat recovered from the engine-generator and helps raise the influent temperature to the (95°-105°F) necessary for optimal mesophilic digestion. The number of units of heating was assumed to be a function of the number of digester tanks and a value of 5.5% of the cost of the digester tank was taken from the case farm budget.

3.1.7 Plumbing, Valves, Mixing and other Miscellaneous Components

The cost of plumbing, valves, mixing units and miscellaneous items were combined and were assumed to be 14% of total capital costs. This value was obtained from the case farm budget.

3.1.8 Water-to-Manure Heat Exchangers

Water-to-manure heat exchangers capture heat from the exhaust of the engine-generator and were assumed to be 4.5% of the total capital costs. This percentage was taken from the case farm budget. For the purposes of this study, a water-to-manure heat exchanger was not considered a piece of equipment to be included with all complete mix digesters. The module was programmed to include this piece of equipment, however, if additional heating ability is needed in addition to a boiler.

3.1.9 Instrumentation

Instrumentation refers to the cost of the computer equipment and flow meters to monitor the system and record the necessary information to receive carbon credits. This cost is assumed to be a fixed $28,000 and will not vary with herd size. This value was taken from the case farm budget.

3.1.10 Contingency

Contingency refers to funds set aside for unexpected budget overspends and increases in construction costs and were assumed to be 5% of total capital costs.

3.1.11 Engine-Generator

The cost of the generator was a function of the average yearly electricity output in kWh. A range of generator sizes was established based on case farm data and other published case studies (Table 4). When the average yearly electricity output falls between a particular engine-generator size range, the model selects the average cost associated with the corresponding generator.

Table 4. Engine-Generator Costs

Engine-Generator Size Range	Average Cost
701 kW to 900 kW	$400,000
501 kW to 700 kW	$350,000
301 kW to 500 kW	$300,000
201 kW to 300 kW	$250,000
121 kW to 200 kW	$200,000
50 kW to 120 kW	$150,000

3.1.12 Building

The cost of the building was assumed to be a function of the generator size and was estimated at 10% of the cost of the generator. The 10% was obtained from an actual itemized budget from a project developer.

3.1.13 Switchgear and Additional Engine Components

The switchgear and additional engine components were assumed to be a function of the generator size and were estimated at 70% of the generator cost. The additional engine components also include items such as heat exchangers which capture heat from the exhaust of the engine-generator. The 70% was based upon an actual itemized component list from a project developer (Equation 5). .

$$C_{SC} = C_{E-Generator} \times 0.70 \qquad \text{(Equation 5)}$$

C_{SC} : Cost of switchgear and components

$C_{E-Generator}$: Cost of the engine-generator

For EF: $140,000 = $200,000 x 0.70

3.1.14 Interconnection

The process of interconnection involves connecting an electricity producing generator to the grid. The cost can vary greatly depending on the location of the farm and the size of the generator (U.S. EPAa, 2009). The EPA AgSTAR program has estimated this cost to be 7.9% of the total project capital costs on average. This percentage is also used in the model.

3.1.15 Salvage Value

To determine the salvage value of the digester, the user must enter the value on each component that will remain at the end of the project period as a percentage of the purchase price. With both the direct-entry and the default value investment modules, the salvage value of the initial investment system components were not determined by the resulting book value under the Modified Accelerated Cost Recovery System (MACRS). In this study, the engine-generator was assumed to be worth 10% of the purchase price and the digester tanks (heat, insulation, roofing, concrete) were valued at 2%.

If the direct-entry investment module is being used, however, the book value (MACRS) of any repair and replacement parts purchased after the initial investment (year zero) are included in the salvage value. In this module, the total salvage value then consists of the percentage of value on each component from the initial investment combined with the book value of the repair and replacement parts remaining at the end of the project period. The direct-entry of repair and replacement costs is explained in detail in Section 3.3 which describes the operation and maintenance costs module.

3.2 Operation and Maintenance Costs

Operation and maintenance (O&M) costs were determined in the model by either directly entering specific values or using the default value investment module. The default value module calculates costs as a percentage of total capital costs obtained from the published literature. The values used in case farm examples are from the default value investment module since actual O&M data was not available.

3.2.1 Digester

When the user is analyzing an already existing system, specific data may be entered in the model. The costs are separated apart between the digester and the engine-generator unit.

For both the digester and generator maintenance, the labor costs were calculated as follows in Equation 6.

$$L_{YC} = L_{Hr} \times L_R \times 52\,weeks \qquad \text{(Equation 6)}$$

L_{YC} : Yearly labor costs ($)
L_{Hr}: Total hours to service and operate per week (hrs)
L_R : Rate of pay per hour ($/hr)

For EF: $3,276 = 3.5 hours x $18/hour x 52 weeks

For repairs and replacements, the costs were estimated. The sum of the annual costs for the first 5 years were determined and weighted for the flow of expenditures (Table 5). Expenditures in years four and five were weighted progressively higher. After year five, the costs increased at a rate of 3%. This approach was taken from the American Society of Agricultural and Biological Engineers (ASABE) in which downtime and reliability are calculated as a logarithmic cost function increasing with accumulated use and age.

Table 5. Direct-Entry Operation and Maintenance Costs

Cost for First 5 Years:	$150,000				
Rate Increase After Year 5:	3%				
Year	**1**	**2**	**3**	**4**	**5**
Cost Weight Factor:	10%	15%	20%	25%	30%
Repair and Replacement Cost:	$15,000	$22,500	$30,000	$37,500	$45,000

In addition to estimated costs, the model has the flexibility for the user to enter specific repair data for large purchases. Assets that are likely to need replacement or overhaul such as pumps and valves, mixing units, roofs and instrumentation are preprogrammed into the model. The model selects the higher value between the repair and replacement costs baseline estimation and the specific repair/replacement costs directly entered by the user. In the module, this is referred to the "adjusted digester repair and replacement cost." Since the baseline costs are estimated based on the amount spent for the first five years, they do not completely capture the cost fluctuations associated with large repairs/replacements occurring later on in the project period (e.g., year 10). In some cases, they may exceed the originally estimated amount. By selecting the higher value of the two, the model is not only accounting for the steady growth of O&M costs over time, but also incorporating the significant cost increases associated with large overhauls and major repairs in a given year.

Table 6. O&M Costs with Late Project Period Repair and Replacement

Year	**6**	**7**	**8**	**9**	**10**
Repair and Replacement Costs:	$46,350	$47,741	$49,173	$50,648	$52,167
Adj. Repair and Replacement Costs:	$46,350	$47,741	**$79,000**	$50,648	**$100,000**

The adjusted cost of $79,000 in year 8 is for roof repairs and the $100,000 in year 10 are for repairing pumps and valves. In both cases, these values exceed the amount originally estimated from the first five years of costs (Table 6).

These repair and replacement costs may be so costly that they exceed the available net working capital and need to be externally financed. In this case, a loan amortization schedule is also calculated in the financing module. In addition, if the purchase includes a depreciable asset, then the Modified Accelerated Cost Recovery System (MACRS) is applied according to the proper project life outlined in the IRS Publication 946.

3.2.2 Engine-Generator

Labor costs were calculated the same as with the digester. The cost of oil, however, is specific to the engine-generator and was calculated using the following equation.

$$O_{YC} = O_{Gallons} \times O_N \times O_{C/G} \qquad \text{(Equation 7)}$$

O_{YC} : Yearly engine generator oil costs ($)

$O_{Gallons}$: Oil required (gallons)

$O_{C/G}$: Cost per gallon ($/gallon)
O_N: Number of times oil is changed (times/yr)

For EF: $462 = 22 gallons x 7 times/yr x $3 per gallon

The frequency of oil changes can be directly entered by the user to account for varying concentrations of hydrogen sulfide in the biogas.

With repairs and replacements, the costs were estimated the same as with the digester. The sum of the annual costs for the first 5 years is determined and weighted for the flow of expenditures. After year 5, the costs were increased at 3% each year until the end of the project period. Incidental repair, replacement and overhaul costs can also be directly entered and are depreciated in the same manner as with the digester. If the user is analyzing a system in the absence of specific cost information, the O&M costs for both the digester and engine-generator can also be calculated using a percentage of total capital costs. Based upon estimates from the literature, this percentage was estimated to be between 3% and 7% (Beddoes et al., 2007; Bracmort, 2008). Due to this wide variability, an average value of 5% was spread out over the first five years and weighted progressively higher in years four and five (Table 7).

Table 7. Cost Weight Factor for O&M Costs Based Upon Percentage of Total Capital Costs

Year	1	2	3	4	5
Cost Weight Factor:	45%	55%	65%	80%	100%

The method of weighting the percentage of costs for the first five years was to account for the fact that digester and engine generator repair costs are likely to be minimal in the first several years of operation. After year five, however, the costs are increased at a rate of 3% until the end of the project period. By year 15, the O&M costs reach nearly seven percent of total capital costs which captures a balance between the range of values found in the literature. A steady growth of the O&M cost percentage will also help account for the large repair and replacement costs of the digester and engine-generator as they age. The total O&M costs for years 1 through 5 are calculated for the 1,000 cow example digester in Table 8.

Table 8. Operation and Maintenance Costs as a Percentage of Total Capital Costs

Year	1	2	3	4	5
% of Total Capital Costs:	2.25%	2.75%	3.25%	4.00%	5.00%
Total O&M Cost:	$18,700	$22,855	$27,011	$33,244	$41,555

3.3 Depreciation

The depreciation schedule is calculated using the (MACRS) 150% Declining Balance Method (Half-Year Convention). The recovery periods used for digester components were assumed to be either 15 years (single purpose livestock structure), 20 years (farm building) or 7 years (Farm Machinery and Equipment). The corresponding depreciation schedules were taken from the IRS Publication 946. The IRS Section 179 direct expensing option, however, was not considered in this model.

3.4 Property Taxes

In Michigan, on-farm anaerobic digester facilities (including the engine-generator) can be exempt from real and personal property taxes. In order to be eligible for the exemption, methane digester equipment must be certified by the Michigan Department of Agriculture (MDA) and the farm must be verified as compliant under the Michigan Agriculture Environmental Assurance Program (MAEAP). In addition, the facility owner must allow "access for not more than 2 universities to collect information regarding the effectiveness of the methane digester and the methane digester electric generating system in generating electricity and processing animal waste and production area waste" (DSIRE, 2009).

Currently, the Michigan Department of Treasury (MDT) has not dealt with the issue of how to properly value an anaerobic digester system for property tax purposes.[8] The assumption was made that the six operating digesters in the state must be taking advantage of the tax exemption. Since little information was available in this area, certain assumptions regarding the taxable project cost and fair market value of a digester were used. For example, all fixed structures were considered to be real property (taxable) and the value of 25% (fair market value as percent of total taxable project cost) was a "best guess" estimation. Since the MDT has indicated that no farms are currently paying property taxes on their digester systems, none of the analyses in this study include this expense.

$FMV = (P_{FMV} \times TC)$ *For EF: \$207,774 = (0.25 x \$831,097)*   (Equation 8)

$AV = (FMV \times P_{AV})$ *For EF: \$103,887 = (\$207,774 x 0.50)*   (Equation 9)

$PT = (AV \times TR)$ *For EF: \$3,117 = (\$103,887 x 0.03)*   (Equation 10)

TC : Total taxable project cost
P_{FMV} : Fair market value as percentage of total taxable project cost
P_{AV} : Assessed value as a percentage of fair market value
AV : Assessed value
FMV : Fair market value
PT : Property tax
TR : Tax rate

[8] Conversations with Michigan Department of Treasury

3.5 Biogas Production

Biogas production is estimated on a month to month basis over a period of one year. This allows aspects of seasonality (e.g., heat loss, manure freezing) to be accounted for which gives a more accurate view of digester performance. The biogas production modules of the model consist of three main elements: influent flow, digester heating and biogas and electricity production. The model is also set up to allow for the use of baseline or directly entered values when calculating monthly biogas production. For situations where a digester is not installed or daily influent values are unknown, biogas production can be calculated utilizing baseline values. Alternatively, if a pre-existing system is being evaluated, the user can enter more site specific data. In addition, hypothetical or existing situations with the co-digestion of additional feedstocks can also be modeled on a monthly basis.

3.5.1 Influent Flow

Influent flow is defined as the amount of material (e.g., water, manure, food processing water) which enters the digester per period. It is often measured by the daily flow rate and has implications on digester sizing, heating needs and biogas production.

3.5.1A Manure

In order to calculate the amount of manure influent entering the digester on a monthly basis, the following steps (Equations 11-14) are used based upon the daily flow rate. This rate includes the manure and any added dilution water from the milking parlor or other sources entering the digester.

Step (1)

$$Q_D = Q_{C/D} \times H \qquad \text{(Equation 11)}$$

Q_D: Daily flow rate (gallons per day)
$Q_{C/D}$: Flow rate per cow/day (gallons) [9]
H: Herd size (lactating and dry)

For EF: 29,950 gpd = 29.95 gallons x 1,000 lactating cows

Step (2)

$$V_D = Q_D \times LG \qquad \text{(Equation 12)}$$

V_D: Daily volume (ft^3/day)
LG: Liquid gallons per ft^3

For EF: 4,004 ft^3/day = 29,950 gpd x 0.133680556 gallons per ft3

Step (3)

$$M_D = V_D \times MD \qquad \text{(Equation 13)}$$

M_D: Daily mass (lb/d)
MD: Manure density (lb/ft^3) [10]

For EF: 249,937 lb/d = 4,004 ft3/day x 62.4

Step (4)

$$DM_T = [H_{LC} \times DM_{LC/D}] + [H_{DC} \times DM_{DC/D}] \qquad \text{(Equation 14)}$$

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[9] The most common values are 10 to 30 gallons of fresh water per milk cow (Burke, 2001).
[10] Manure Density= 62.4, (ASAE, 2005)

DM_T : Total dry matter (lb/d)
H_{LC} : Number of lactating cows
$DM_{LC/D}$: Dry matter per lactating cow/day
H_{DC} : Number of dry cows
$DM_{DC/D}$: Dry matter per dry cow/day

For EF: 20,000 lb/day = {1,000 Lactating Cows x 20 lb/day/cow} + {0[11] Dry Cows x 11 lb/day/cow}

The amount of manure per animal varies by animal type and production grouping. For the 1,000 cow example, the assumption is that all dry cows are kept in a separate barn and do not contribute manure to the digester. Table 9 contains a listing of manure characteristics from the American Society for Biological Engineers (ASAE, 2005). In addition to the animal manure produced, dry matter also includes organic animal bedding incorporated in the influent stream.

Table 9. Manure Characteristics from the American Society for Biological Engineers

Animal Type and Production Grouping	Total Solids (Dry Matter) (lbs/day/cow)
Beef-Cow (Confinement)	15
Beef-Growing Calf (Confinement)	6
Dairy-Lactating Cow	20
Dairy-Dry Cow	11
Swine-Gestating Sow (440 lb)	1.1
Swine-Lactating Sow (423 lb)	2.5

Once the daily dry matter per period has been determined, the percent of total solids (TS) is calculated by dividing the dry matter by the daily mass (lb/d) (Equation 15). The

[11] The assumption is made that dry cows are kept in a separate barn and are not contributing manure to the digester.

percentage of total solids concentration is important to monitor since it affects the heating needs of the digester and the type of digester design which is selected. It is not a constant due to water spill, humidity and the type of manure handling (Gebremedhin, 2006). In contrast to the dry matter which consists of only solid material, daily mass includes solids as well as added dilution water from the milking parlor or other sources entering the digester.

$$TS_C = DM_T / M_D \qquad \text{(Equation 15)}$$

TS_C : Total solids concentration (%)
DM_T : Total dry matter (lb/d)
M_D : Daily mass (lb/d)

For CF: 8% = 20,000 lb/d / 249,937 lb/d

From the amount of collectable total solids (dry matter), the actual volatile solids content is calculated using baseline values from both the dry and lactating dairy cows. The volatile solids (VS) content determines the amount of degradable solids which can produce biogas from manure or any other feedstock suitable for anaerobic digestion (Equation 16). Lost solids as a result of biodegradation during the pretreatment process are also accounted for in the equation, since it can have a significant impact on biogas production (Equation 17).

$$M_{VS} = DM_T \times VS_C \qquad \text{(Equation 16)}$$

M_{VS} : Volatile solids mass (lb/d)
VS_C : Volatile solids concentration (%)[12]

[12] VS (%) = 85%, (Steffen et al., 1998)

For CF: 17,000 lb/d = 20,000 lb/d x 0.85

$$M_{VS(i)} = M_{VS(i)} - (1 - L_{VS}) \quad \text{(Equation 17)}$$

$M_{VS(i)}$: Volatile solids mass (lb/period i)
L_{VS}: Volatile solids loss (%)
i: Period of time (e.g. hour, day, month)

For CF: 17,000 lb/d = [17,000 lb/d – (1 - 0%[13])]

3.6 Utilization Analysis

To calculate the biogas yield from either manure or additional feedstocks, Equation 18 is used. The result is multiplied by the biogas methane concentration to obtain the energy potential (Equation 19). The biogas production levels were assumed to be constant for the 15 year project period.

$$Y_{B(i)} = M_{VS(i)} \times B_{VS}. \quad \text{(Equation 18)}$$

$Y_{B(i)}$: Biogas yield (ft^3/ period i)
$M_{VS(i)}$: Volatile solids entering the digester (lb/period i)
B_{VS}: Biogas produced per (ft^3/lb of VS destroyed)

For EF: 73,100 ft^3/d = 17,000 lb/d x 4.3 ft^3/lb[14]

$$E_{AD(i)} = Y_{B(i)} \times M_C \quad \text{(Equation 19)}$$

E_{AD}: Energy produced by the system (Btu/period i)

[13] The amount of solids lost depends on the system and a value of 0% was chosen in this example.
[14] This value is an average taken from various literature sources (Steffen et al., 1998; Bracmort et al., 2008).

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M_C : Methane concentration (%)

For EF: 43,860 =73,100 ft³/d x 60%[15]

3.6.1 Digester Heating

In order to account for the amount of heat leaving the digester, the model was programmed to either calculate heat loss values based upon the specific dimensions of the digester tank and construction material or assume heat loss as a percentage of energy potential. Regardless of the method, the first step is to calculate the amount of heat needed to warm the influent (manure and feedstock) to the target temperature. For complete mix digesters operating in the mesophillic range, this is generally between 95°F and 105°F (Lusk, 1998). The same formula is applied to all influent entering the digester (including additional feedstocks) (Equation 20).

$$Q_i = mC_p(T_o - T_i) \qquad \text{(Equation 20)}$$

Q_i : Energy needed to heat the digester to optimal temperature (Btu for period i)
m : Mass flow rate (lbs/period i)
T_o : Effluent temperature which is equal to the digester temperature (°F)
T_i : Influent temperature for period i (°F)[16]
C_p : Specific heat of feedstock (assumed to be equal to that of water, 1 Btu/lb)
i : Period of analysis (e.g. January)

For EF: 759,183 Btu/hr = 10,414 lb/hr x 1 Btu/lb x (95°F – 22.1°F[17]

[15] 55-65% (U.S. EPA, 2002)
[16] Assumed to be ambient temperature
[17] Average ambient temperature for the month of January in central Michigan (U.S. EPA, Undated)

When using specific digester dimensions to calculate heat loss through the floor, walls and roof, Equation 21 was used (Persson et al., 1979). The thermal conductivity coefficient varies depending on the construction material. Increased insulation will decrease this value. When calculating surface area, a distinction is made between the portion of the wall buried in the soil and that which is exposed to ambient temperatures. The soil can provide some insulation in the winter months with temperatures assumed to be 55°F year-round at a depth of six feet (NREL, 2009). The depth of digester (if buried at all) will be input by the user. Ambient temperatures from the FarmWare 3.1 simulator were used which obtains its data from the National Climate Data Center.

$$Q_H = \sum_{j=1}^{n} U_j A_j (t_i - t_o) \qquad \text{(Equation 21)}$$

Q_H : Digester Heat Loss (Btu/hr)
U : Thermal conductivity coefficient
A : Surface Area (ft^2)
t_i : Inside temperature (°F)
t_o : Outside temperature (°F)
i : Period of analysis
j : Type of surface being insulated

If digester heat loss is not being calculated based upon specific construction materials and surface area dimensions, it can also be determined based upon a percentage of the digester energy potential (Btu/hr) (Equation 22). A value of 5% was taken from the literature (Liu et al., 2008). Since specific digester tank data from a 1,000 cow dairy was not available, the analysis in this study uses the 5% estimate to determine heat loss.

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$Q_H = E_{AD}$ *x 5%* (Equation 22)

Q_H : Digester Heat Loss (Btu/hr)
E_{AD} : Energy produced by the system (Btu/hr)

For EF: 91,375 Btu/hr = 1,827,500 Btu/hr x 5%

The minimal energy needed for static warmth ($E_{AD, Min}$,Btu/hr) then becomes the heat needed to warm the influent to the target temperature plus digester heat loss (Btu/hr) (Equation 23).

$$E_{AD, Min} = mC_P(T_o - T_i) + Q \times E_{AD}$$ (Equation 23)

$E_{AD, Min}$: Minimum heat needed for static warmth (Btu/hr)
E_{AD} : Energy produced by the system (Btu/hr)
Q : Heat loss (%)

For EF: 850,558 Btu/hr = [10,414 lbs/hr x 1 Btu/lb x (95°F – 22.1°F)] + (5% x 1,827,500 Btu/hr)

The energy required from the boiler is the minimum energy required for static warmth less the energy captured from waste heat (Equation 24). Waste heat comes from both the exhaust of the engine-generator and the water-to-manure heat exchanger (if one is used). Waste heat captured from engine-generator is determined by multiplying the heat recovery efficiency[18] of the heat exchangers by the energy potential (Btu/period) of the digester. The amount of heat recovered from the water-to-manure heat exchanger is based upon manufacturing specifications and must be input directly.

$$E_B = \left(E_{AD, Min} - W_{EG} - W_{Manure}\right) / B_{EF}$$ (Equation 24)

[18] The industry standard of 40% was assumed in the model

E_B : Energy required from boiler (Btu/hr)[19]

W_{EG} : Waste heat captured from exhaust off the engine-generator (Btu/hr)

W_{Manure} : Waste heat captured from the water-to-manure heat exchanger (Btu/hr)

B_{EF} : The efficiency of the boiler (%)

For EF: 299,302 Btu/hr = [850,558 Btu/hr – 611,116 Btu/hr - 0[20] Btu/hr]/80%

The net energy potential of the system is the energy produced by the digester reduced by the energy required to run the boiler (Equation 25).

$$E_{Net} = E_{AD} - E_B \qquad \text{(Equation 25)}$$

E_{Net} : Net energy potential of the system (Btu/hr)

For EF: 1,827,500 Btu/hr = 1,827,500 Btu/hr - 299,302 Btu/hr

3.6.2 Co-digestion

The amount of additional feedstock influent is accounted for in a separate module. The co-digestion module accounts for the specific characteristics of each feedstock and then combines them with the biogas production from the manure.

3.6.2A Feedstock Cost

The final cost of feedstock includes the cost of the feedstock itself, fuel, labor and disposal. Unless the amount of feedstock added is significant (e.g., 50% of total volume), the cost of disposal is not expected to be different than what is normally spent on the disposal of manure without added feedstock. The user may enter a disposal cost figure if

[19] Based upon the month of January

[20] This example does not include a water-to-manure heat exchanger.

it is considered appropriate. The transportation fuel cost is influenced by the distance traveled, speed, vehicle fuel efficiency and the cost of fuel. The transportation labor cost is influenced by the duration of the trip and the hourly pay rate of the worker as described in Equation 25.

$$C_T = T_D + T_L + T_F + (F_Q + C_U) \qquad \text{(Equation 25)}$$

F_Q : Feedstock quantity (tons)
C_U : Cost per unit ($)
T_F : Transportation fuel costs ($)
T_L : Transportation labor costs ($)
T_D : Transportation cost for disposal ($)
C_T : Total feedstock cost per truck load ($/load)

For EF: $129=$0+$61 +$33+ (7 tons x $5.00)

3.6.2B Feedstock Revenue

The cost of transportation is not considered in this equation, since the farm generally will not incur the delivery cost when tipping fees are involved. Tipping fees are a payment to the farm from an outside entity (e.g., restaurant, food processor) for the ability to dispose of their organic waste in the digester. The feedstock revenue is the amount of feedstock delivered to the farm multiplied by the revenue per unit (Equation 26). The disposal cost is considered at the discretion of the user and will depend on the amount of feedstock added.

$$R_T = (F_Q \times R_U) - T_D \qquad \text{(Equation 26)}$$

R_U : Revenue per unit ($)
R_T : Total feedstock revenue ($)

For EF: $400 = (10 tons x $40 per ton) - $0

3.6.2C Amount of Feedstock Entering the Digester per Day

It is important to determine the amount of feedstock entering the digester in order to accurately determine the energy potential and digester heating requirements. In addition, it is convenient in planning a digester to consider the amount of additional feedstock added when determining the digester tank size. The average percentage of feedstock added each day will depend on the management practices of the digester operator and it varies between systems. The model assumed that a constant percentage of each truck load was fed to the digester each day. In practice, however, this percentage will vary widely.

3.6.2D Feedstock Characteristics and Biogas Yield

Due to the variability among different feedstocks, the energy potential of each must be calculated separately. Some agro-industrial wastes may contain less than 1% total solids (TS), while others contain high TS contents of more than 20% (Steffen et al., 1998). There is also wide variability in the content of VS and resulting conversion to methane. Equations 27-30 show an example of adding 7 tons of ethanol syrup three times per month throughout the year[21].

$M_{DF(i)} = F_{AD(i)} \times TS_{CF}$ *For EF: 3,150 lb/d = 42,000 lb/d x 15%* (Eq. 27)

$VS_{F(i)} = M_{DF(i)} \times VS_{CF}$ *For EF: 2,698 lb/d = 3,150 lb/d x 85.66%* (Eq. 28)

$Y_{BF(i)} = VS_{F(i)} \times Y_{BF}$ *For EF: 40,474 ft³/d = 2,698 lb/d x 15 ft³/lb of VS* (Eq. 29)

[21] Values pertaining the characteristics of ethanol syrup taken from (Rosentrater et al., 2006).

$$E_{F(i)} = Y_{BF(i)} \times M_{CF} \qquad \textit{For EF: } 29{,}951\, ft^3/d = 40{,}474\, ft^3/d \times 74\% \qquad \text{(Eq. 30)}$$

$M_{DF(i)}$: Feedstock mass (lb/period i)

$F_{AD(i)}$: Feedstock added to the digester (lb/period i)

TS_{CF} : Total solids concentration in feedstock (%)

$VS_{F(i)}$: Volatile solids (lb/period i)

VS_{CF} : Volatile solids concentration in feedstock (%)

$Y_{BF(i)}$: Biogas Yield per period (ft^3/period)

Y_{BF} : Biogas Yield (ft^3/lb of VS_F destroyed)

$E_{F(i)}$: Energy produced from added feedstock (ft^3/period)

M_{CF} : Methane concentration of feedstock (%)

3.6.3 Energy Uses

The actual energy potential sent to the engine-generator must be net of any biogas that is used to offset the use of propane. Offsets achieved using waste heat from the engine generator (net of digester heating needs) will not have an effect on the actual energy potential. The user has the option whether to include these offsets and which energy source will be used (biogas or waste heat).

In addition, the actual energy potential (E_A) is adjusted for when the methane produced exceeds the capacity of the engine-generator (Equation 31). The excess methane is then sent to a flare where it is burned. In this circumstance, if E_A exceeds the rated capacity of the engine-generator, the model will use the rated capacity as the adjusted actual energy potential.

$$E_A = E_{Net} - E_P \qquad \text{(Equation 31)}$$

E_A: Actual energy potential net of all other uses (Btu/period)
E_{Net}: Energy potential net of digester heating requirements (Btu/period)
E_P: Energy potential from biogas used as a propane offset (Btu/period)

For EF: 1,827,500 Btu/hr = 1,827,500 Btu/hr – 0 Btu/hr[22]

3.6.3A Propane Offsets

The user has the option whether to include propane offsets as a potential energy use. The energy required to replace propane can come either from waste heat or from biogas net of any boiler use to warm the digester. Since farm heating needs are seasonal, the model also gives the option to select which months are included.

Assuming a value of 92,000 Btu's per gallon, the energy available from the digester is converted to a gallon equivalent in Equations 32-33. The examples provided are for the month of January.

$$P_P = E_{Net} / \text{Btu's per gallon} \qquad \text{(Equation 32)}$$

1.23 gallons/hr = 113,351 Btu/hr / 92,000 Btu/gallon

or

$$P_P = E_{waste} / \text{Btu's per gallon} \qquad \text{(Equation 33)}$$

0 gallons/hr = 0 Btu/hr / 92,000 Btu/gallon

P_P: Propane offset potential (gallons/period)
E_{Net}: Energy potential net of digester heating requirements (Btu/period)

[22] This example assumes no propane offsets.

E_{waste}: Energy potential from waste heat (Btu/period)

To estimate the on-farm propane use, 11 gallons per cow/year was assumed (Lazarus, 2003). This is based upon the heating needs of the milking parlor and cow holding area. The actual on-farm propane offset is either the on-farm need for the selected time period (based upon 11 gallons per cow/year) or the propane offset potential produced by the digester. For example, if the propane offset potential from the digester is less than the farm's need, the actual propane offset becomes the energy potential produced from the digester and vice versa. The example provided is for the month of January and assumes waste heat as the energy source (Equation 34).

$$P_{AP} = \min(E_P, P_{Farm}) \qquad \text{(Equation 34)}$$

P_{AP}: Actual propane offset (gallons/period)
P_{Farm}: On-farm propane need (gallons/period)
E_P: Energy potential available (per period) for propane offsets (either E_{Net} or E_{waste})

For EF: 0 gallons/month= min (0 gallons/month, 917 gallons/month)

It is important to note that excess waste heat may not always be available during the winter months when it is needed most. This is due to the fact that the majority of the waste heat will be used for digester heating requirements.

3.6.3B Electricity Generation

Electricity generation (E_G) is calculated by multiplying the actual energy potential by the recovery and engine efficiency of the generator (Equation 35). The generator is assumed to be an internal combustion engine. The E_G value is also adjusted for the parasitic energy load of the tank mixers.

$$E_G = [(E_A \times G_{RE} \times G_{EE}) \times (1 - P)] / 3{,}412\ Btu/kWh \qquad \text{(Equation 35)}$$

E_G: Electricity generation (kWh/hr)
E_A: Actual energy potential net of all other uses (Btu/period)
G_{RE}: Online time of the engine generator (%)
G_{EE}: Engine efficiency of the engine generator (%)
P: Parasitic energy requirement (% of E_G)

For EF: 138 kWh/hr = [(1,528,198 Btu/hr x 90% x 0.35) x (1-0.02)] / 3,412 Btu/kWh

The parasitic energy requirement (P) refers to the amount of energy needed to power the tank mixers. From case farm data, this value was calculated to be 2% and is used as a constant in the model.

To arrive at this value, Equation 36 was used:

$$P = [(M_{ER} \times M_N) \times M_{Hr}] / E_G \qquad \text{(Equation 36)}$$

M_{ER}: Energy requirement per mixer (kW)
M_N: Number of mixers
M_{Hr}: Number of hours run per day (hrs)

3.7 Electricity Purchase Agreements

Each sub-module has its own corresponding set of inputs (prices, profit retention, meters included and sales charges) which can be altered for scenario comparison purposes. Additionally, with all three agreements, the model is programmed for the user to select which electricity meters are to be included in the analysis.

3.7.1 Surplus Sale

Since a surplus sale agreement involves the offsetting of on-farm energy needs, a power usage index[23] is used which specifies the amount of electricity used per hour for each month. This is necessary because a farm can only offset the amount of energy they are using at any given moment. Once power usage flows are established, the amount of electricity that is available for sale to the utility can be determined. The example provided in Equation 37 is for 7 am in the month of January.

$$K_{UP} = U_P \times U_A \qquad \text{(Equation 37)}$$

U_A: Annual electricity usage (kWh)
U_P: Percentage of energy used per hour per month (%/hr/month)
K_{UP}: kWh used per period (kWh)

For EF: 5,125 kWh = 0.4545% x 833,288 kWh

If the electricity generated exceeds the farm's need for a particular hour, then electricity is sold back to the utility company. Likewise, if a farm is at a deficit for a given hour, the needed electricity must be purchased.

Under a surplus sale agreement, on-farm electricity offset by the system is valued at the commercial retail rate.[24] The commercial rate used in the model was obtained from utility bills at the Michigan case farm. The electricity pricing for the 15 year project period was then determined by creating an index from the DOE Energy Information

[23] The index was taken from a representative dairy farm different from the case farm used in the calibration of the default value investment module.
[24] The commercial rate is used as a constant for all three agreements for a given year.

Administration. In Equation 38, the kilowatt hours offset by the system are multiplied by the commercial rate and totaled for the month.

$$V_{offset} = \sum_{i=1}^{n} (KH_{offset(i)} \times E_{retail}) \qquad \text{(Equation 38)}$$

V_{offset} : Value of on-farm electricity offset (\$/kWh)
$KH_{offset(i)}$: Hourly kWh offset by the system (kWh)
E_{retail} : The commercial retail rate for electricity (\$/kWh)
i : Period of time (e.g., hour, month)

For EF: \$374 = 3,787 kWh x \$.0988 kWh

In contrast, any electricity that is sold back to the utility is valued at the 2009 average real-time Locational Marginal Price (LMP) of the particular utility's load node as determined by the Midwest Independent Transmission System Operator (MISO). These prices are forecasts used in planning activities involving Michigan's PA 295 and energy optimization. The hourly values are then totaled up to arrive at monthly and yearly electricity sales and savings.

$$V_{sold} = \sum_{i=1}^{n} (KH_{excess(i)} \times E_{LMP}) \qquad \text{(Equation 39)}$$

V_{sold} : Value of on-farm electricity sold (\$/kWh)
$KH_{excess(i)}$: Hourly kWh produced in excess of on-farm electricity need (kWh)
E_{LMP} : The average monthly real-time locational marginal price (LMP) (\$/kWh)

For EF: \$22 = 499 kWh x \$0.04392 kWh

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The electricity produced is also eligible to be sold for Renewable Energy Credits (RECs) and is separate from the surplus sale electricity purchase agreement. Equation 40 shows the total value of RECs earned for the month of January. One REC is worth 1,000 kWh.

$$V_{REC} = \sum_{i=1}^{n}[(KH_{G(i)} / 1{,}000kWh) \times P_{REC}] \qquad \text{(Equation 40)}$$

$\$2{,}725 = (102{,}864\ kWh / 1{,}000) \times \$26.50$[25]

V_{REC}: Value of a renewable energy credit ($)
$KH_{G(i)}$: Hourly kWh generated by the system (kWh)
P_{REC}: Price of a renewable energy credit ($/MW)

In addition to the revenues associated with electricity production, several selling expenses such as a monthly administrative expense and the cost of an additional phone line must be included. The administrative expense is valued at $0.0010 per kWh[26] of electricity sold and the phone line is assumed to be a monthly fixed rate of $30.[27] The phone line charge is variable, however, and can be much higher depending of the nameplate capacity of the engine-generator and rules of the utility company. A system access charge of $100 also applies with an engine-generator nameplate capacity over 100 kW.

3.7.2 Buy-All Sell-All

Under a buy-all sell-all agreement, no on-farm electricity use is offset by the system. The calculation of electricity sales is equal to the number of kWh's generated per month

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[25] $26.50 was obtained from the Michigan case farm
[26] (Consumers Energy, 2009)
[27] Estimate from Conversations with Consumers Energy

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multiplied by the average real-time LMP rate per kWh (Equation 41). The calculation is the same as under the surplus sale agreement.

$$V_{generated} = \sum_{i=1}^{n} (KH_{G(i)} \times E_{LMP})) \qquad \text{(Equation 41)}$$

$V_{generated}$ *: Value of electricity generated ($)*

For EF: $4,518 =102,864 kWh x $0.04392 kWh

The farm, however, must purchase all electricity needs from the utility company at the full commercial retail value.

The formulas regarding the sale of RECs are the same as under the surplus sale agreement. The selling expenses associated with the sale of energy (administrative charge, phone line charges) are also calculated the same way as under the surplus sale agreement. In addition, the farm must pay a system access charge of $100 per month to sell back to the utility.

3.7.3 Net Metering

Under a net metering agreement, the farm uses electricity produced by the digester to offset on-farm usage. Excess electricity is then credited to next month's bill. In order to determine the amount of energy credited and used to offset purchases, the same power usage flow index is used as under the surplus sale agreement (Equation 42). In contrast however, excess energy on an hourly basis is credited instead of sold and is valued at the

power supply component (see Section 12) of the customer's electricity bill (Equation 43).

$$V_{offset} = \sum_{i=1}^{n} (KH_{offset(i)} \times E_{retail}) \qquad \text{(Equation 42)}$$

V_{offset} : Value of on-farm electricity offset (\$/kWh)
$KH_{offset(i)}$: Hourly kWh offset by the system (kWh)
E_{retail} : The commercial retail rate for electricity (\$/kWh)
i : Period of time (e.g., hour, month)

For EF: \$374 = 3,787 kWh x \$.0988 kWh

$$V_{credit} = \sum_{i=1}^{n} (KH_{excess(i)} \times E_{PSC}) \qquad \text{(Equation 43)}$$

V_{credit} : Value of hourly electricity credit (\$)
$KH_{excess(i)}$: Hourly kWh's produced in excess of the on-farm electricity need
E_{PSC} : The power supply component of the customer's bill (\$/kWh)

For EF: \$251 = (3,787 kWh x \$0.06615 kWh[28])

All formulas regarding RECs, profit retention and selling expenses are the same as under the surplus sale agreement.

3.8 Utility Meter Bills

A key element of the model is the ability to examine the effect of various electricity agreements based upon actual utility bills provided by the farm. The rates and tariffs will vary depending on the utility company and will need to be entered at the beginning of the

[28] Value taken from utility bills at case farm

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analysis. For this study, the rates and tariffs used under a demand rate schedule typical for medium to large dairies are used in the model. The model estimates demand by using actual data from the Michigan case farm and scaling the values to the needs of the farm size analyzed.

Under a demand rate schedule, the farm is charged for their peak demand usage in addition to monthly kWh charges. The charge per kWh (e.g., $0.056), however, is considerably lower than the typical commercial rate (e.g., $0.098)[29]. If a farm can maintain low peak demand, they will end up actually paying less than the typical commercial rate depending on the meter. Due to the fact that farms often have multiple meters with varying levels of peak demand, however, the rate charged per meter will vary. In order to determine a single rate to use in the model, the rates charged for electricity usage were averaged together. To calculate electricity charges for the entire year, the user must enter the historical usage information included on the monthly bill.

3.9 Standby Charges

The specifics of standby service will vary depending on the utility company, but generally are composed of two parts, Power Supply and Delivery Standby Charges (see Section 2.9.1). The rates used in the research are taken from a large representative utility company in Michigan and should be considered as a close approximation of what the actual charges would be. Information regarding the specific charges can be located in the utility company's rates and tariffs book and are available from the Michigan Public Service Commission (MPSC) or the company's website.

[29] Michigan case farm utility bill

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3.9.1 Power Supply Standby Charges

Power supply standby charges fluctuate month to month reflecting the changing MISO costs from variations in electricity demand. In this model, the average monthly LMP was used in order to increase the flexibility of the model.[30] Equation 44 summarizes the power and delivery standby charges for one meter in the month of January.

$$SC_{PS(m)} = KH_{C(m)} \times E_{LMP(m)} \qquad \text{(Equation 44)}$$

$SC_{PS(m)}$: Monthly power supply standby charges (\$)

$KH_{C(m)}$: Monthly on-farm electricity consumption (kWh)

E_{LMP} : Monthly location marginal price for electricity

For EF: \$398 = 9,063 kWh x \$0.04392

3.9.2 Delivery Standby Charges

Similar to charges for power supply, delivery standby charges only apply to customers with engine-generator nameplate capacities greater than 100 kW, as in Equation 45. The following rates are taken from a Michigan utility company and are used in all analyses in this study.

$$SC_{D(m)} = (MSD_{(m)} \times C_{capacity}) + (KH_{C(m)} \times C_{distribution}) \qquad \text{(Equation 45)}$$

$SC_{D(m)}$: Delivery standby charges (\$)

$C_{capacity}$: Capacity charge per kw of max standby demand (\$/kW)

$MSD_{(m)}$: Maximum standby demand (kW)

$C_{distribution}$: Distribution charge per kWh of consumption (\$)

m : Month of the year

[30] (Consumers Energy, 2009)

For EF: \$65 = (27 kW x \$1.77) + (9,063 kWh x \$0.003009)

The total standby charges then become the sum of the power supply and distribution charges.

$$SC_{T(m)} = SC_{PS(m)} + SC_{D(m)} \qquad \text{(Equation 46)}$$

$SC_{T(m)}$: Total standby charges (power supply and distribution)

For EF: \$463 = \$398 + \$65

Where:

The Capacity Charge is a Michigan Public Service Commission(MPSC)-authorized charge applicable to most nonresidential customers which recovers system costs for transporting electricity from the transmission (high voltage) lines over the distribution (lower voltage) lines to the customer's premises. A value of \$1.77 was used in the analysis (Consumers Energy, 2009).

Maximum Standby Demand is the highest 15-minute kW demand created during the previous 11 months ("Historical Max" on the customer bill) minus the contracted demand created during the current month ("Max Demand" on the customer bill) (Equation 47). The max standby demand, however, cannot be less than 80% of the monthly max demand (kW). This prevents the farm from avoiding standby charges for a given month in which the historical maximum demand over the past 11 months is very close or equal to the maximum demand.

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$$MSD_{(m)} = MX_{hist(m)} - MX_{demand(m)} \qquad \text{(Equation 47)}$$

$MSD_{(m)}$: Maximum standby demand (kW)

$MX_{hist(m)}$: Historical maximum demand (kW)

$MX_{demand(m)}$: Maximum demand (kW)

The Distribution Charge is a MPSC-authorized charge based upon the electric energy (kWh) used by the customer. This charge allows the utility to recover costs for delivering electric energy from the transmission system to the customer's premises, including operating and maintenance expenses of the distribution plant. A value of $0.003009 per kWh was used in the analysis (Consumers Energy, 2009).

It is not always the case, however, that the customer must pay standby charges to receive service. Under a typical surplus sale agreement, if the generator installed has a nameplate capacity under 100 kW, then no standby charges are paid. Similarly, under the Michigan Net Metering Law, no standby charges are paid if the generator nameplate capacity is less than 150 kW. The model developed as part of this study is programmed to account for these differences and can be altered depending on the rules of the individual utility.

3.10 Carbon Credits

Once it has been determined that the digester system is eligible to receive carbon credits, there are two methods for calculating a methane emission baseline. The method yielding the lowest value is used for the issuing of credits.

3.10.1 Methane Combustion Method

Actual monitored amount of methane captured and destroyed by the project activity using existing CCX monitoring protocols and a Global Warming Potential (GWP) for methane of 21. The GWP for a particular greenhouse gas is defined as the ratio of heat trapped by one unit mass of the greenhouse gas to that of one unit mass of CO_2 over a specified time period.[31] The final amount of methane destroyed includes biogas that is either combusted in an electric generator or flare. The examples provided are for the month of January and are shown in Equation 48.

$$CH_{4(R)} = (B_{Generator} + B_{Flare}) \times CH_{4(Average)} \qquad \text{(Equation 48)}$$

$CH_{4(R)}$: Methane recovered (ft^3/year)
$B_{Generator}$: Biogas to the generator (ft^3/year)
B_{Flare}: Biogas to flare (ft^3/ year)
$CH_{4(Average)}$: Average monthly methane (%)

For EF: 15,426,108 (ft^3/yr) = [23,139,162 (ft^3/yr) + 2,571,018(ft^3/ yr)] x 60%

The monthly methane flows are then summed on a yearly basis and converted to metric tons per year (Mg/yr). Lastly, the methane combusted (Mg/yr) is converted to carbon credits through a conversion factor established by CCX (Equations 49-50).

$$CH_{4(C)} = CH_{4(R)} \text{ x [16 (molecular weight of } CH_4)] \text{ x [1Mg/}10^6 \text{ g] x [1mol/24.04L @STP] x [28.32 L/1cf]} \qquad \text{(Equation 49)}$$

$CH_{4(C)}$: Methane combusted (Mg/yr)

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For EF: 291(Mg/yr) = [15,426,108 (ft^3/yr)] x [16 (molecular weight of CH_4)] x [1Mg/10^6 g] x [1mol/24.04L @STP] x [28.32 L/1cf][32]

$$CC_C = CH_{4(C)} \text{ x } 18.25\ (Mg/yr)^{33} \qquad \text{(Equation 50)}$$

CC_C: Carbon credits from combustion (credits/year)

For EF: 5,311 Credits =291 (Mg/yr) x 18.25 (Mg/yr)

3.10.2 Ex-Ante Method

The methane emission calculated ex-ante based on the amount of the animal manure that would decay anaerobically in the absence of the project activity. Values for the listed parameters are quoted directly from the Chicago Climate Exchange (CCX) guideline tables (CCXa, 2009). Equations 51-52 show the calculation of the ex-ante method.

(Step 1)

$$CH_{4Manure} = \sum_{T,S} N_{(T)} \times EF_{(T,S,St)} \times SSCF_{(s)} \times MS_{(T,S)} \times P_{days} \qquad \text{(Equation 51)}$$

For EF: 301,673 Kg CH_4/period^{-1} = 1,500 Dairy Cows x .551 x 1.00 x 1.00 x 365 days

Where:

CH_4Manure = CH_4 emissions from manure management (kg CH_4 per period^{-1})

(Step 2)

$$CO_{2Baseline} = \frac{CH_{4Manure} \times GWP_{Methane}}{1{,}000} \qquad \text{(Equation 52)}$$

$$4{,}223\ (Mg\ CO_2/yr) = \frac{201{,}115 KgCH_4 \times 21}{1{,}000}$$

[32] (CCXa, 2009)
[33] Carbon credits per ton of methane combusted

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$N_{(T)}$= The number of animals in livestock species/category T. The possible livestock species are listed in the CCX guidelines.

EF(T,S,St)= A methane emission factor for livestock where (T)=livestock category, (S) manure management system, (St)=state. The baseline manure management system options are anaerobic lagoon, pit storage below animal confinement, liquid/slurry.

$SSCF_{(S)}$ = A solids separation correction factor for manure management system S (unitless fraction). For those systems that do not separate solids, or that utilize simple gravity separation of sand or other non-manure solids, the SSCF is equal to 1. Since this study does not include solids separation, a SSCF of 1 was used. CCX guidelines provide rules for other manure management systems.

$MS_{(T,S)}$= The fraction of livestock category T's manure handled using manure management system S (unitless fraction)

$GWP_{Methane}$= The global warming potential of methane (kg CO_{2e} to $Mg^{-1}CO_{2e}$). The CCX estimates it to be 21.

P_{days}= Number of days in the reporting period (days)

1,000= Mass conversion factor (kg CO_{2e} to $Mg^{-1}CO_{2e}$)

Table 10. Carbon Credit Summary

Carbon Credits	
Combustion Method (credits/year)	5,311
Ex-ante Method (credits/year)	4,223
Lowest Value	**4,223**

Table 10 summarizes the number of carbon credits that would be earned using both methods. The model is programmed to automatically select the lower of the two carbon credit values. In the present example, the ex-ante method is the lowest value and revenues would be based upon 4,223 carbon credits a year. Over the range of herd sizes tested in this study, the ex-ante method consistently produced the lowest carbon credit values.

3.11 Financing Options

The model is programmed to automatically calculate the loan amortization schedule for all items financed with debt. This includes any debt incurred in the initial investment as well as incidental purchases associated with O&M costs. The user must input the specific annual percentage rate (APR), loan term and total loan principal. The model calculates the total periodic loan payment (interest and principal) using the formula for the present value of an annuity. The assumption is made that the payments will be yearly. Any loans made for O&M are programmed to begin in the year they are entered from the O&M module. The user must enter the specifics of the major O&M loans.

Grant payments are also included in this section and are handled by the model based upon the period of the grant and the number of payments per year. Any quarterly payments are aggregated into a yearly payment using Equation 53. The example provided is for the USDA Renewable Energy for American Program (REAP) which awards a maximum of 25% of the total project cost.

$$G_{YP} = (G_A / (G_{NP} \times G_D)) \times G_{NP} \qquad \text{(Equation 53)}$$

G_{YP} : Yearly grant payments
G_A : Total grant award
G_{NP} : Number of grant payments
G_D : Duration of grant

For EF: $259,510 = ($259,510 / (3 payments x 1 year)) x 3 payments

In the example, the yearly grant payments are equal to the total award amount since the grant is only for one year. Certain federal grants, however, may have a longer duration which makes the formula necessary to calculate the yearly payments.

3.12 Capital Budgeting Analysis

The costs and revenues from the various modules are then connected to an income statement assuming a 15 year project period. The required return to total capital was assumed to be 10.0% and then adjusted for taxes (1- Tax Rate). This made the adjusted after-tax return to total capital 6.66%. The weighted average cost of capital (WACC) was not used in this model in order to account for the lower interest rates on debt available to renewable energy projects receiving federal loan guarantees. Instead, interest was included as an operating expense and principal payments were deducted from after-tax cash flows. All analyses in this study assume a USDA grant covering 25% of the total investment cost and a loan guarantee covering 50%. The assumption is made that the loan guarantee would allow a farm to obtain debt at a 6% annual rate. This was considered a typical funding scenario for a Michigan digester.

In order to analyze the profitability of the digester system the net present value (NPV), internal rate of return (IRR) and payback period were calculated. The tax rate was calculated by aggregating all applicable tax rates in the state that would apply to a dairy farm.

$$TR = (T_{FP} + T_S) + T_{SE} \qquad \text{(Equation 54)}$$

TR: Tax rate (%)
T_{FP}: Federal personal tax rate (%)
T_{SE}: Self employment tax rate (%)

For EF: 33.45% = 15% + 4.35% + 14.1%

The model was then run on the 1,000 cow example dairy using NPV, IRR and payback period. Revenue streams include: electricity sales, RECs, carbon credits and propane offsets (from waste heat). In addition, this scenario assumes only dairy manure as a feedstock. All assumptions are listed in Table 11.

Table 11. Assumptions for 1,000 Cow Example

Influent	
Herd Size	1,000
Daily Flow Rate (gpd)	29,950
Biogas Production	
Methane concentration (%)	60
Biogas Yield (ft3/lb VS)	4.3
Electricity Generation	
Online Time (%)	90
Engine Efficiency (%)	35
Engine Generator Size (kW)	
Surplus Sale and Buy-All Sell-All	160
Net Metering	105
Heat Recovery Efficiency (%)	40
Parasitic Energy Requirement (%)	2

Table. 11 Assumptions for 1,000 Cow Example (Continued)

Digester Tank and Heating			
Heat Loss (%)	5		
Total Solids (%)	8		
Design Temp (°F)	95		
Hydraulic Retention Time (days)	20		
Boiler Efficiency (%)	80		
Pricing			
Carbon credits ($/credit)	2		
REC's ($/credit)	26.5		
Propane gas[34] ($/gallon)	2.31		
Retail Electricity ($/kWh)	0.0988		
Table Continued			
	Surplus Sale	Buy-All Sell-All	Net Metering
Simple Payback Period, years	15+	15+	15+
IRR on Equity	N/A	N/A	-17.83%
Net Present Value on Equity	-$734,075	-$760,599	-$560,519
After Tax Required Return to Equity	6.66%	6.66%	6.66%
Tax Rate	33.45%	33.45%	33.45%
Total Initial Investment	$1,038,040	$1,038,040	$909,893
Borrowed Capital for Initial Investment	$519,020	$519,020	$454,946
Debt as Percentage of Initial Investment	50%	50%	50%
APR	6%	6%	6%
Grant Funds	$259,510	$259,510	$227,473
Grants as Percentage of Investment	25%	25%	25%
Equity Invested Net of Grant Payments	$259,510	$259,510	$227,473

In this example, the digester system produces negative returns on investment under all three electricity purchase agreements. The internal rate of return is unable to be calculated under the surplus sale and buy-all sell-all agreements due to negative after-tax cash flows later in the project period. The payback period exceeded the project period of 15 years for all three agreements. Also, note that a digester system under a net metering agreement involves a lower initial investment cost. As explained in Chapter 2 Section 2.9.3, this is because a net metering agreement limits the size of the engine-generator to

[34] All propane offsets in this study were achieved using waste heat.

match the electrical need of the farm. Even with a smaller engine-generator and lower electricity production, net metering is the most favorable agreement at a herd size of 1,000 cows. This is because of policy benefits involving less utility company charges and a higher value for electricity produced by the digester. A comparison of the three electricity purchase agreements will be covered in more detail in Chapter 4.

3.13 Verification of Model

The default value investment and baseline biogas production modules were verified against several case studies which are publicly available through Cornell and Pennsylvania State Universities. Specific values for the methane concentration, online time, electrical conversion and heat recovery efficiency were not provided in the study and were taken from industry standards. The values were set as a constant in the model for all three digester systems examined.

3.13.1 Test Farm 1

The Sheland Farms Digester in New York is a vertical complete mix design with manure scraped from free stall barns. The farm installed a vertical complete mix digester as a solution to both increasing electrical and purchased bedding costs. The digester processes 14,000 gallons per day of barn effluent from 560 cows[35] as well as pre-digested solid-liquid separator liquid (SLS) effluent. The system has a 125-kW Caterpillar engine generator and was recorded as using an average 30 ft^3/minute of biogas to generate 80 to 85 kW of power (Pronto and Gooch, 2009). Details are provided in Tables 12-14.

[35] No breakdown given between lactating and dry cows

Table 12. Sheland Farms Inc. Case Study Inputs

Herd Size:	560
Design Temp, (°F):	100
Estimated Daily Flow Rate, (gpd):	14,000
Hydraulic Retention Time, (days):	17
Influent Composition	manure and solid-liquid separator liquid effluent

Table 13. Sheland Farms Inc. Case Study Outputs

	Case Study	**Model**
Tank Volume, (gallons)	238,000	262,000
Average Electricity Production, (kW)	80-85	92
Average Biogas Used, (ft3/minute)	30	28
TS Content, (%)	Not Given	9.6
Total Project Cost	$1,199,717	$669,592

Table 14. Model Assumptions for Test Farm 1

Methane Concentration, (%)	60
Engine Efficiency, (%)	35
Online Time, (%)	90
Heat Recovery Efficiency, (%)	40

In terms of the model outputs, the electricity production predicted by the model is slightly higher than the recorded values. This could be explained by either a lower engine efficiency on the actual farm engine-generator or possible volatile solids loss from the pre-digestion solid-liquid separator included in the system. The difference in predicted tank size could be due to the amount of freeboard space added. The model assumes a value of 10%.

One main discrepancy, however, is the difference in the total project costs. When examining the budget provided in the case study, the engineering design is budgeted at $200,000, whereas the model estimated it at $42,888. In addition, the biogas utilization building in the case study cost an estimated $232,917, whereas the model estimates the building to cost $15,000. Lastly, the case study includes $100,000 for miscellaneous costs which include construction supplies and materials, employee travel and shipping charges for equipment and materials. The default value module does not include a miscellaneous category, but does allocate $26,805 for contingency costs to cover cost overruns and delays. As explained in Section 3.1, all investment costs calculated in this study are benchmarked against the EPA AgSTAR cost curve. It is unclear whether this particular digester was overpriced or if the model undervalued the investment.

3.13.2 Test Farm 2

The Penn England Digester in New York is a mixed loop, partially above ground tank design. The manure collection system is connected to free stall barns which are scraped continuously. The milk parlor and holding pen are flushed 3 times per day and this flush water is also combined with the digester influent. The digester is fed with 18,200 gallons of raw manure per day in batches and an additional 6,000 gallons of parlor water. After 10 months operation the production was recorded at between 110 and 140 kW, averaging 120 kW (Pennsylvania, 2007). Tables 15-17 provide details.

Table 15. Penn England Farm (Mixed Loop) Case Study Inputs

Herd Size	720 Lactating and 80 Dry
Design Temp,(°F)	100
Hydraulic Retention Time,(days)	20
Influent Composition	manure and parlor water

Table 16. Penn England Farm (Mixed Loop) Case Study Outputs

	Case Study	Model
Average Electricity Production, (kW)	110-140	119
Daily Flow Rate, (gpd)	24,200	22,480
Tank Volume, (gallons)	525,000	494,560
TS Content, (%)	8 to 9	8.2
Total Project Cost	$1,140,000	$810,444

Table 17. Model Assumptions for Test Farm 2

Model Assumptions	
Methane Concentration, (%)	60
Engine Efficiency, (%)	35
Online Time, (%)	90
Heat Recovery Efficiency, (%)	40

The predicted electricity production is within the ranges listed in the case study. The tank size estimated by the model is 5.8% less than the actual volume, but could also be explained by a difference in freeboard space added.

In terms of the total project costs, the values calculated by the model are relatively close to this case study. The difference in cost is attributed to a power prime mover (CHP) for $135,000 and biogas conditioning equipment for $50,000 which is not included in the default value investment module.

Chapter 4: Results and Analysis

This chapter is separated into three main sections. Section one is a continuation of the 1,000 cow example described in Chapter 3 and is separated into two parts. The first is a series of sensitivity analyses which examine the price of retail electricity, the value of excess electricity produced, carbon credits and RECs. The second is a scenario examining the co-digestion of ethanol syrup to increase electricity production. Section two is focused on demonstrating the model's use as a tool for engineers seeking to optimize and/or estimate digester performance. Key variables which have a significant impact on performance were chosen for analysis including the total solids concentration, volatile solids loss and operational online time. The final section analyzes the digester return on investment from each of the three electricity purchase agreements over a range of herd sizes. In particular, specific aspects of Michigan's net metering policy and standby charges were analyzed in hypothetical situations. Recommendations were then made based on the results in order to make current energy policies more favorable for anaerobic digesters.

All sensitivity analyses and scenarios were tested using the default investment and baseline biogas production modules of the model. In each scenario/analysis, the after-tax net present value (NPV) of the digester investment was calculated and the results compared under the three electricity purchase agreements (surplus sale, buy-all sell-all and net metering). Although the model is also capable of measuring the return on investment using the internal rate of return and payback period, the after-tax NPV was best suited for the purposes of this study.

4.1 Section One - 1,000 cow Example

This section is separated into two parts and is based on the 1,000 cow example described in Chapter 3. Part I is a series of sensitivity analyses which examine the price of retail electricity, the value of excess electricity produced, carbon credits and RECs. Part II is a scenario examining the co-digestion of ethanol syrup to increase electricity production.

4.1.1 Part I Price Sensitivity Analyses

With the 1,000 cow herd example, the total project cost was estimated to be approximately $1,038,040 with an average yearly output of 159 kWh/hr for a total output of 1,395,616 kWh/year. The average yearly output accounts for engine-generator downtime, the parasitic energy load required to run the digester system and seasonal variations in electricity production. For modeling purposes, the average monthly output was used as an estimation of the engine-generator size needed for the surplus sale and buy-all sell-all agreements. Therefore, an engine-generator size of 160 kW was assumed in this section. With net metering, however, the engine-generator must be sized to match the electricity consumption needs of the farm. With the 1,000 cow dairy, a nameplate capacity of approximately 105 kW would be used based upon the maximum hourly electricity demand (kW) over a 12-month period estimated by the model. The model estimated demand by using actual data from the Michigan case farm and scaling the values to the needs of a 1,000 cow dairy. With the 105 kW engine-generator, the average yearly output would then be 93 kWh/hr assuming a 90% online time and a parasitic energy load that consumes 2% of the electrical output. All assumptions used in section one (Parts I and II) analyses are listed in Tables 18-19.

Table 18. Section One Assumptions - 1,000 Cow Dairy Sensitivity Analysis

Influent	
Herd Size	1,000
Daily Flow Rate (gpd)	29,950
Biogas Production	
Methane concentration (%)	60
Biogas Yield (ft3/lb VS)	4.3
Electricity Generation	
Online Time (%)	90
Engine Efficiency (%)	35
Engine Generator Size (kW)	
Surplus Sale and Buy-All Sell-All	160
Net Metering	105
Co-digestion	500
Heat Recovery Efficiency (%)	40
Parasitic Energy Requirement (%)	2
Digester Tank and Heating	
Heat Loss (%)	5
Total Solids (%)	8
Design Temp (°F)	95
Hydraulic Retention Time (days)	20
Boiler Efficiency (%)	80
Pricing	
Carbon credits ($/credit)	2
REC's ($/credit)	26.5
Propane gas[36] ($/gallon)	2.31
Retail Electricity ($/kWh)	0.0988
Financial Inputs	
Return on Equity (%)	10
Tax Rate (%)	33.45

[36] All propane offsets in this study are achieved using waste heat.

Table 18. Section One Assumptions - 1,000 Cow Dairy Sensitivity Analysis (Continued)

160 kW Engine-Generator	Total Project Cost			
	$1,038,040			
USDA REAP Funding	Total Principal	Term	APR	Percent of Investment
Loan Guarantee	$519,020	15	6%	50%
Table Continued				
	Amount	Duration (yr)		Percent of Investment
Grants	$259,510	1		25%
105 kW Engine-Generator	Total Project Cost			
	$909,893			
USDA REAP Funding	Total Principal	Term	APR	Percent of Investment
Loan Guarantee	$454,946	15	6%	50%
	Amount	Duration (yr)		Percent of Investment
Grants	$227,473	1		25%
500 kW Engine-Generator	Total Project Cost			
	$1,294,335			
USDA REAP Funding	Total Principal	Term	APR	Percent of Investment
Loan Guarantee	$647,168	15	6%	50%
	Amount	Duration (yr)		Percent of Investment
Grants	$323,584	1		25%

Table 19. Section I Electricity Purchase Agreement Assumptions

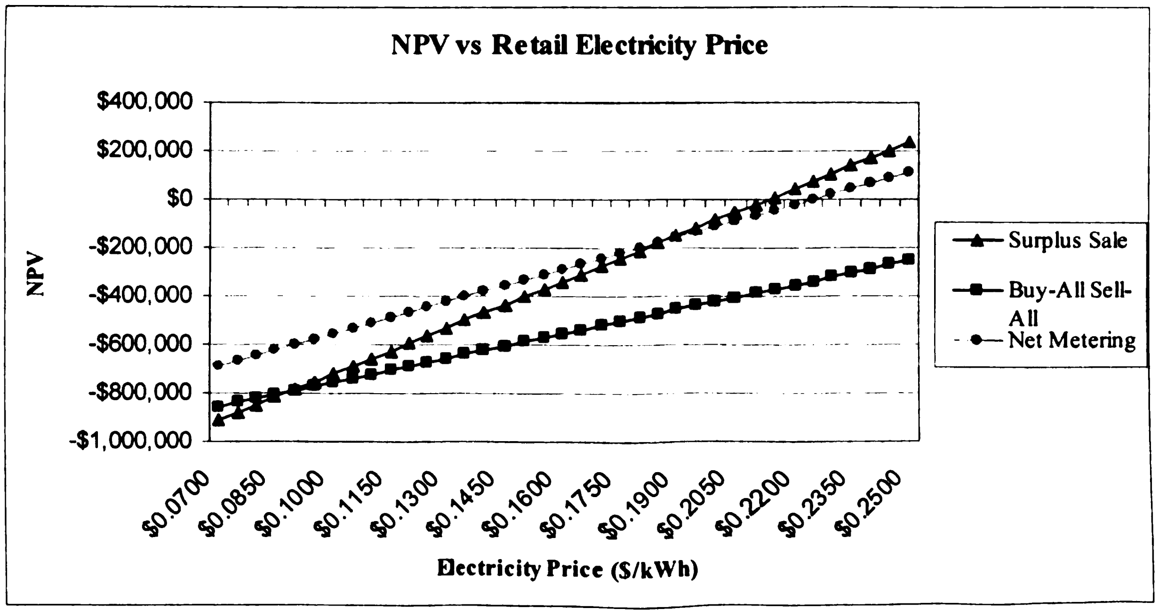
Policy Summary	**Surplus Sale**	**Buy-All Sell-All**	**Net Metering**
Standby Charge Threshold (kW)	100	100	150
Average Value of Excess Electricity ($/kWh)	$0.0435	$0.0435	$0.0612[37]
Administrative Charges ($/kWh purchased)	$0.0010	$0.0010	N/A
System Access Charge ($/month)	$100	$100	N/A

[37] This is referred to as the power supply component of the customer's bill.

4.1.1A Retail Electricity

The term retail electricity is referring to the price that the farm pays to purchase electricity from the utility company. This is also the electricity price that is offset with digester production under the surplus sale and net metering agreements. In this analysis, the value of the electricity produced was increased proportionately with the retail electricity price (Figure 5). This is because a high retail electricity price implies a higher cost of production which would also be reflected in the sell price (value of the electricity produced).

Figure 5. Sensitivity of NPV to Retail Electricity Prices



The breakeven price for retail electricity price was found to be $0.2135 per kWh under a surplus sale agreement and $0.2245 per kWh under net metering. Note that the breakeven price under net metering is very close to the breakeven price with a surplus sale agreement, even though the electricity production under net metering is 41% less than that of the other two agreements which utilize a larger engine-generator. There are three explanations for these results. First, a 1,000 cow dairy with a 105 kW engine-generator nameplate capacity will not pay standby charges. Under category 3 (Chapter 2) net metering, only farms with nameplate capacities greater than 150 kW will pay standby charges. Since these charges can represent 16% to 54%[38] of a farm's electricity revenues[39], the policy benefit actually offsets the decreased production levels from the smaller generator. Second, net metering customers receive a higher price for credited[40] electricity than under the other two agreements. Lastly, the net metering agreement is not subject to administrative charges per kWh of electricity purchased by the utility company or monthly system access charges. These differences are summarized in Table 19.

The breakeven price with net metering would also be the preferred agreement up to a price of $0.1850 per kWh. A surplus sale agreement, however, shows the steepest increase in NPV as the prices rise. This is because the larger engine-generator used with the surplus sale agreement allows the customer to offset more of their on-farm electricity consumption. The benefit of offsetting larger amounts of electricity usage becomes increasingly profitable at higher retail electricity prices despite the burden of standby charges.

Under a buy-all sell-all agreement, the after-tax NPV increases due to a rise in the value of electricity sold, but does not reach a breakeven price. This is because agreements which allow the farm to offset retail electricity purchases will experience the greatest

[38] The exact percentage depends on the retail electricity price. The higher the price, the lower the percentage that standby charges represent.
[39] Electricity revenues are defined as electricity offset by the digester, sold to the utility company or credited to the farm's utility bill in the case of net metering.

[40] Electricity that is credited to next month's bill is considered a revenue for the customer.

increase in return on investment from higher retail electricity prices. Note that a buy-all sell-all agreement is preferable to a surplus sale purchase agreement with retail electricity prices up to $0.0900 per kWh. This is due to the fact that no standby charges are required with a buy-all sell-all agreement[41] since on-farm electricity is not being offset. With prices higher than $0.0900, however, the benefits of offsetting on-farm electricity make buy-all sell-all a less desirable agreement for a farm with a milking herd of 1,000 cows.

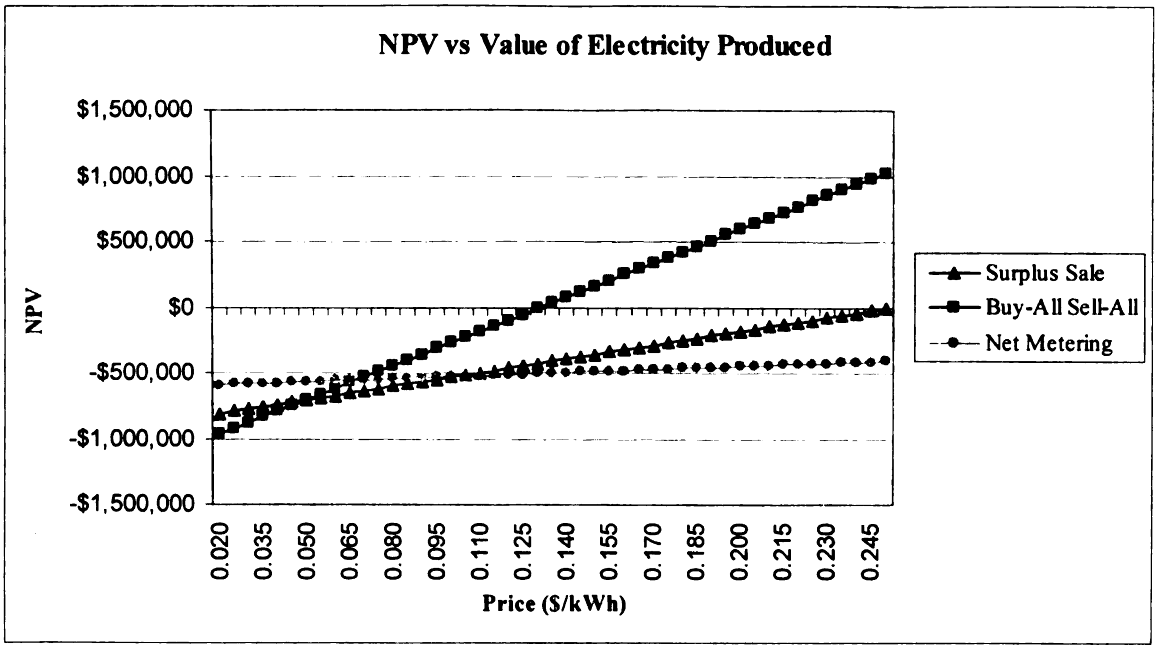
The Department of Energy's Energy Information Administration predicts electricity costs to increase steadily for the next 15 years. By the end of the project period, the average nominal price of commercial electricity in the U.S. is expected to be as high $0.134 per kWh on average. In states like California, the commercial electricity rate reached an average of $0.1638 per kWh during the summer of 2009 (US EIA, 2009)). The trend for higher electricity prices around the country suggests that a breakeven price of $0.2135 per kWh might be feasible in the future. In addition, this breakeven price is considered with the price of carbon credits and RECs held constant. In reality, increases in other revenues sources will likely decrease the breakeven price.

4.1.1B Value of Electricity Production

The value of electricity production refers to the price that the utility pays/credits the customer for electricity produced by the digester. Currently, customers are paid either the locational marginal price or the power supply component of their bill (net metering). This analysis considers a range of prices from $0.020 per kWh to $0.250 per kWh to examine the effect on the NPV of the digester investment (Figure 6).

[41] Buy-all sell-all agreements do not pay standby charges under any engine generator size since no on-farm electricity is offset.

Figure 6. The Sensitivity of NPV to the Value of Electricity Produced



The results show distinct effects under each agreement. The buy-all sell-all agreement is the most sensitive to increases in the value of digester electricity with a breakeven price of $0.1315 per kWh. This is because all electricity is sold and therefore the customer will benefit the most from increased compensation from the utility company. The surplus sale agreement has a higher breakeven price of $0.2530 per kWh since only the excess electricity is sold back to the grid. Even though a surplus sale agreement involves offsetting on-farm electricity at the higher retail rate, standby charges significantly decrease profitability. The model calculates that 42%[42] of the farm's electricity revenues will be used to pay standby charges under a surplus sale agreement. Net metering is clearly the least favorable agreement as the price increases and does not reach a breakeven point within the range of prices tested. This is because the 105 kW engine-generator allowed under net metering reduces the amount of excess electricity that can be

[42] At a retail electricity price of $0.0988 per kWh

credited at the higher prices. Note that net metering shows higher returns to investment than a buy-all sell-all agreement for prices up to $0.0650 per kWh. This is because offsetting electricity at the retail rate and no administrative or system access charges makes the returns under net metering higher in this range. Above $0.0650 per kWh, however, it becomes more profitable to sell the entire output from the digester than to offset on-farm consumption and pay standby charges. In comparing net metering to a surplus sale agreement at lower prices, net metering is also preferable, but up to the higher price of $0.1000. This is because a surplus sale agreement is less sensitive to increases in the value of electricity produced. Above a price of $0.1000 per kWh, the surplus sale agreement allows the farm to earn more revenues from the increasing value of the digester electricity produced. This is due to the larger engine-generator permitted under this agreement (160 kW).

When considering these results in terms of energy policy, the breakeven prices can be used as supporting evidence in the setting of feed-in-tariffs. Feed-in-tariffs are prices paid per kilowatt-hour of electricity generated by a renewable energy system and are currently utilized in several European countries and Canada. The price that is paid is based on the cost of the electricity produced plus a reasonable profit for the producer. They are differentiated by technology and can also be further differentiated within each technology by project size or productivity (Gipe, 2009).

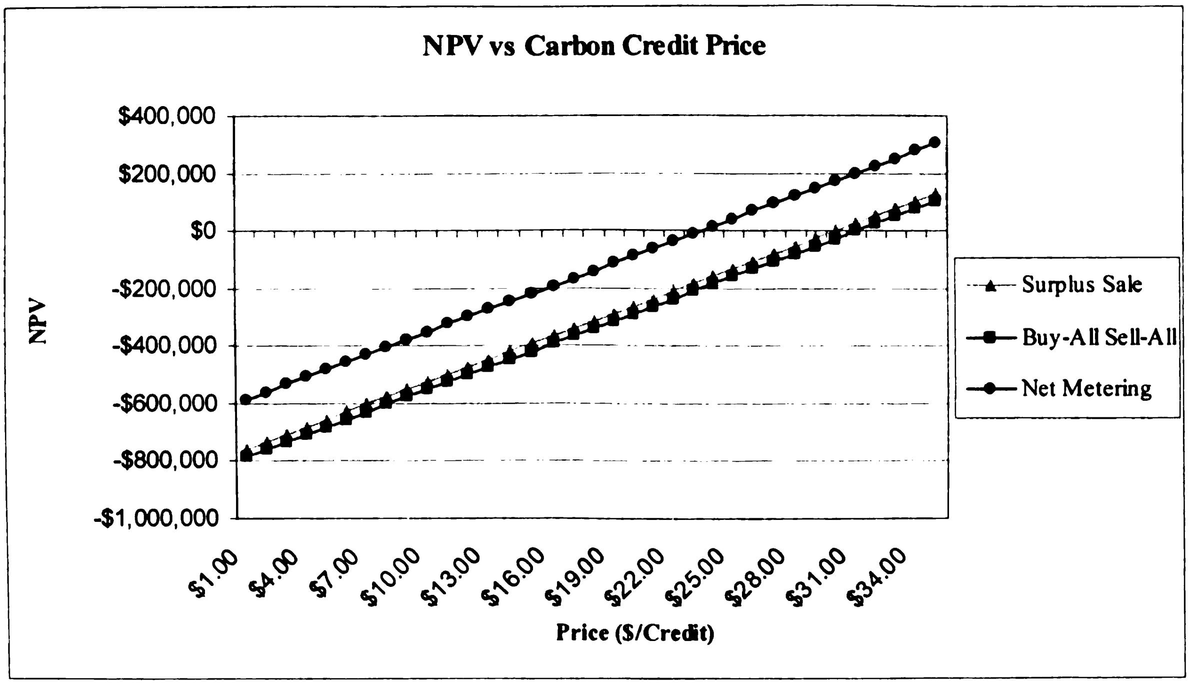
Michigan also is pursuing similar legislation and in February, 2009, House Bill 4137 was proposed which specifies feed-in-tariff prices by technology. The bill identifies a tariff of

$0.125 for methane digesters with an engine generator nameplate capacity between 150 kW and 500 kW. The breakeven price of $0.1315 calculated by the model supports the price in the legislation only if considering a buy-all sell-all agreement. Under a surplus sale agreement, however, the tariff would need to be at least $0.2530 for the investment to breakeven. Therefore, a farm owner would want to consider future energy legislation before deciding which electricity purchase agreement to select.

4.1.1C Carbon Credits

Methane is a greenhouse gas that is approximately twenty-three times more powerful per unit at trapping heat than carbon dioxide (CCXb, 2009). Its destruction or avoidance has created potential for anaerobic digesters to earn additional revenue in the form of carbon credits. Under CCX rules methane is credited at a rate of 21 metric tons CO_2 for each metric ton of methane avoided. With the 1,000 cow example, the breakeven price for carbon credits is $30.06 per credit with a surplus sale agreement, $31.07 per credit with a buy-all sell-all agreement and $23.43 with net metering (Figure 7). With carbon credits, net metering is slightly less than the other two agreements due to the policy benefits cited in the retail electricity price sensitivity analysis. In this scenario, the number of carbon credits is determined by the amount of methane that is prevented from entering the atmosphere through the installation of the digester (Methane Combustion Method). Through this method, the amount of revenue earned from carbon credits will be constant for a given herd size, climate and manure management practice and will not be affected by the amount of biogas flared or sent to the engine-generator. The alternative method (Ex-Ante Method) of earning credits involves the combustion of methane through the engine-generator or the flare. In this example, the combustion method calculates a higher level of methane emission reductions. Since the CCX selects the method which calculates the lowest level of reductions, the combustion method was not used in the analysis.

Figure 7. Sensitivity of NPV to Carbon Credit Prices

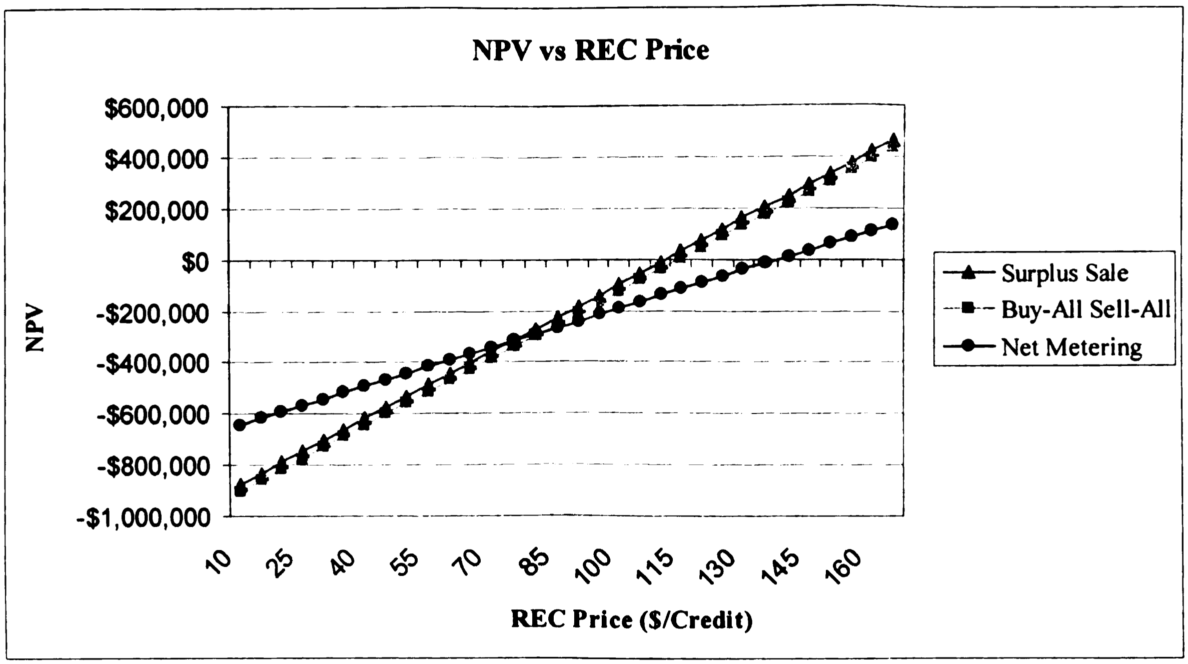


While the price of carbon credits over the past year has been as low as $0.15, current climate change legislation has the potential to raise the price of carbon credits much higher. Perhaps a predictor of future prices is the European Climate Exchange which had an average price of $17.81 in 2009. If these prices are indicative of the future carbon market in the U.S., the breakeven values calculated could become feasible. It is important to note that a cap and trade system will not only have the effect of increasing the price of carbon credits, but will also increase the price of electricity produced from fossil fuels (e.g., coal). If an increased price of both carbon credits and electricity were considered together in the same scenario, the breakeven price for carbon credits depicted in Figure 7 would be lower.

4.1.1D Renewable Energy Credits (RECs)

A Renewable Energy Credit (REC) is a payment per Megawatt (1,000 kWh) of electricity produced from a renewable energy system. The breakeven prices for RECs are $111.40/MW for a surplus sale agreement, $114.50/MW for a buy-all sell-all agreement and $138.10/MW for net metering (Figure 8). From Figure 8, it is evident that increasing REC prices have less of an effect on the NPV of a digester under net metering. This is consistent with the fact that net metering requires a farm to install a smaller engine-generator that is sized to meet the energy consumption needs of the farm. With a smaller generator, less electricity is produced which limits the quantity of RECs that can be sold by the farm. Under the surplus sale and buy-all sell-all agreements, a larger engine-generator allows for a larger increase in revenues from higher REC prices. Note that net metering actually has a higher after-tax NPV than under a surplus sale agreement for REC prices up to $74.50/MW. It is also higher then under a buy-all sell-all agreement for REC prices up to $81.50/MW. This is due to the policy benefits cited in Section 4.1.1A Retail Electricity.

Figure 8. Sensitivity of NPV to Renewable Energy Credit Prices



The market for RECs is largely dedicated by utility companies which decide the price they are willing to offer for each REC. The market for RECs exists primarily as a means for companies or other entities to comply with renewable portfolio standards. In this study, a price of $26.50/MW was taken from a Michigan case farm, but recent contracts from Consumers Energy list prices of roughly $30 to $50/MW per REC. Within that price range, the model suggests that a net metering agreement would be preferable. When considering the long run, however, higher REC prices would make net metering a less favorable option.

4.1.2 Part II Co-digestion of Ethanol Syrup

This scenario examines the number of truck loads of ethanol syrup that are needed in order for the digester system to reach a positive NPV on a 1,000 cow dairy. When a farm decides to co-digest ethanol syrup, the amount added is determined by the capacity of the truck and number of times the farm is willing to travel to the ethanol plant for pickup. In this model, the assumption is made that trips will only be made to the plant when the truck is loaded to full capacity. The price of fuel, labor costs and the distance traveled are also likely to be factors which influence a farmer's decision. Therefore, when calculating the NPV, the cost of the syrup, fuel (including vehicle gas mileage), labor, truck capacity, and trip duration (a function of distance, speed and time needed for loading) are used to calculate the full cost of the ethanol syrup.

4.1.2A Scenario

Once the feedstock has been purchased and brought back to the farm, another key decision is the amount added each day. Adding the full amount at once may shock the system and result in increased acid levels and foaming. In order to account for this factor, the assumption was made that 50% of the syrup would be added over a period of two days[43]. It is important to consider that a farm may not want to purchase additional syrup if excess supply exists. This scenario is set up under the assumption that all existing supply will be utilized before new truck loads are purchased.

In order to take advantage of the increased biogas production, the assumption was made that at larger engine-generator size would be necessary than if manure was the sole feedstock. For surplus sale and buy-all sell-all agreements, a 500 kW engine-generator was assumed compared to 160 kW with no syrup added in Part I. The 500 kW size was chosen as an example since it would allow for enough electricity production to produce a positive digester NPV. The initial investment cost for the electrical generation equipment

[43] As an example, if 100% of the syrup were added at each feeding then there would be no excess supply.

was adjusted accordingly. With net metering, however, the utility company limits the size to fit the customer's consumption needs and the model was run assuming a 105 kW engine-generator.

The scenario assumes that 7 tons of ethanol syrup are loaded into the truck each trip which is approximately 5.60% of the total influent to the digester. The value of 7 tons was determined from scaling back actual values obtained from the Michigan case farm. Other assumptions such as trip duration, truck speed, fuel prices and labor costs, are highly variable and an attempt was made to choose the most reasonable values possible for the analysis (Table 20).

Table 20. Co-digestion Scenario Assumptions Summary

Variables	Assumptions
Quantity (tons)	7
Price (\$/ton)	5
Feedstock Added (%/day)	50
Days of Supply	2
Percentage of Mixture (%)	5.60
Distance (miles)	60
Average Speed (mph)	65
Time for Loading (hrs)	1
Fuel Economy (mpg)	15
Fuel Price (\$/gallon)	2.50
Total Trip Duration (hrs)	1.92

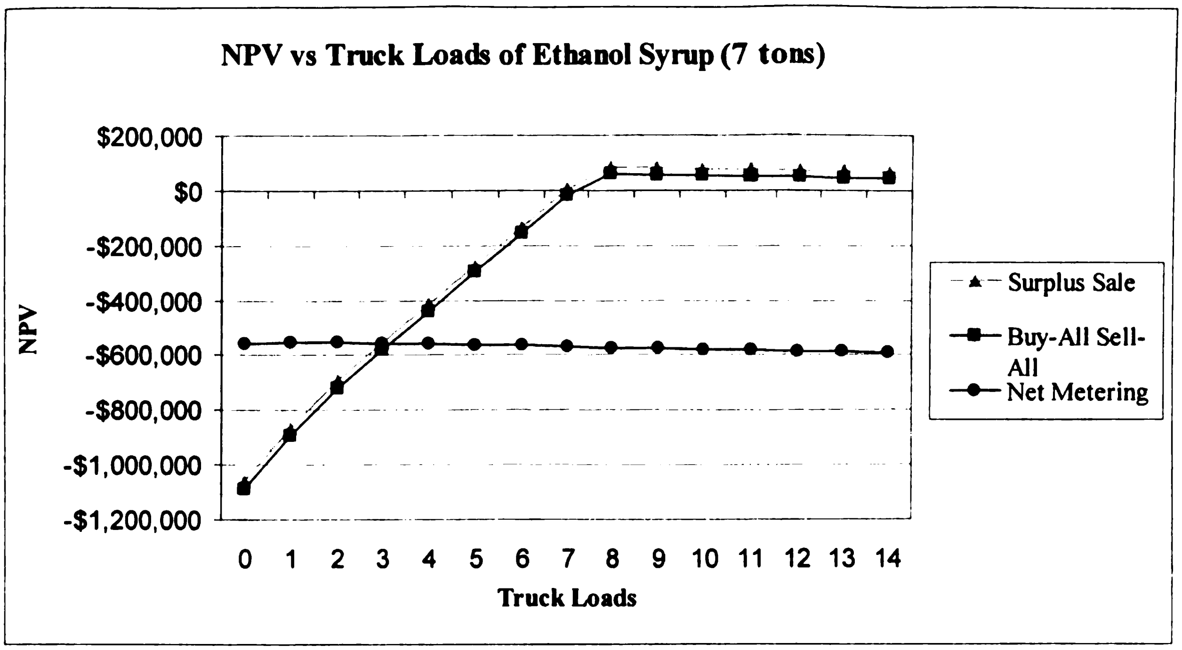
Table 21 compares the number of truck loads per month and the percentage of ethanol syrup added on a daily basis to the corresponding increase in average yearly electricity production (kWh/hr) from the digester. The column "Surplus Sale & Buy-All Sell-All" represents the electricity production assuming no limitation on the engine-generator size. As mentioned in Part I, net metering limits the engine-generator size to the electricity consumption needs of the farm. Therefore, increased biogas production from the co-digestion of additional feedstocks has an extremely limited effect on electricity production. The only noticeable effect is that the parasitic energy load from the digester no longer reduces the average yearly electricity production after one truck load of ethanol syrup.

Table 21. Co-digestion of Ethanol Syrup and Electricity Production (7 ton loads)

Average Yearly Electricity Production (kWh/month)			
Truck Loads	% Added Daily	Surplus Sale & Buy-All Sell-All	Net Metering
0	0	159	93
1	2.72	203	95
2	5.30	241	95
3	7.75	278	95
4	10.07	316	95
5	12.28	353	95
6	14.39	391	95
7	16.39	428	95
8	18.30	450	95
9	20.13	450	95
10	21.88	450	95
11	23.55	450	95
12	25.1	450	95
13	26.69	450	95
14	28.17	450	95

In Figure 9 on average, one truck load of ethanol syrup increases the average yearly electricity production by 36 kWh/hr. At 8 truck loads per month, the engine generator is producing at its maximum level of 500 kW and sufficient waste heat is produced to avoid the use of the boiler. This results in an average yearly electrical production of 450 kWh/hr given an online time of 90%.

Figure 9. The Effect of Each Tuck Load (7 tons) of Ethanol Syrup on NPV



Given the assumptions made, the system will require 7 truck loads of ethanol syrup per month with a surplus sale agreement and 8 loads per month with a buy-all sell-all agreement in order to reach a positive NPV. The difference in the number of truck loads is attributed to a slight advantage with the surplus agreement given the retail electricity prices and the value of electricity produced assumed in the model. Since a net metering agreement prevents a farm from realizing increased electricity production from co-digestion, adding ethanol syrup actually decreases the return on investment. This is because the farm would be incurring feedstock related costs without increasing revenues. When comparing the results of this analysis to the Michigan Department of Environmental Quality (MDEQ) organics residuals exemption discussed in Chapter 2, the hypothetical farm operation could have a profitable investment and still be in compliance with state laws. Note that at 8 truck loads per month, the ethanol syrup entering the digester each day comprises roughly 18% of the total mixture (manure, parlor/dilution water and ethanol syrup). This fits within the 20% limit stated in the MDEQ exemption.

4.3 Section Two - Engineering

The next section demonstrates the model's use as a tool for engineers to analyze and predict digester performance. While a variety of parameters can be tested with this model, three key variables (total solids concentration, volatile solids loss, and online time) were chosen which can significantly affect digester performance. This will help provide insight into how system performance directly relates to profitability. All examples in Section Two involve a herd of 1,000 lactating cows and many of the same assumptions as Section One (Table 18). In this section, however, a larger engine-generator was selected for analysis in order to more effectively demonstrate the use of the model when other assumptions are changed. A list of assumptions is presented in Table 22.

4.3.1 Total Solids Concentration

Table 22. Section Two Assumptions - Engineering

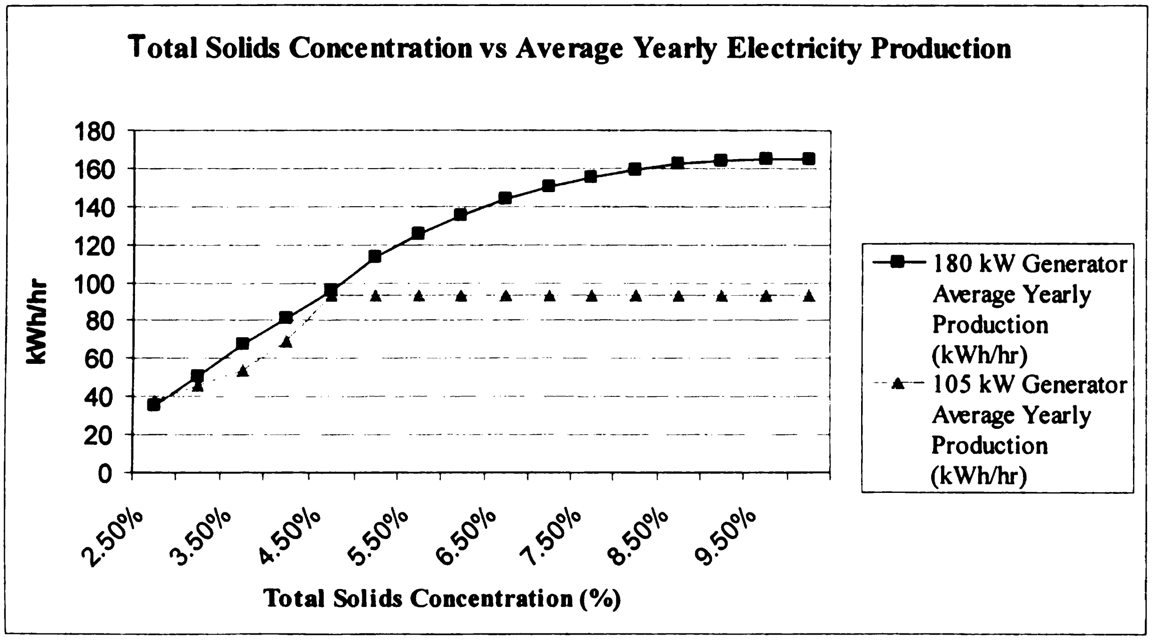
Influent	
Herd Size:	1,000
Daily Flow Rate (gpd)	29,950
Biogas Production	
Methane concentration (%)	60
Biogas Yield (ft3/lb VS)	4.3
Electricity Generation	
Online Time (%)	90
Engine Efficiency (%)	35
Engine Generator Size (kW)	
Surplus Sale and Buy-All Sell-All	180
Net Metering	95
Heat Recovery Efficiency (%)	40
Parasitic Energy Requirement (%)	2

Table 22. Section Two Assumptions – Engineering (Continued)

Digester Tank and Heating				
Heat Loss (%)	5			
Volatile Solids Loss (%)	0			
Total Solids (%)	Base Case Variable			
Design Temp (°F)	95			
Hydraulic Retention Time (days)	20			
Boiler Efficiency (%)	80			
Pricing				
Carbon credits ($)	2			
REC's ($)	26.5			
Propane gas ($/gallon)	2.31			
Retail Electricity ($/kWh)	0.0988			
Financial Inputs				
Return on Equity (%)	10			
Tax Rate (%)	33.45			
180 kW Engine-Generator	Total Project Cost			
	$1,038,040			
USDA REAP Funding	Total Principal	Term	APR	Percent of Investment
Loan Guarantee	$519,020	15	6%	50%
	Amount	Duration (yr)		Percent of Investment
Grants	$259,510	1		25%
105 kW Engine-Generator	Total Project Cost			
	$909,893			
USDA REAP Funding	Total Principal	Term	APR	Percent of Investment
Loan Guarantee	$454,946	15	6%	50%
	Amount	Duration (yr)		Percent of Investment
Grants	$227,473	1		25%

Figure 10 shows the relationship between the total solids concentration of digester influent and average yearly electricity production. As mentioned in Chapter 2, the total solids concentration decreases as water (parlor, rain) are mixed with the manure. In Michigan's climate, more liquid in the influent mixture increases the heating requirements of the digester and can decrease electricity production. In addition, investment costs increase due to the need for larger tanks and more related components. The following scenario analyzes this relationship between the total solids concentration of digester influent and electricity production.

Figure 10. Total Solids Concentration vs. Average Yearly Electricity Production

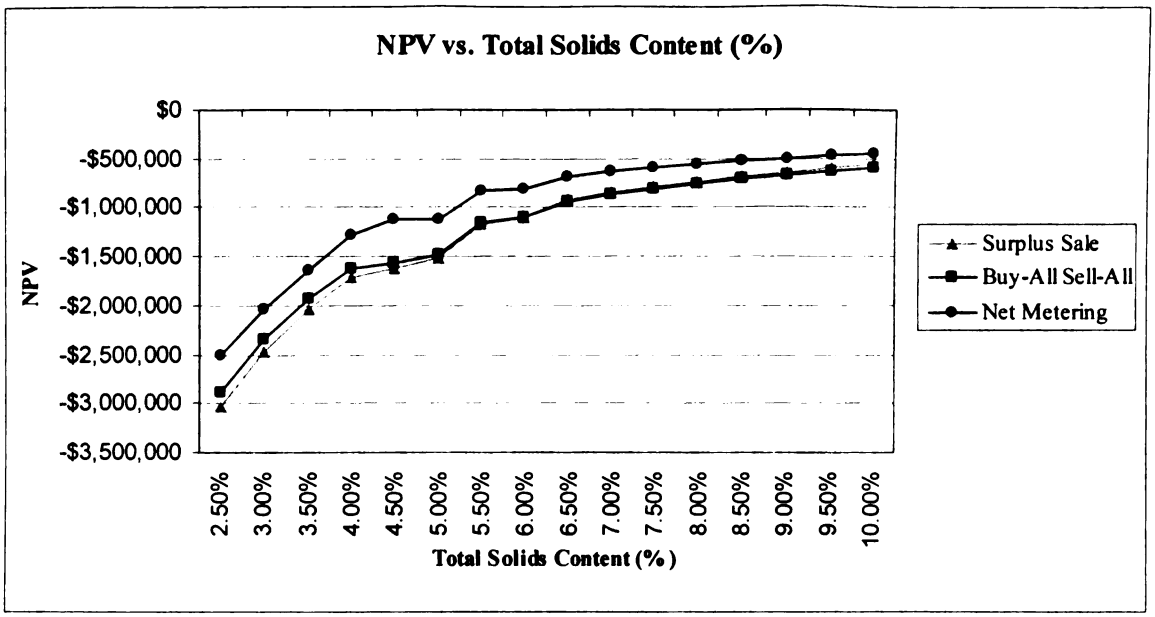


In Figure 10, average yearly electricity production with the 180 kW engine-generator represents the surplus sale and buy-all sell-all agreements. A 105 kW engine generator is assumed with net metering. Note that the average yearly production from the 180 kW engine generator increases with the total solids (TS) concentration. Specifically, between TS concentrations of 2.5% and 5.5%, every 1% increase in TS concentration raises the average yearly electricity production (kWh/hr) by an average of 30 kWh/hr. For TS concentrations greater than 5.50%, an increase in the TS concentration has a decreasing effect on the average yearly electricity production. This is because at higher TS concentrations, less biogas is required to run the boiler allowing more biogas to be sent to the engine-generator.

With the 105 kW engine-generator, at TS concentrations between 2.5% and 4.0%, every % increase in the TS concentration increases the average yearly electricity production by 20 kWh/hr. In this range, the digester system will experience significant waste heat deficits and the boiler will need to be used a minimum of 8 months out of the year. Beyond a concentration of 4.0%, electricity production is a constant 93 kWh/hr for TS concentrations ranging from 5.00% to 10%. This is because at TS concentrations above 5.00%, extra biogas can be burned in the boiler to meet digester heating needs without diverting biogas from the engine-generator. The extra biogas exists because the engine-generator is undersized for the biogas production of a 1,000 cow herd.

While Figure 10 only considers the effect of TS on average yearly electricity production, Figure 11 considers the entire digester investment. For example, at lower TS concentrations, higher quantities of water are present in the digester influent which requires a larger tank size and more related components. In addition to the higher investment costs, lower electricity production levels due to heat deficiencies also contribute to lower returns on investment at lower TS concentrations.

Figure 11. The Effect of Total Solids Concentrations on NPV



Across the levels tested, a buy-all sell-all agreement shows higher returns at lower total solids concentrations (2.50% to 6.0%) than the surplus sale agreement. This is because as the digester electrical output decreases with lower TS concentrations, the system is offsetting less on-farm electricity. On-farm electricity is valued at the commercial retail rate of $0.0988 which is roughly double the average monthly LMP which ranges from $0.037 to $0.052 in the model. As a result, standby charges, which are determined by the farm's peak usage, represent a larger percentage of the electricity revenues. Therefore, the cash flows at lower TS levels are significantly reduced. For example, at a TS concentration of 4%, the standby charge will use up 81% of electricity revenue[44] generated by the digester. At this level, a buy-all sell-all agreement would be preferable to offsetting on-farm electricity with a surplus sale agreement. Buy-all sell-all agreements are not subject to these charges.

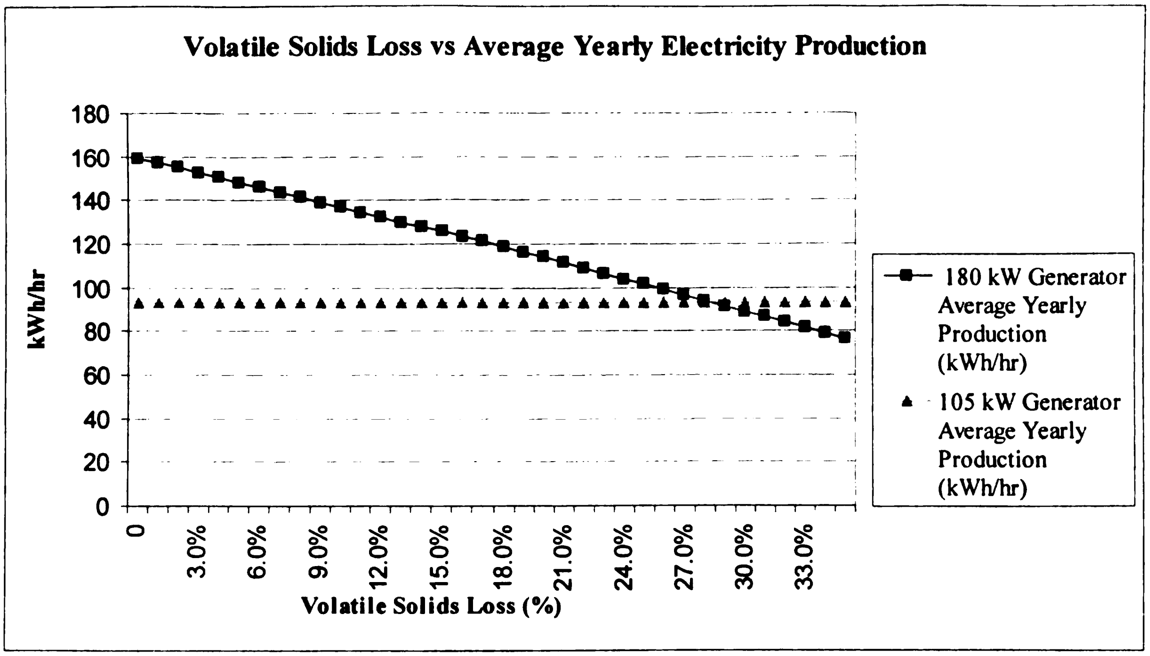
[44] Revenue is defined as offsets and sales

Despite the lower electricity production under the net metering, it produces higher returns than the other two agreements. This is due to the policy benefits mentioned in previous sections. It is important to keep in mind, however, that the results of this analyze are specific to a 1,000 cow milking herd and should not be used to make generalizations across a range of herd sizes. An analysis of each purchase agreement across a range of herd sizes is covered later in Section Three.

4.3.2 Volatile Solids Loss

The loss of volatile solids (VS) can often be attributed to manure pretreatment in which certain processes (e.g., mechanical separation, sand removal) can cause the loss of these solids. Since volatile solids are the energy producing portion of the manure or any other added substrate, their loss has a direct effect on the performance of the digester. The issues are similar to that experienced with low total solids concentrations, except that volatile solids losses will not increase the capital costs of the system. All assumptions from Table 22 are held constant expect that the total solids concentration is no longer the tested variable and is assumed to be 8%. Figure 12 shows the relationship between volatile solids loss and average yearly electricity production.

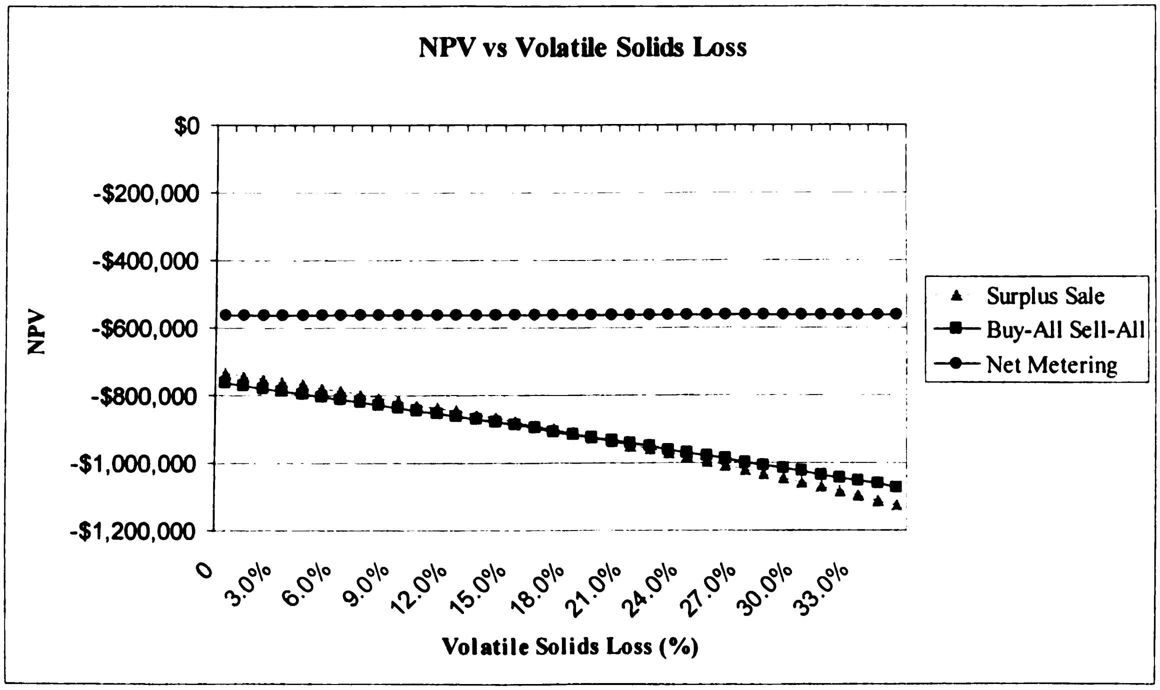
Figure 12. Volatile Solids Loss vs. Average Yearly Electricity Production



Note that with the 105 kW engine-generator, average yearly electricity production is not affected by volatile solids loss throughout the ranges tested. This is because since a 105 kW engine-generator is under sized for a 1,000 cow milking heard, the system can lose a minimum of 35% of its VS and still run the generator at its maximum capacity.

With a 180 kW engine-generator size, electricity production is more sensitive to losses in VS. Specifically, between the entire range of 0% to 35%, every 1% decrease in VS results in a 2.07% decrease in electricity production on average. Slightly larger decreases were observed at VS losses above 21%. Figure 13 examines the effect of VS losses on the NPV of the digester investment. On average, a 1% increase in VS loss decreases the NPV of the digester by 1.23% with a surplus sale agreement and 1.00% with a buy-all sell-all agreement. Net metering remains unaffected since extra biogas is available to achieve digester heating requirements without decreasing electricity production. Unlike the situation with TS concentrations, the capital investment does not change which explains a more linear trend in NPV across the range of solids losses tested. Even at a VS loss level of 0%, the net metering agreement still shows higher returns. This is explained by policy advantages outlined in section one of this chapter.

Figure 13. The Effect of Volatile Solids Loss on NPV

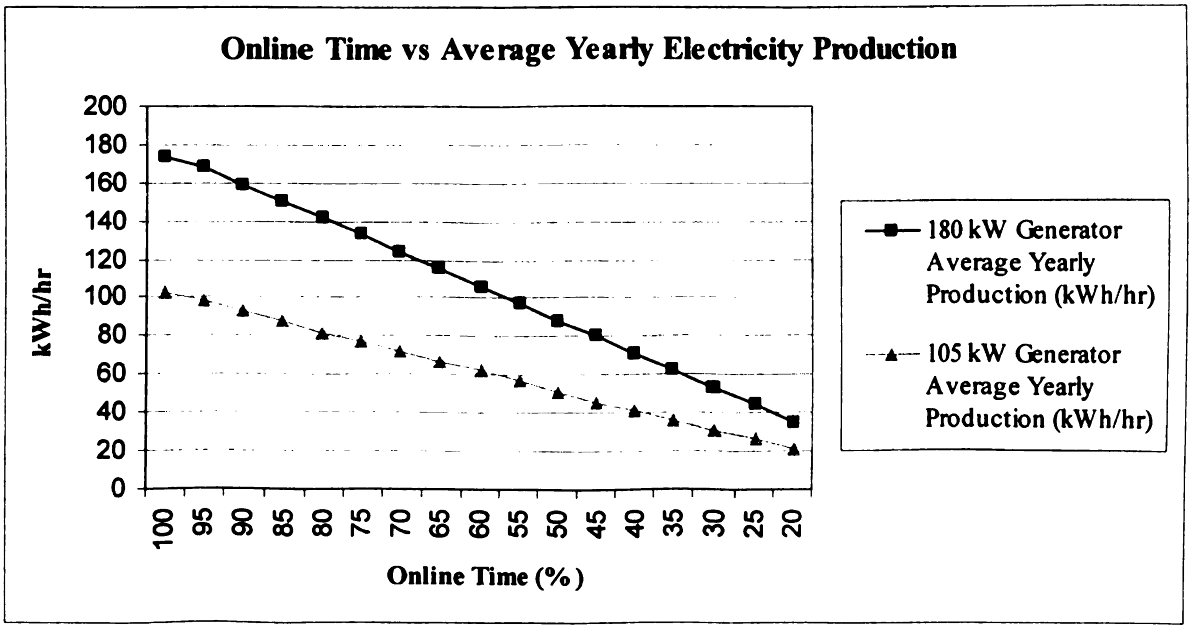


As with the analysis of TS concentrations, a buy-all sell-all agreement shows slightly higher returns than a surplus sale agreement at higher levels of VS loss. The explanation is the same in that as electricity production decreases under a surplus sale agreement, standby charges represent a larger percentage of electricity revenues. For example, with a VS loss of 30%, the standby charge uses up 65% of the electricity revenues generated by the digester. This suggests that a system with a potential for large losses in volatile solids would be not be well suited for a surplus sale agreement.

4.3.3 Online Time

The third key variable in the engineering section of the analysis deals with the operational online time of the engine generator. While 90% is considered as "good" performance by EPA AgSTAR's Farmware simulator, actual digester systems may experience a range of online times depending on the condition of the engine-generator and quality of the maintenance by farm operators. All assumptions from Table 23 are held constant expect that the total solids concentration is no longer the tested variable and is assumed to be 8%. Figure 14 shows the relationship between online time and average yearly electricity production.

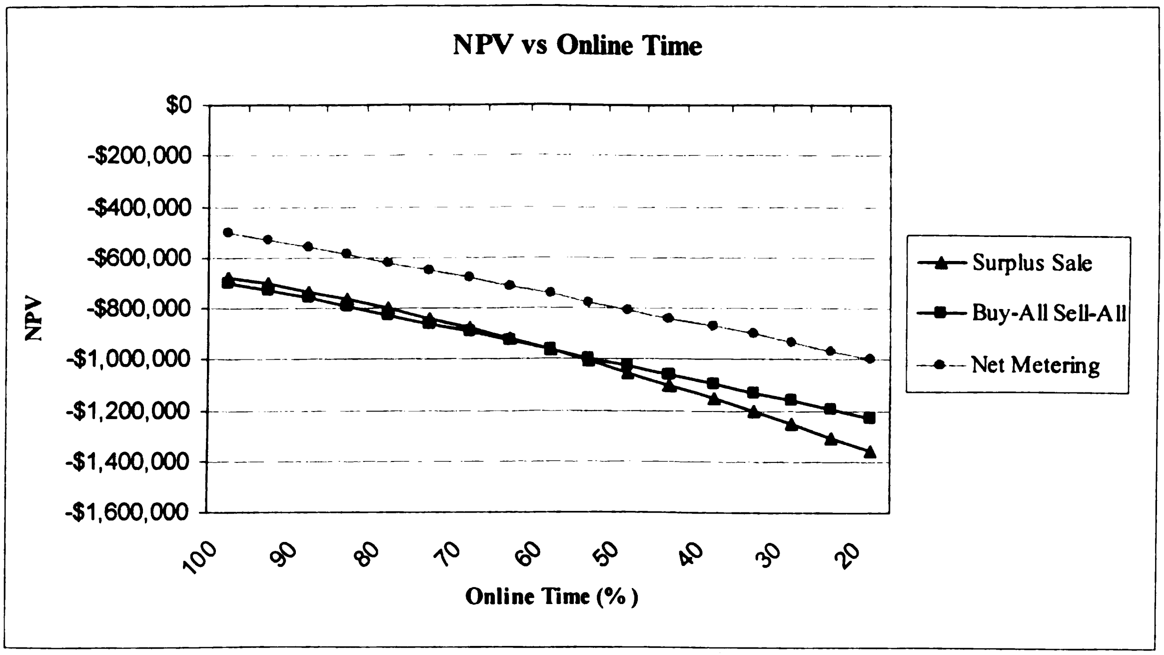
Figure 14. Online Time vs Average Yearly Electricity Production



In Figure 14, there is a linear decrease in the average yearly electricity production for both the 180 kW and 105 kW engine-generators. Every 10% decrease in online time, decreases the average yearly electricity production by 18 kWh/hr and 10 kWh/hr, respectively.

In Figure 15, note that the buy-all sell-all agreement shows higher returns than the surplus sale agreement for online times up to 60%. As with section 4.3.1 Total Solids Concentration, this is because as the digester electrical output decreases, the system is offsetting less on-farm electricity.

Figure 15. The Effect of Online Time on NPV



On-farm electricity is valued at the commercial retail rate which is roughly double the average monthly LMP. In addition, standby charges, which are a constant and determined by the farms peak usage, represent an increasing percentage of the electricity revenues. For example, at an online time of 80%, the associated standby charges use up 45% of the electricity revenue on average with a surplus sale contract. If this level decreases to 40%, standby charges use up 78% of the electricity revenues. At a level of 40%, a buy-all sell-all agreement would be preferable to offsetting on-farm electricity with a surplus sale agreement. At a level above 60%, however, the reverse is true. On average, every 1%

increase in online time, increases the return on investment by $8,555 with a surplus sale agreement, $6,591 with a buy-all sell-all agreement and $6,227 under net metering.

Lastly, net metering would be the preferred agreement throughout the range of online times tested. As mentioned in previous analyses, this benefit is specific to a 1,000 cow dairy and should not be taken out of context.

4.4 Section Three - Policy

4.4.1 Part I - Current Policy

The third component of this chapter analyzes how Michigan energy policy affects the return on investment of anaerobic digesters over a range of herd sizes. While the previous two sections dealt specifically with a 1,000 cow dairy, examining a range of herd sizes more effectively highlights the differences between the three electricity purchase agreements. Unless otherwise indicated, assumptions used in all sensitivity analyses performed in this section are listed in Tables 23-24.

Table 23. Section Three Assumptions- Policy

Influent	
Herd Size:	1,000
Daily Flow Rate (gpd)	29,950
Biogas Production	
Methane concentration (%)	60
Biogas Yield (ft3/lb VS)	4.3
Electricity Generation	
Online Time (%)	90
Engine Efficiency (%)	35
Engine Generator Size (kW)	
Surplus Sale and Buy-All Sell-All	180
Net Metering	95
Heat Recovery Efficiency (%)	40
Parasitic Energy Requirement (%)	2

Table 23. Section Three Assumptions- Policy (Continued)

Digester Tank and Heating				
Heat Loss (%)	5			
Volatile Solids Loss (%)	0			
Total Solids (%)	Base Case Variable			
Design Temp (°F)	95			
Hydraulic Retention Time (days)	20			
Boiler Efficiency (%)	80			
Pricing				
Carbon credits ($)	2			
REC's ($)	26.5			
Propane gas ($/gallon)	2.31			
Retail Electricity ($/kWh)	0.0988			
Financial Inputs				
Return on Equity (%)	10			
Tax Rate (%)	33.45			
180 kW Engine-Generator	Total Project Cost			
	$1,038,040			
USDA REAP Funding	Total Principal	Term	APR	Percent of Investment
Loan Guarantee	$519,020	15	6%	50%
	Amount	Duration (yr)		Percent of Investment
Grants	$259,510	1		25%
105 kW Engine-Generator	Total Project Cost			
	$909,893			
USDA REAP Funding	Total Principal	Term	APR	Percent of Investment
Loan Guarantee	$454,946	15	6%	50%
	Amount	Duration (yr)		Percent of Investment
Grants	$227,473	1		25%

Table 24. Current Policy Summary

Policy Summary	Surplus Sale	Buy-All Sell-All	Net Metering
Standby Charge Threshold (kW)	100	100	150
Average Monthly Value of Excess Electricity ($/kWh)	0.0435	0.0435	0.0612
Administrative Charges ($/kWh purchased)[45]	0.0010	0.0010	N/A
System Access Charge	100	100	N/A

[45] Details on administrative charges included in Chapter 3

Figure 13 shows the NPV for digester investments with herd sizes ranging from 500 to 4,000 lactating cows[46]. The "saw tooth" effect observed in the graph comes from the fact that investment costs only come in discreet units. In particular, larger components such as digester tanks and engine-generators are primarily responsible for the variation. Since this scenario is based upon current policies, it is also used as a baseline of comparison for other analyses in Section Three.

Clear economies of scale are present under the surplus sale and buy-all sell-all agreements with larger herd sizes exhibiting greater returns on investment. Despite the significant differences in business models between the surplus sale and buy-all sell-all agreements, their returns on investment over the range of herd sizes are extremely close. Buy-all sell-all agreements do not offset on-farm retail rate electricity, but instead receive compensation at the LMP which is less than half of the retail rate. In contrast, surplus sale agreements offset on-farm electricity use at the higher retail rate and only sell the excess to the utility at the LMP. While common intuition would suggest a surplus sale agreement to be the superior choice, standby charges paid under a surplus sale agreement reduce net revenues from electricity offsets and sales by 42% on average. This makes the NPV of both electricity purchase agreements almost equal.

This would suggest that a farmer may need to rely on other factors to make a decision between electricity purchase agreements. One factor may be the anticipation of higher retail electricity prices. As depicted in Figure 5 from the 1,000 cow example, higher retail

[46] The assumption was made that dry cows are kept in separate barns and do not contribute manure to the digester.

electricity prices make a surplus sale agreement more favorable. Another factor could be the involvement of a third party (e.g., energy project developer) who negotiates the electricity purchase agreements on behalf of the farm. For example, a third party[47] energy project developer may have a financial interest in the electricity sales and may not realize a benefit from offsetting the farm's electricity use. If this is the case, the farm may select a buy-all sell-all agreement.

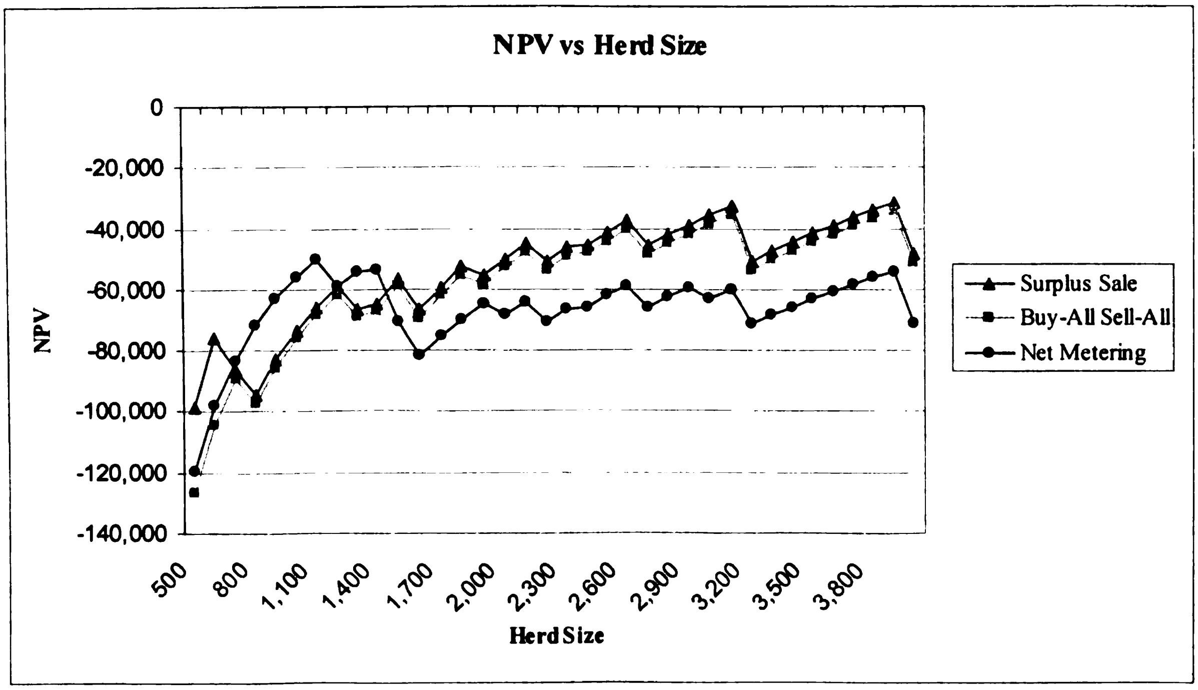
A net metering agreement shows higher returns for herd sizes ranging from 700 to 1,450 cows. As mentioned in the previous two sections, there are three main reasons for this result. First, under category three net metering, customers only pay standby charges if their engine-generator has a nameplate capacity greater than 150 kW. Second, they receive the power supply component of the utility bill (average of \$0.0612/kWh) for electricity produced. The other two agreements receive the LMP which is a lower value (average of \$0.0435/ kWh). Lastly, they do not pay administrative charges or system access charges. The other two agreements must pay both of these charges (see Table 23). Also note, however, that for herd sizes from 500-600 cows, surplus sale is clearly the preferable agreement. This is because these farms sizes would not be subject to standby charges under either a surplus sale agreement or net metering. Since a surplus sale agreement involves a larger engine-generator and increased electricity production, however, the return on investment is greater.

For herd sizes greater than 1,450 cows, however, net metering exhibits the lowest returns of the three agreements. This is due primarily to reduced electricity revenues from the

[47] Third party is defined as an entity that is not the farm or the utility company.

smaller engine-generator which is sized based upon the farm's average yearly electricity usage. At the same time, standby charges do not decrease since they are based upon peak on-farm energy usage measured in kilowatts (kW) and are unrelated to the average yearly electricity usage which is measured in kilowatt hours (kWh). Therefore, standby charges comprise a larger portion of the farm's electricity revenues under net metering. For example, at a herd size of 2,000 lactating cows, standby charges represent 60% of electricity revenues. For the same herd size under a surplus sale agreement, however, standby charges represent 42% of electricity revenues. As a result, the NPV of a 2,000 cow farm under net metering is 37% less than it would be with a surplus sale agreement.

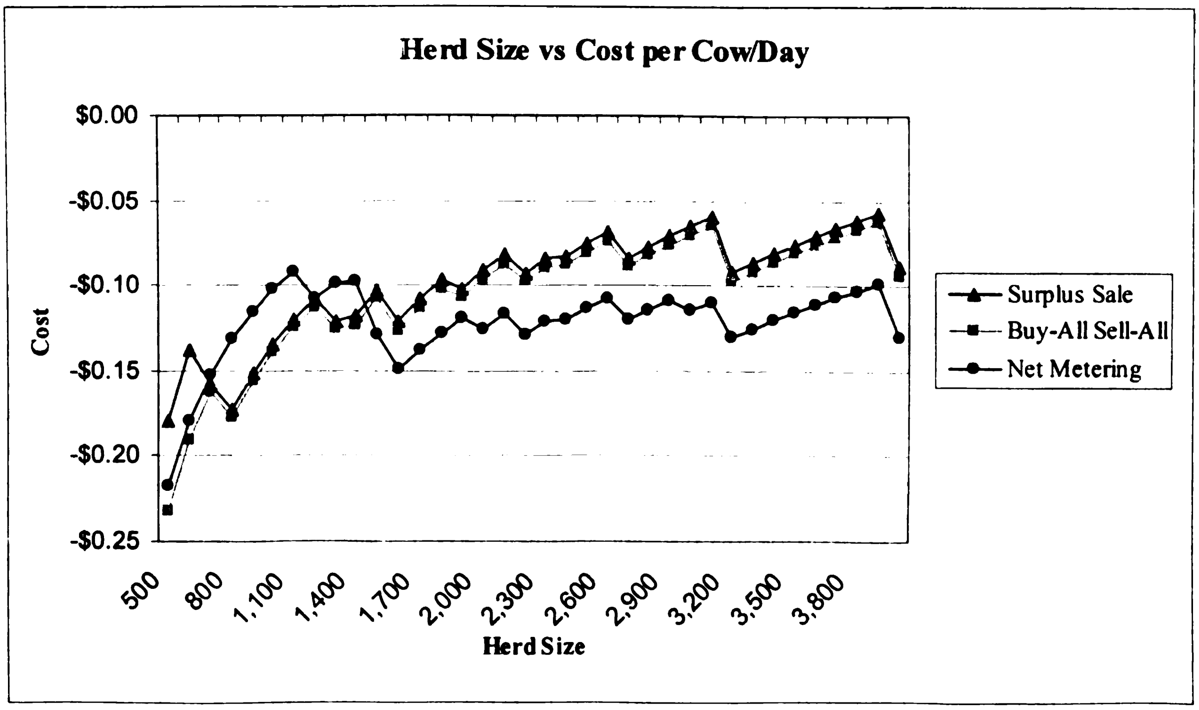
Figure 13. NPV Compared to Herd Sizes (500 to 4,000 cows)



4.4.1A Value of Odor Reduction

While Figure 13 shows negative NPV's for herd sizes ranging from 500 to 4,000 cows, a farm may still wish to install a digester for the odor reduction benefits that it provides. In order to quantify of the value of the digester's odor reducing benefits in more meaningful units, the NPV of the investment was broken down into a cost/cow per day with the results displayed in Figure 14. The assumption was that the difference between a negative net present value and zero represents the value of the odor to the farmer. Throughout the range of 500 to 4,000 cows, the value of odor control was valued at $0.10 per cow/day with a surplus sale agreement, $0.11 per cow/day with a buy-all sell-all agreement and $0.12 per cow/day with net metering. If examining only the larger dairies with herds over 2,000 cows, the cost/cow per day decreases to an average of $0.08 per cow/day due to economies of scale. When put in these terms, it would appear plausible that a farmer would still invest in an anaerobic digester despite a having a negative net present value.

Figure 14. The Cost per Cow/Day of a Digester Across a Range of Herd Sizes



4.4.2 Part II - Recommendations

This section brings together the results of the previous analyses in this chapter and uses that insight to make recommendations for energy policy which is more favorable to anaerobic digesters. The most recent purchase agreement option for digester owners is net metering which was finalized in July, 2009. In Figure 13 of this chapter, the model results showed that net metering only showed an advantage over the other existing agreements for herd sizes ranging from 500 to 1,450 cows. From a previous analysis in Section One, it was determined that this advantage was due in part to the higher threshold for standby charges (150 kW), the lack of administrative and system access charges and a higher value ($/kWh) for excess electricity produced by the system (power supply component of customer's electric bill). Since these elements were identified to be beneficial aspects of the new metering law, a series of sensitivity analyses were run to determine the effect of applying these specific policy elements to the other two agreements. An additional policy scenario was tested in which the current net metering policy for digesters was compared to "true" net metering which is currently only offered to small wind and solar technologies.

4.4.2A Standby Charges

In order to better understand how the standby charge threshold relates to herd size, Figure 15 shows the average yearly electricity production (kWh/hr) for a range of sizes.[48] For example, under a surplus sale agreement with a standby charge threshold of 100 kW, a 1,200 cow dairy would be subject to charges. This is because based upon the average

[48] As with section one, the average yearly electricity production is used to predict the appropriate nameplate capacity of the engine generator.

yearly electrical output potential of the 1,200 cow dairy, a digester would require an engine-generator nameplate capacity of approximately 195 kW. Since 195 kW is greater than 100 kW, the farm would be subject to standby charges if they wished to received service form the utility company when the digester engine-generator is down. The same size dairy with a net metering agreement and a threshold of 150 kW[49], however, would be limited to a nameplate capacity less than 125 kW. In this circumstance, the farm would not be subject to standby charges.

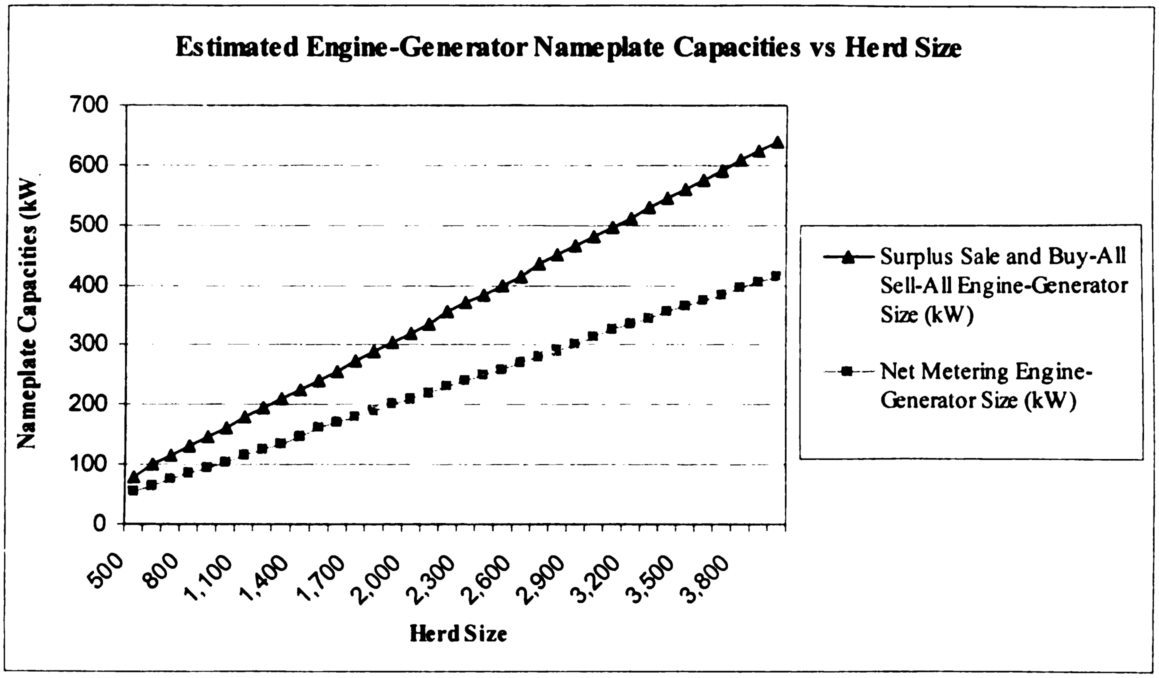
Figure 15 can also be used to measure the effect of either raising or lowering the standby charge threshold on digesters with a range of herd sizes. For example, consider an 800 cow farm with an estimated engine-generator size of 130 kW and a standby charge threshold of 100 kW. In this scenario, the farm would likely be subject to standby charges since the digester would require an engine-generator with a nameplate capacity greater than 100 kW. If a herd size of 500 cows was considered, then standby charges would not be required.[50]

The suggested nameplate capacities used here are considered close approximations, but in reality a farmer will be limited by the engine-generator offerings which are commercially available. In addition, a farm may wish to install a larger size generator than needed if planning to add additional feedstock or may decide on a smaller size to save costs and simply flare the extra biogas. The estimated engine-generator nameplate capacities in

[49] Category three net metering sets the standby charge threshold at 150 kW.
[50] A farm is not required to purchase standby service, but during generator downtime the utility is not obligated to provide service.

Figure 15 incorporate a 10% down time[51] and a 2% parasitic energy requirement and therefore are considered to be a realistic estimation of the appropriate size needed.

Figure 15. Estimated Engine-Generator Nameplate Capacities and Herd Size



<u>*4.4.2B "Net Metering Components"*</u>

<u>Scenario 1</u>

In Figure 16, all beneficial components of the net metering law (a standby charge threshold of 150 kW, produced electricity valued at power supply component of the customer's bill, and no administrative or system access charges) were applied to the other two electricity purchase agreements. Since this scenario does not include any changes to the current net metering policy, the results for the net metering agreement will not change from Figure 13. Table 25 summarizes the purchase agreement assumptions used in this analysis.

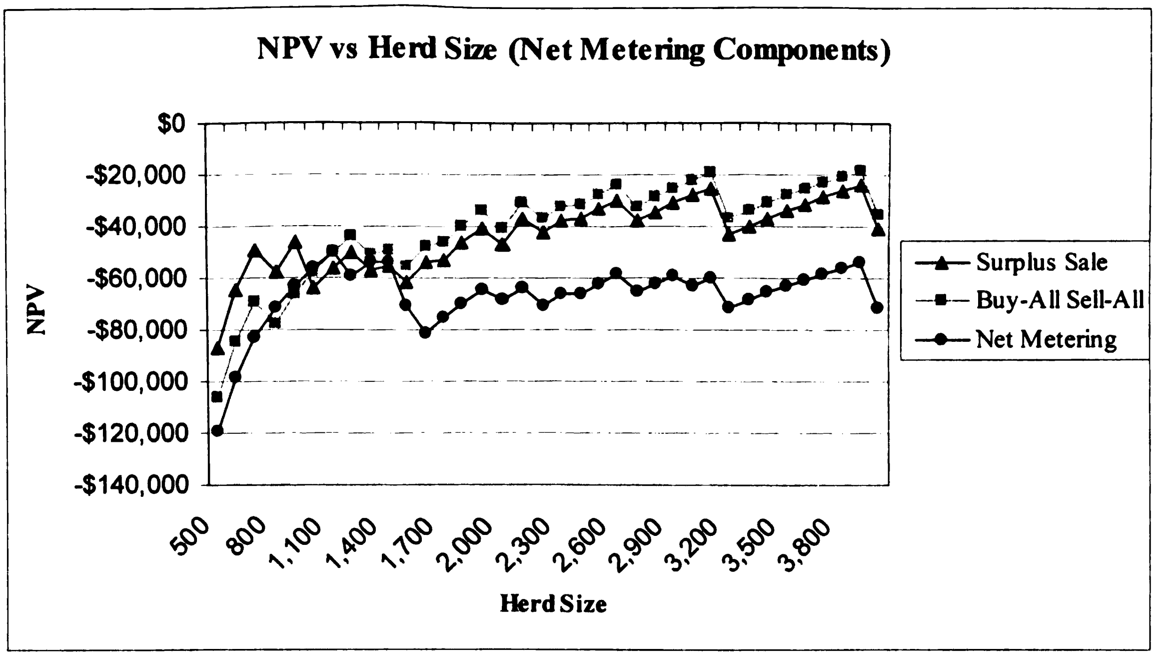
[51] This implies an operational online time assumption of 90%.

The model shows that the returns achieved through both the buy-all sell-all and surplus sales agreements are affected by herd size. For example, between a range of 500 to 950 cows, the surplus sale is clearly the preferred agreement. In this range, the beneficial components of net metering increases the NPV of the digester by 30.5% with a surplus sale agreement compared to 20.0% with a buy-all sell-all agreement. This is because a farm with a herd size under 950 cows would not be subject to standby charges. The buy-all sell-all agreement does not pay standby charges under any circumstance, since it does not involve offsetting on-farm electricity use. For herd sizes over 950 cows, however, a buy-all sell-all agreement becomes the preferred agreement. In this range, the digester NPV increases by an average of 34% compared to 18% with a surplus sale agreement. These values represent increases from the current policy depicted in Figure 13. Despite the increase in returns from the proposed scenario in Figure 16 "NPV vs Herd Size (Net Metering Components)", the digester does not achieve a positive NPV for the herd sizes tested.

Table 25. Scenario 1 Policy Summary

Policy Summary	Surplus Sale	Buy-All Sell-All	Net Metering
Standby Charge Threshold (kW)	150	150	150
Average Value of Excess Electricity ($/kWh)	0.0612	0.0612	0.0612
Administrative Charges ($/kWh)	N/A	N/A	N/A
System Access Charge	N/A	N/A	N/A

Figure 16. NPV vs Herd Size Using Net Metering Components

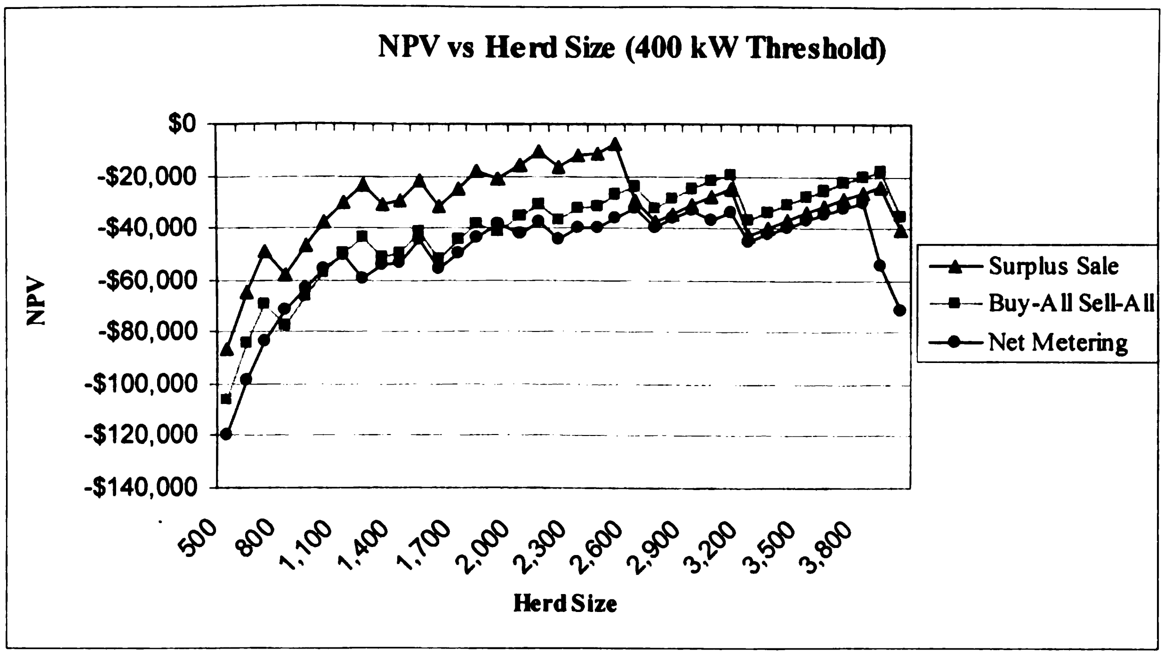


The next two scenarios maintain the same assumptions from Table 25, but increase the standby charge threshold to 400 kW (Figure 17) and 800 kW (Figure 18). As discussed in Part One (Figure 15), increasing the standby charge threshold essentially exempts larger farms from paying charges for standby service from the utility company.

<u>Scenario 2</u>

In Figure 17, the standby charge threshold was raised from 150 kW to 400 kW. Under this scenario, the buy-all sell-all agreement shows the same results as in Figure 16 and is unaffected by the threshold increase. With the surplus sale agreement, the only difference pertains to the range of herd sizes that are able to benefit from not paying standby charges. In this scenario, herd sizes ranging from 500 to 2,500 would benefit from this sort of policy change compared to only up to 950 in Figure 16. The NPV increases by 56% with a surplus sale agreement and 28% with a buy-all sell-all agreement on average for herd sizes ranging from 500 to 2,500 cows. Between this range, the surplus sale is clearly the preferred purchase agreement. By not being subject to standby charges, the farm is able to reduce expenses and increase cash flows.

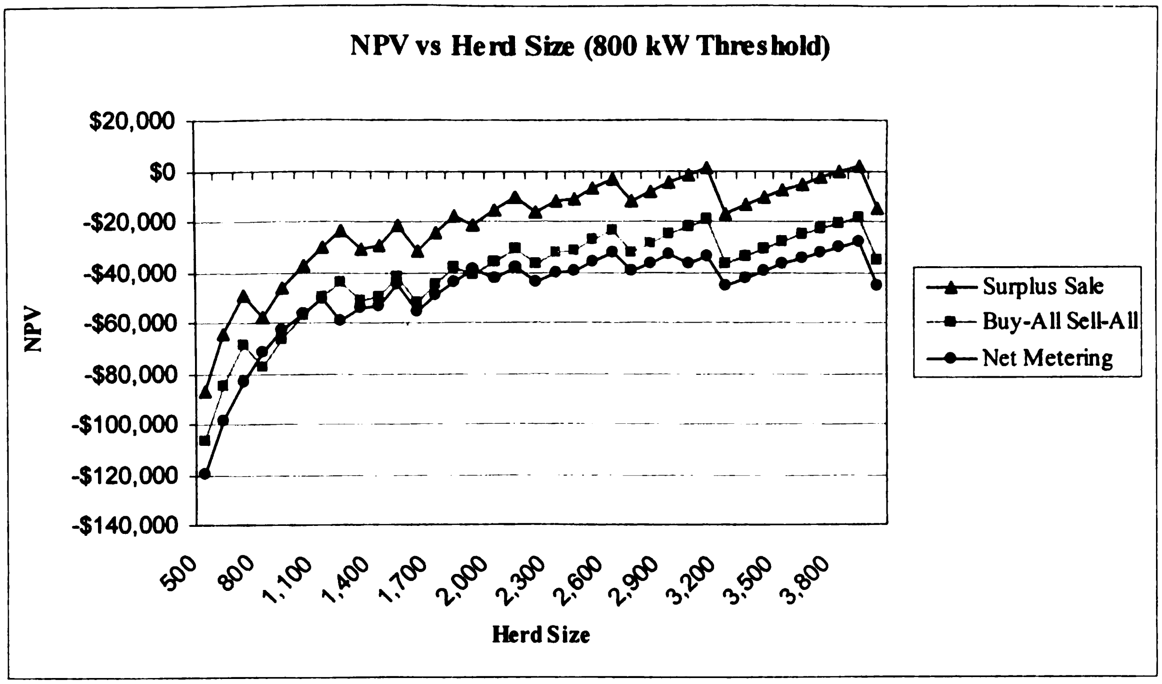
Figure 17. NPV vs Herd Size with Standby Charge Threshold of 400 kW



For herd sizes ranging from 2,600 to 4,000 cows, the NPV remains unchanged from the scenario in Figure 16 under a surplus sale agreement. In this range, a buy-all sell-all option becomes the preferred purchase agreement. For net metering, however, raising the threshold to 400 kW essentially eliminates standby charges for almost all herd sizes tested. Only dairies with a herd greater than 3,900 would still be subject to the charges. When compared to the current policy (Figure 13), the NPV increases by an average of 28% across herd sizes ranging from 500 to 3,800 cows. Despite the increase, however, it is the least favorable of the three agreements.

Scenario 3

Figure 18. NPV vs. Herd Size with Increased Standby Charge Threshold of 800 kW

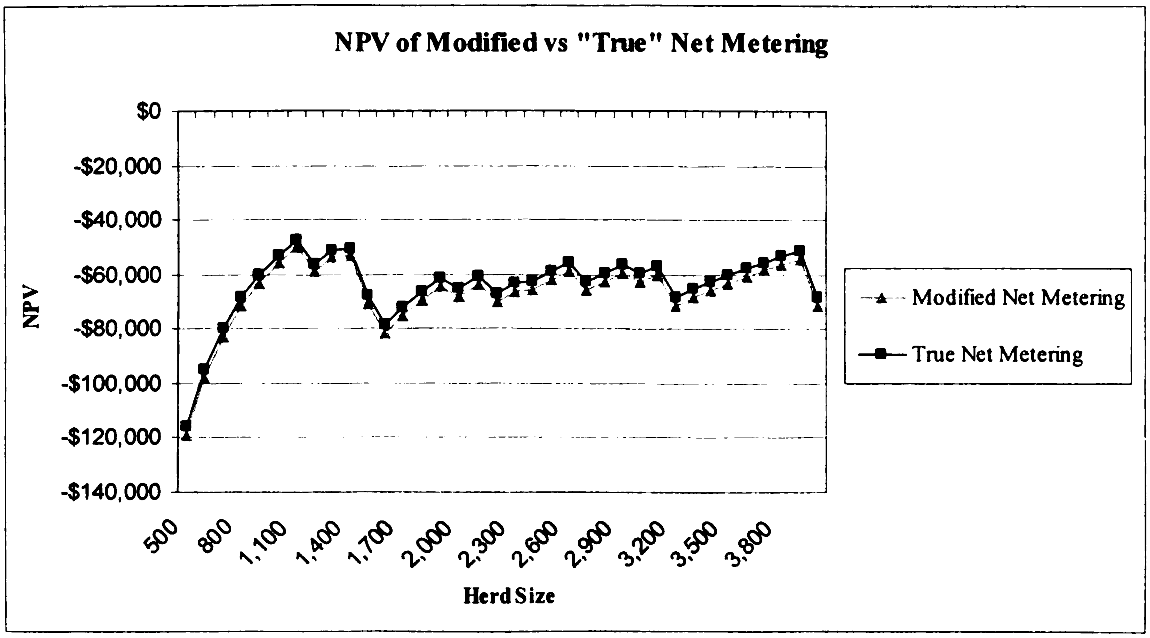


In Figure 18, the higher standby charge threshold essentially eliminates the charges for the entire range of herd sizes. In addition, for farms with more than 2,600 cows, the returns start to become positive under a surplus sale agreement. On average, the NPV of the surplus sale agreement increases by 68% across the herd sizes tested. This scenario points out the fact that a digester investment could be a marginally profitable investment for surplus sale agreements with an increase in the standby charge threshold from 100 kW to 800 kW.

4.4.2C Modified Net Metering vs. "True" Net Metering

The final scenario in this chapter addresses the question of whether "true" net metering would be beneficial for anaerobic digesters. "True" net metering means that a customer receives payment for their electricity at the same price at which they purchase from the utility company. Currently, only small wind and solar systems with nameplate capacities less than or equal to 20 kW can benefit from this policy. In Figure 19, all assumptions from Tables 22 and 23 are the same expect for the value of the electricity produced, which was assumed to be the same as the retail value ($0.0988/ kWh).

Figure 19. "Modified" vs "True" Net Metering Across a Range of Herd Sizes



The results show that "true" net metering would not produce a significant increase in the return on investment of a digester system. This is because the smaller sized generator produces less excess electricity to be credited at the higher price. Therefore, an increase in the price credited has little effect on the overall returns from the system. This result suggests that pursuing "true" net metering for digester systems would not be worthwhile.

Chapter 5: Conclusions

Anaerobic Digestion is receiving a great deal of attention as a viable alternative in supporting residuals management for livestock operations. In contrast to conventional liquid and slurry management systems, anaerobic digesters provide multiple environmental benefits such as odor control, improved air and water quality, improved nutrient management flexibility and the opportunity to capture biogas for heat and electricity production. (U.S. EPA, 2002). "Without the environmental benefits provided by AD technology, some farmers might be forced out of livestock production and a digester is sometimes the only technology that allows growth in the livestock production business" (Lusk, 1998, p.1-2).

The digester system is a process which includes collection and handling, anaerobic digestion, by-product recovery and effluent use, biogas recovery and biogas use. There is significant variability in digesters from one farm to another and it is difficult to make generalizations and comparisons. Proper maintenance and monitoring of equipment and the microbiological conditions inside the tank itself are crucial to the success of the digester.

Although energy production alone has not been cited as the primary motivation for the installation of anaerobic digesters, state polices on distributed power pricing can greatly affect the economic viability of digesters (Lazarus, 2008). In order to analysis the situation, a multi-purpose model was developed with the capability to research the economic effects of the three electricity purchase agreements available to digester owners in Michigan. In addition to a research tool, the model can be used for outreach purposes to examine specific systems and assist engineers in making design decisions. In Chapter 4, a series of analyses were performed to demonstrate its use and flexibility. In order to effectively summarize the key findings of this research, conclusions have been broken down by section.

Section One

In section one, the results suggest that the business model of each electricity purchase agreement will determine its response to price increases. For example, although all three agreements show an increased return on investment from higher retail electricity prices, a surplus sale agreement benefits the most. This is because it is based primarily upon offsetting on-farm electricity at the retail rate and only selling the excess production at the locational marginal price. In addition, future energy legislation such as feed-in-tariffs would have the most significant effect on a buy-all sell-all agreement although lesser benefits were also observed with the other two agreements.

With the 1,000 cow example, net metering was shown to be the most preferable agreement under the analyses tested given the prices assumed in the model. This is due to the fact that the farm would not pay standby, administrative or system access charges based upon the engine-generator nameplate capacity required from predicted average yearly electricity production. As the prices were increased, however, net metering was shown to be an inferior agreement compared to the other two options.

Overall, the breakeven prices calculated by the model appear to be feasible given the trend for higher electricity prices, pending cap and trade legislation and a demand for utility companies to comply with Renewable Portfolio Standards. Furthermore, it is likely that increases in prices will occur simultaneously which would lower the breakeven prices calculated in the model.

Section Two

High levels of VS loss and low TS concentrations both lead to digester heating deficits and decreased electricity production. According to the model, however, low total solids concentrations have a more significant impact of the NPV of the system. This is primarily due to the fact that lower TS concentrations increase the capital costs of the digester system with higher levels of water in the digester influent requiring larger digester tanks and more heat. With net metering, the smaller 105 kW engine-generator made the digester system less sensitive to these changes. This is because the extra biogas allows the engine generator to run at full capacity despite decreases in biogas production.

In terms of online time, it was shown to have a linear relationship with average yearly electricity production. For example, every 1% increase in online time increased the NPV by $8,555 with a surplus sale agreement. In general, the information from this section will allow an engineer to more effectively predict digester performance and quantify the effects of engineering design decisions.

Section Three

Over a range of heard sizes, a digester investment does not achieve a positive NPV under the current policies and assumptions. When the costs are considered on a per cow/day basis, however, the costs appear to be low enough to justify the investment for certain farmers. It is assumed that this cost represents the value of odor reduction to the farm owner.

When considering policy recommendations, the model suggests that applying the beneficial components of net metering to the other two purchase agreements would not be sufficient to produce a positive after-tax NPV. Subsequent scenarios, however, show an increasing benefit to larger dairy farms (with surplus sale and net metering agreements) as the standby charge threshold is increased to 400 kW and 800 kW. At a threshold of 800 kW, a digester system begins to show positive returns on investment. This suggests that a change in the standby charge policy of the major utility company examined would produce significant results for digester owners under a surplus sale or net metering agreements.

An additional policy recommendation would be to pursue "true" net metering for digester systems which currently operate under "modified" net metering arrangements. The model shows, however, that this effort would not be worthwhile as only slight increases in NPV are achieved through this policy change.

5.1 Areas for Future Research

Since multiple levels of detail are built into this model, future analysis could center on further exploring tradeoffs between engineering design decisions, energy uses and additional feedstocks. To achieve this purpose, new components to the model could also be added. For example, programming the model to predict biogas production outside of the target temperature range would be a valuable tool for engineers. In terms of financing, new mechanisms could be explored (e.g., federal investment tax credits) and the model could be used to evaluate their effect on digester systems.

Another area of research would be to determine the optimal price of retail electricity, carbon credits, RECs, etc. when considered in a single scenario. The current analysis examines each element in isolation, when in reality price changes are often connected. This would give a more accurate evaluation of the breakeven prices required for a digester system.

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