

Mid-Atlantic Propane Assisted Biodigester: Technical and Economic Feasibility Assessment



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Executive Summary

Environmental studies have shown that there are significant water quality issues in the Chesapeake Bay drainage basin, mainly related to phosphorous and nitrogen pollution. Biodigesters (also referred to as anaerobic digesters) are an increasingly popular option for farms to address their manure management issues. When this project was conceived, it was believed that the anaerobic digestion process also reduced the nutrient concentrations, especially phosphorous. Unfortunately, this is not true; the nutrient concentrations are only marginally affected in the digester. Farms that need to reduce their phosphorous concentrations must install a separate processing step after the material has left the digester system.

Digester systems use manure or other biological material, such as food processing wastes, as a feedstock. Bacteria present in the manure break the material down and produce methane (60-70%), carbon dioxide (30-40%), and other trace gases (mainly hydrogen sulfide). This gas mixture is referred to as biogas and has a lower energy content than pipeline natural gas due to the high carbon dioxide content. The biogas is fed into a generator set that is designed to operate on this low-energy fuel. As a result of the lower energy, the output power operating on biogas is lower than on natural gas. The biogas fueled generator is beneficial to the farmer because the generator produces electricity to offset the farm's electric bill, which can be a significant expense. In many states, excess power is sold back to the grid through a net metering agreement available to small generators of renewable power such as biogas. The net meter power purchase rates vary by state and can be very low (e.g. \$0.0275/kWh in Pennsylvania) or rather reasonable (e.g. \$0.085/kWh in New York).

One goal of the project was to determine the effect that installing a digester will have on a farm's propane usage. An extensive literature review was done as well as phone and on-site interviews with farms with digesters to understand how farms operate, the problems, issues, and performance of the digesters, and the impact that installing the digester had on their propane usage. Due to the thermodynamic efficiency of a spark-ignited generator engine, a large amount (~75-80%) of waste heat energy is rejected from the engine. Some of this energy can be captured using cooling water. One use for this waste heat energy is to maintain the digester at its optimum operating temperature; this was done by all of the farms. The excess waste heat energy can potentially be used for any process that requires heat such as space heating, water heating, and other applications where propane is currently used. Unfortunately, there was no consistent pattern to how effectively the farms utilized this waste heat energy. The layout and logistics of each farm determine how to best use the waste heat. In many cases, the waste heat was used to preheat boiler water or for radiant floor heating. However, other buildings where the heat was needed were often too far from the digester to be worthwhile. In other cases, the heat could be used but the farm has not yet taken advantage of it. As a result, the overall impact the digester system will have on propane use cannot be quantified.

Augmenting the generator set to operate on 100% or any lower percentage blend of propane was proposed to allow the farm to be able to optimize the performance and output of the digester to improve efficiency and increase generated income. The concept of a dual-fuel (biogas-propane) system was discussed with the major biogas genset manufacturers (Waukesha Engine, Cummins Power Systems, Caterpillar, and GE Jenbacher) to determine the technical viability and additional cost for this type of system. GE Jenbacher was the only company to offer a system that can blend biogas and propane. Their system is able to operate on any blend from 100% biogas to 100% propane. Unfortunately, the smallest generator is approximately 200kW, which is significantly higher and more expensive than the generators used in farm based digester systems, so was not considered further. The three remaining manufacturers do not offer a dual-fuel system for biogas and propane; however, they offer other dual-fuel options (e.g. biogas-natural gas, natural gas-propane). They said that it would be technically feasible, but that, due to the large difference in energy content between biogas and propane, the engine would have to be detuned and would produce the same power when operating on propane as when operating on biogas. Several farms mentioned they have gensets that can operate on either 100% biogas or 100% propane, but not a mixture of the two. The farms were asked how the fuel system can handle this since the manufacturers apparently had never heard of it before. The digester engines are originally either natural gas- or propane-fueled, not specially designed biogas engines. A fuel switching valve is installed ahead of the engine that handles the switch from biogas to propane, and vice versa. As a result, the engine produces more power when operating on propane than on biogas, a result of the higher fuel energy content.

One proposed use for propane augmentation was to use a low-blend of propane to stabilize the power production. Unfortunately, the net metering accounting is done based on an annual basis. So it is not important that the generator produce a constant power, only that there is a net positive power production in the year. In addition, biogas is essentially a free fuel for the farm, so using a fuel such as propane that is an additional cost would not be logical. A cost model was developed to determine the economic viability of this case and others mentioned later. The model verified that this is not a good application.

Using propane in either the existing generator, or an additional generator, to produce peaking power for the utility was also investigated. Utilities purchase peaking power in the summertime when they need additional capacity to meet the high demands, typically air-conditioning loads. This was estimated to account for roughly 5% of the annual hours. In the past the rates for peaking power were frequently as high as \$0.75/kWh - \$1/kWh range. IN fact, rates of \$6/kWh were paid in New England in 2000. Several Mid-Atlantic region electric utilities were contacted to discuss the possibility of using digesters as a distributed peak power production reserve. In almost all cases, the utilities did not reply. Discussions with the farms that are utility customers said that this was not unexpected. One farm mentioned that they had gone back and forth with their electric utility for nine months to get a question resolved. Others said that it took a very long time to get the approvals for connecting their system. In

general, the farmers' impressions were that the amount of power being produced by the gensets is almost infinitesimal in comparison to the total power market so the utilities do not want to be bothered. As a result, detailed information verifying the figures on annual hours and peak power purchase rates were not able to be determined. One utility, New York State Electric & Gas Corporation (NYSEG) and two state Public Utility Commissions (Pennsylvania and Delaware) were contacted and agreed with this assessment. These entities understood the peaking power production concept, but felt that it was flawed because the farms are not located where the peak demands occur (rural vs. urban). They also felt that the small amount of power that could be uploaded to the grid would be too small for the utility to likely be willing to deal with. Another issue is that utilities are required to purchase renewable energy, such as from solar, wind, and biomass derived gases (such as biogas), but they are not required to purchase peak power regardless of the fuel. Thus, farms would have to broker a deal with the utility to purchase the peak power from their farm. NYSEG said that, since their company provides electricity and natural gas, they would be unlikely to agree to this. If, however, a peaking agreement was granted, the farm would have to be able to deliver a predetermined power output when called upon. Since the power from biogas fuel would fluctuate with gas production, propane could be used to provide a definite constant power level. Also, the output power on propane is higher than biogas, so more energy could be sold at peak rates.

Several digester augmentation concepts for using propane to produce peaking power were proposed and modeled. The results show promise for the practical application of this concept. The most basic case was one in which propane was used for 5% of the year in the existing generator. The increased propane sales from this option were 9,418 gallons per year. Several other cases involving the installation of a second generator with varying combinations of biogas and/or propane fueling were investigated. Using the generators to continually produce power using biogas until they are needed for propane peaking provides the best payback. Several cases operate on propane for the same proportion of time, thus resulted in equivalent propane sales (9,418 gallons per year). One option used two generators for peaking power production, resulted in double the propane usage of 18,836 additional gallons per year.

In most of the cases where a second generator was added, there was not a good economic case for using propane for peaking power unless the peak power rate was above \$0.25/kWh. Using the additional generator to produce net metered power using biogas is a significant benefit since the farm is able to use the generator year round, and even though the rate is much lower, it has a positive impact. The profitability of this additional power is much higher in states like New York where the utilities pay a higher rate for biogas derived power. In states where the net meter excess power purchase rate is lower, such as Pennsylvania, the case is a tougher sell because the capital cost of the additional generator must be paid back mostly from peak power sales. Utilities in Maryland do not pay for excess power, so the incremental cost would be paid back from peak power sales alone.

The ultimate viability of this concept lies with the electric utilities and whether they are willing to allow peaking from the digester farms and, if so, what peak power rate they would offer. All of the farms that were interviewed were interested in participating in a Phase II demonstration if the concept was economically viable.

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Section 1: Introduction

Anaerobic digesters (also referred to as biodigesters) are increasingly being used on farms for both environmental and economic reasons. The dairy industry has especially seen an increase in the use of this technology to reduce farm animal waste run-off and to utilize its energy potential for producing electrical power and heat. In addition to the biogas generated from the animal waste that can be used as fuel, the digester also produces a stream of liquids and solids. The liquids, which are a good source of nitrogen, can be used as a fertilizer. The solids, which contain high concentrations of phosphorous, can be processed into a variety of products, such as garden mulch or substrate for growing mushrooms. Disposing of the phosphorous in this manner will substantially reduce phosphorous leached into local waterways and watersheds such as the Chesapeake Bay.

While the digester biogas will be the primary fuel source for cogenerating electricity and thermal energy throughout much of the year, propane could be used as the primary fuel during peak electric demand periods to insure a reliable supply of electricity as well as for augmentation when the biodigester does not have sufficient gas production. This can occur during periods of cold weather and when the biodigester is not adequately charged with adequate waste materials. The propane assisted biodigester concept is easily integrated with such current farm uses of propane as facility heating and vehicle motor fuel, and the concept supports the propane industry's rural fuel market focus on the "Propane-Powered Farm." Further, electrical power generated by the use of the propane/biogas fed power generators that is not used by the farm can be sold to the grid at high demand prices, resulting in enhanced farm economics. The electric utility serving the host farm may also benefit from the added stabilization to the power supply grid and from deferring or eliminating costly investments in transmission/distribution system upgrades into rural or low population density areas.

This project is important for the propane industry in that it may lay the ground work for large scale implementation of propane-assisted biodigesters within the dairy farming areas that form the Chesapeake Bay watershed and similar watershed areas. The project work presented in this report describes the first of a two-part effort. Phase I consisted of a technical and economic feasibility study of propane fuel-assistance for agricultural biodigesters to provide facility electrical power and excess electrical power back to the grid. The goal of this first phase was to develop the information necessary to support the second phase, a commercial scale hybrid-power, distributed energy demonstration project implementing this concept. Conclusions and recommendations from Phase I of the project are provided, including the justification for performing Phase II.

This report is organized as follows. Section 2 contains this introduction and background. Section 3 presents the farm demographics for the Mid-Atlantic region. In Section 4, propane-assisted biodigester designs are discussed and evaluated. Section 5 lists and discusses the

interconnection and utility issues relevant to the siting of the biodigester technology. An economic assessment of the propane-assisted biodigester concept for farm applications is provided in Section 6. Section 7 contains a discussion of the potential level of support and interest from the farming and electric utility industries. Finally, the conclusions and recommendations for the technology are presented in Section 8, along with recommendations for a follow-on field demonstration of the technology in a Mid-Atlantic regional dairy farm.

Section 2: Chesapeake Bay Water Quality Issues

Section 2.1: Chesapeake Bay Overview

The Chesapeake Bay was formed about 12,000 years ago as glaciers melted and flooded the Susquehanna River valley. It is North America's largest estuary and the third largest in the world. The Chesapeake Bay is approximately 200 miles long and runs north-south from the mouth of the Susquehanna River to the Atlantic Ocean. The bay's watershed covers 64,000 square miles and has 11,600 miles of tidal shoreline, including tidal wetlands and islands, and encompasses parts of six states: Delaware, Maryland, New York, Pennsylvania, Virginia, and West Virginia, as well as Washington D.C. The watershed includes more than 100,000 streams, creeks, and rivers, including 150 major rivers. Bay tributaries can be reached in less than 15 minutes from nearly everywhere in the watershed. This is a very populated area, with approximately 16 million people living in the watershed; about 10 million people live along or near its shores¹. The Bay supports 3,600 species of plant and animal life, including more than 300 fish species and 2,700 plant types. More than 500 million pounds of seafood are harvested from the Bay every year¹.

Section 2.2: Pollution Problem

The most significant pollution problem for the Chesapeake Bay and its tidal rivers comes from excess nitrogen and phosphorus. The results of the pollution have landed both the bay and its rivers on the Clean Water Act's list of impaired waters². Nitrogen and phosphorus are the main bay pollutants. They enter the Bay from sewage treatment plant effluent, agricultural runoff and other sources. The EPA's Chesapeake Bay Program considers nitrogen to be the biggest threat to the Bay's health. Nitrogen is critical for crop growth, and is a major component in fertilizer. However, excess nitrogen not used by the plants ultimately finds its way to the water supply. Farmers are increasingly using nutrient management techniques to minimize the nitrogen runoff, but this is not enough to fix the problem.

Excess phosphorus is another major cause of water pollution. Phosphorus is another important plant nutrient, and, as with nitrogen, it accumulates in soil when it is applied at rates beyond crop needs. The Chesapeake Bay Foundation commented on this fact, stating "for most of the last 20 years, University agronomists and others encouraged farmers to apply manure to the land based on crop nitrogen needs. Manure has far more phosphorus than nitrogen relative to crop needs, so manure application has resulted in an over-application of phosphorus. Research now shows that phosphorus can be lost in runoff when levels in soil are very high, even when controlling erosion. A healthy condition would be for soil phosphorus levels to be no higher than optimum levels for crop use (as determined by soil tests), and for counties with historically high animal populations to achieve steady reductions in soil

¹ Chesapeake Bay Foundation – Watershed Overview, http://www.cbf.org/site/PageServer?pagename=exp_sub_watershed_overview.

² Chesapeake Bay Foundation - State of Agriculture 2005 Report, <http://www.cbf.org/site/DocServer/StateOfAg.pdf?docID=4343>.

phosphorus levels through nutrient management and alternative uses of manure. The Bay states have just begun requiring consideration of phosphorus levels in manure application, so there is reason to hope this indicator will improve. The greatest surpluses occur in the major animal production areas of the Delmarva Peninsula, the Shenandoah Valley, and Lancaster County, PA².

Nitrogen and phosphorus pollution act as nutrients that cause population explosions of microscopic plants called phytoplankton, a type of algae. These large populations are called "blooms" and typically occur in the Spring. The algae blooms destroy habitat and kill fish by affecting the dissolved oxygen levels in two ways. First, the blooms block sunlight to underwater grasses, which reduces dissolved oxygen levels³. Plants give off oxygen when they grow, but the slowed or halted growth from lack of sunlight reduces the oxygen input into the water. Low dissolved oxygen (DO) levels, called hypoxia, can impair growth and reproduction and stress living resources, making them vulnerable to disease. Water with no oxygen, called anoxic, will kill most aquatic animals⁴. Secondly, as algae die they sink to the bottom in the deep-water areas of the Bay, and the decomposition process removes oxygen from the water. This causes hundreds of square miles of bottom waters to become hypoxic or anoxic during much of the summer. The effect is known as a "dead zone" since there is too little oxygen to support a healthy ecosystem⁴.

Section 2.3: What is Being Done

The Chesapeake Bay Agreement is a voluntary pledge to restore the Bay's health signed by the governors of Maryland, Virginia, and Pennsylvania, as well as the administrator of the Environmental Protection Agency and the mayor of Washington, D.C. According to the Chesapeake Bay Foundation 2006 *State of the Bay Report*, the Bay's health currently rates a 29 out of 100. At its worst in the early 1980s, the score would have been a 23; a "saved Bay" would score a 70⁵. Farmers have improved their management of phosphorus, but high concentrations of livestock and poultry in some regions overwhelm the land base with excess amounts of manure, making phosphorus pollution control still insufficient².

Section 2.4: What Still Needs to be Done

According to the Chesapeake Bay Foundation, the best way to address the low dissolved oxygen problems in the Bay is to reduce nitrogen pollution from farmland and urban runoff, from airborne sources such as vehicles and power plants, and from sewage treatment plants. In general, over the next seven years, nitrogen pollution from sewage treatment plants, urban

³ Chesapeake Bay Foundation – Sewage Overview,
http://www.cbf.org/site/PageServer?pagename=exp_sub_state_sewage.

⁴ Chesapeake Bay Foundation – Chesapeake Bay Dead Zones,
http://www.cbf.org/site/DocServer/DeadZoneFactSheet_May06.pdf?docID=5583.

⁵ Chesapeake Bay Foundation - State of the Bay 2006 Report,
http://www.cbf.org/site/DocServer/SOTB_2006.pdf?docID=6743.

runoff and agricultural sources will have to be reduced by about twice the reductions accomplished in the first twenty years. A recent analysis of costs to implement the Chesapeake 2000 Agreement goals concluded that the region would need to invest between \$1-2 billion per year to achieve the agreement's goals⁴. The Foundation is an advocate for conservation programs and for technical and financial assistance to farmers to establish riparian buffer zones (vegetation at the land/flowing water interface that impact soil erosion and aquatic ecosystems), cover crops, rotational grazing, and other conservation practices to reduce nitrogen and phosphorus pollution to our rivers and streams. They have determined that these types of agricultural practices are the most cost-effective way to reduce nitrogen and phosphorus pollution to the Bay. In fact, scientists estimate that we could achieve almost two-thirds of the nitrogen and phosphorus reductions necessary to restore the Chesapeake Bay, at only 13% of the total cost of Bay restoration, by implementing these types of agricultural practices⁶. The Foundation believes that new technologies to reduce nitrogen and phosphorus pollution must be invested in along with the development of alternative uses of excess animal manure².

⁶ Chesapeake Bay Foundation Website – Agriculture Page,
http://www.cbf.org/site/PageServer?pagename=exp_sub_state_agriculture.

Section 3: Mid-Atlantic Farm Demographics

Section 3.1: Mid-Atlantic Farm Inventory

The Mid-Atlantic States include Delaware, Maryland, Pennsylvania, New York, Virginia, and West Virginia. All of these states include at least a portion of the Chesapeake Bay watershed. The included counties were determined from the Chesapeake Bay Program website⁷. All of the counties in Delaware and Maryland are in the basin. In Pennsylvania, 39 of 62 (63%) counties are included. In New York, 19 of 67 (28%) counties are included. In Virginia, 61 of 95 (64%) counties are included. In West Virginia, 9 of 54 (17%) counties are included. Figure 1 shows the region and the vast area the watershed encompasses.

Data from the most recent U.S. Department of Agriculture (USDA) Census of Agriculture (2002) was gathered to provide detailed information on dairy farms⁸. The data is available by county, herd type (e.g. cattle, milk cow, etc.), number of farms with a given herd size range (e.g. farms between 1-99 cows, farms between 100-199 cows, etc.). The USDA tracks data on a county level both to protect proprietary information on individual farms and because more detailed information would significantly increase the workload. The demographic data was imported into the ArcGIS software framework to show the relevant farm information; distributions are shown by number of farms and by density of cows (Figures 2-5). These figures reinforce the previous section's conclusions regarding areas with the largest water quality problems are related to phosphorous runoff from dairy farms. Many counties in New York State, central Pennsylvania, and western Maryland have high dairy cow populations. Lancaster County, Pennsylvania has both the highest number of cows and the highest cow density. It can be concluded that these are likely areas where large amounts of phosphorous can enter the Bay's water supply.

⁷ Chesapeake Bay Program Website, <http://www.chesapeakebay.net>.

⁸ USDA 2002 Census of Agriculture, http://www.nass.usda.gov/Census_of_Agriculture/index.asp.

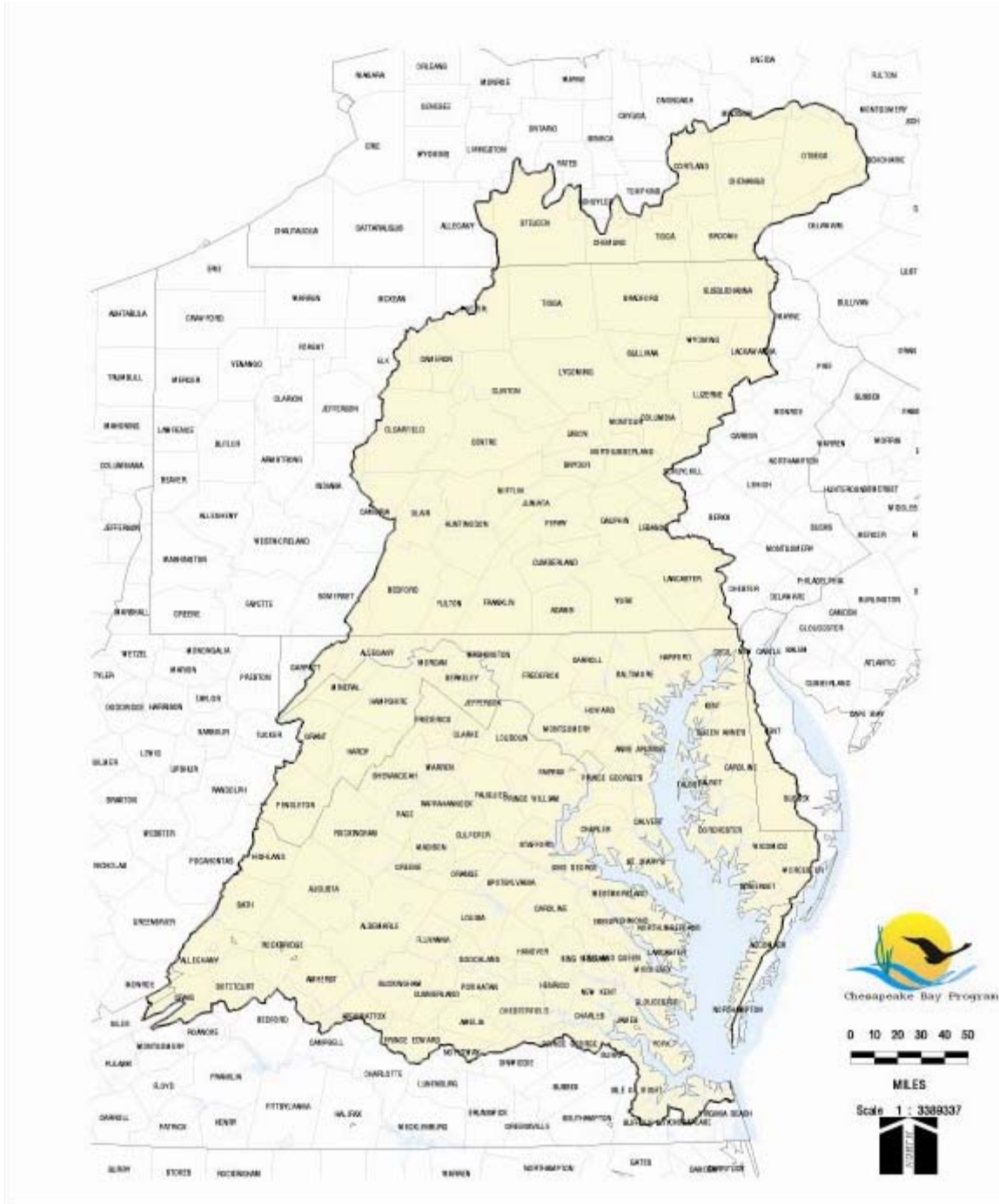


Figure 1: States and Counties Included in the Chesapeake Bay Watershed
(<http://www.chesapeakebay.net>)

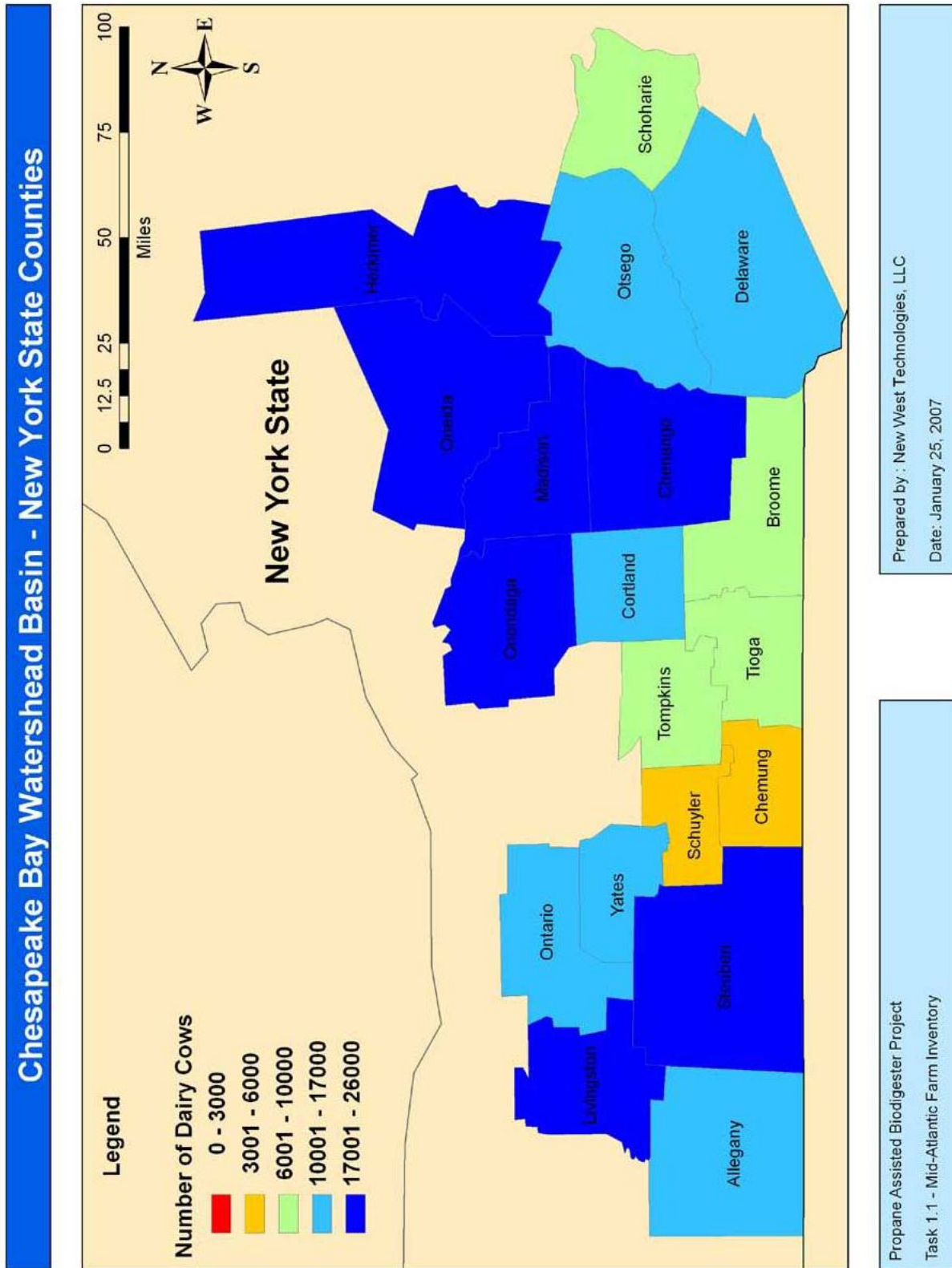


Figure 3: Dairy Cow Distribution (NY)

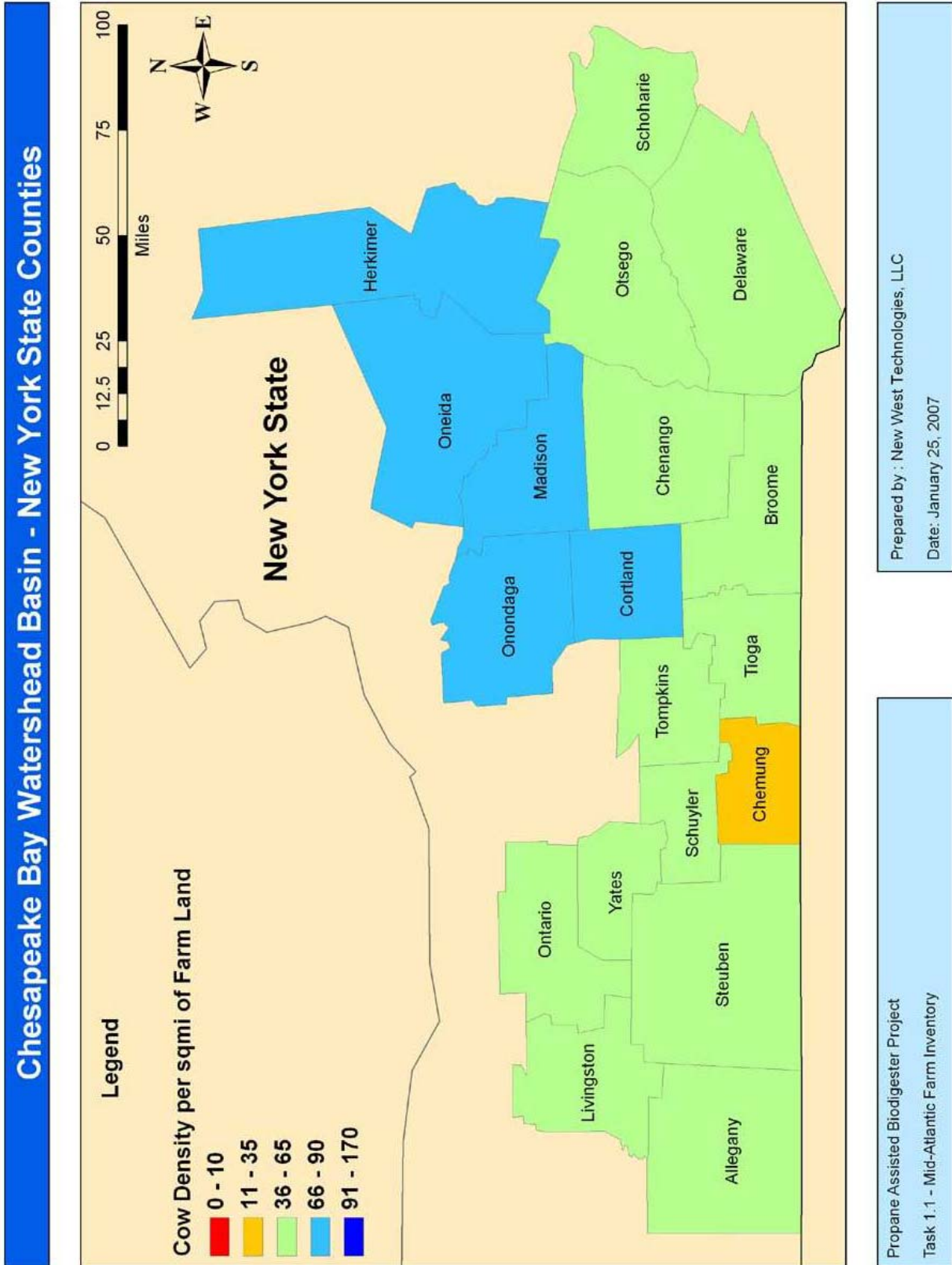


Figure 5: Dairy Cow Density (NY)

Section 3.2: Propane Availability in the Chesapeake Bay Watershed

Propane availability in the Mid-Atlantic region was investigated to ensure sufficient fuel availability to enable the potential widespread application of propane assisted biodigesters. Information was collected on a county level as in the farm inventory section. The goal was to show that propane was readily available in counties in the Chesapeake Bay Drainage Basin, not to determine a comprehensive list of propane suppliers in each county.

Each state's propane association was contacted to discuss the project to explain the goals and how it could potentially impact sales for their members. Several state associations provided information on the number and names of member companies. Several state propane organizations were not willing to share information on their members, including the counties in which they operate.

The major propane suppliers for the mid-Atlantic region include: AmeriGas, TriGas Oil, FerrellGas, United Propane, and Suburban Propane. Their company websites' location tools were used to augment the propane availability survey. Suburban Propane was contacted directly since they are a large company with locations in nearly every county in the Mid-Atlantic. It was assumed that a company would supply fuel to farms in that county, but not outside the county borders. This is likely a poor assumption, but was done to simplify the survey so each company did not need to be called to verify their service area coverage.

All of the counties that are in the watershed in Pennsylvania (39), Delaware (3), Maryland (23), New York (19), and Virginia (61) have propane available. Seven of the nine West Virginia counties in the watershed have propane available. The results show that propane is readily available and will not be a potential hindrance to the deployment of the concept if it were economically and logistically viable. A complete listing of the propane availability by county is included in Appendix 1.

Section 4: Propane Assisted Biodigester System Design

Section 4.1: Anaerobic Digester System Design

Section 4.1.1: Reasons for Installing a Digester

Odor Control – This is the main reason that most farms that were interviewed installed the digester. Some were required to reduce the odor in an effort to be good neighbors, especially since residential areas are being built closer to farms. The digestion process converts the volatile organic compounds to methane and hydrogen sulfide (the smell in rotten eggs) and burns it in a generator, with the resulting digested manure (liquid and solid portions) being “significantly less” unpleasant than raw manure⁹.

Water Quality – Total Oxygen Demand (TOD), also referred to as Chemical Oxygen Demand (COD), “is a measure of how much oxygen could potentially be consumed by breaking down organic matter,” such as manure. This is an issue if there is a catastrophic spill of manure that enters surface water. If too much oxygen in the water is used to break down manure that spills into a stream, aquatic life will suffer or be killed. By reducing TOD, anaerobic digestion reduces the hazards of a potential catastrophic spill^{9,10,11}.

Greenhouse Gas Reduction – Both flaring and combusting the gas in an engine converts the gas from methane (CH₄) to carbon dioxide (CO₂). This is beneficial because CH₄ has a greenhouse gas effect, leading to increased global warming, that is roughly 21 times more potent than CO₂⁹.

Detailed phone and onsite interviews were done with several farms in New York, Pennsylvania, and Maryland.

Section 4.1.2: Anaerobic Digester Overview

Anaerobic digesters have been used for decades, in fact one mid-Atlantic region farm, Mason Dixon Farms in Pennsylvania, installed their digester in the 1970's¹². Digestion of animal manure can be done either in an anaerobic (absence of oxygen) or in an aerobic (presence of oxygen rich) environment. Farm digester systems use the anaerobic digestion process. The composting of the resulting solid material is the aerobic degradation process.

⁹ “Market Opportunities for Biogas Recovery Systems” U.S. Environmental Protection Agency, EPA-430-8-06-004.

¹⁰ Nelson, Carl and John Lamb, “Final Report: Haubenschild Farms Anaerobic Digester (Updated!)”, The Minnesota Project, August 2002.

¹¹ Roos, Kurt, “A Comparison of Dairy Cattle Manure Management with and without Anaerobic Digestion and Biogas Utilization”, AgSTAR Program, U.S. EPA, June 17, 2004.

¹² On-site interview with Richard Waybright of Mason Dixon Farm, Gettysburg, PA.

According to the U.S. Environmental Protection Agency (EPA) AgSTAR program, there are three main types of anaerobic manure digester technology available. These three technologies, shown in Figure 6¹³, are characterized as covered lagoon, complete mix, and plug flow digesters.

A covered lagoon digester is an earthen lagoon fitted with a cover that collects biogas as it is produced from manure. These digesters are best suited for flush or pit recharge manure collection systems with a total solids content ranging from 0.5-3% manure solids¹³.

A complete mix digester is a heated tank, constructed of either reinforced concrete or steel, with a gas-tight cover. The digester contents are mixed periodically, either by a motor-driven

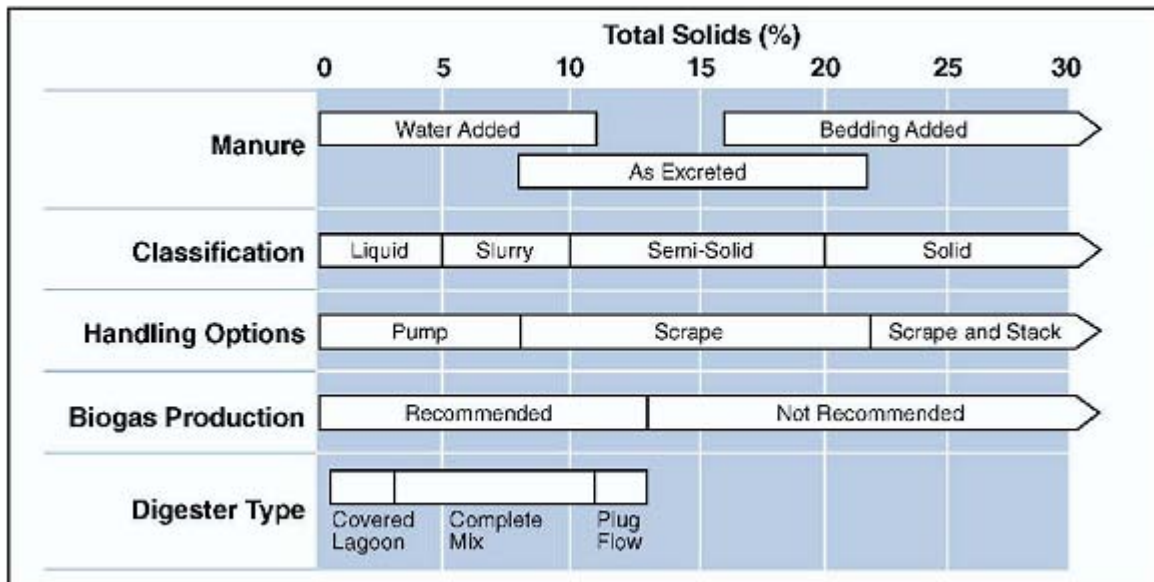


Figure 6: Biodigester Technology Graphical Representation

impeller or a pump to maintain an even mixture. This digester type works best with a manure slurry having a total solids content ranging from 3-10%¹³.

A plug-flow digester is a long, relatively narrow, heated tank, often built below ground, with a gas-tight cover. This type of digester requires manure with a total solids content ranging from 11-13%¹³.

Covered lagoon digesters are typically not heated due to their large diameter. As a result, biogas production rises and falls in relation to changes in ambient temperatures because of the changing activity level of the bacteria. Several farms in California have covered lagoon digesters since the temperature does not vary as much as in other areas such as the mid-Atlantic. Complete mix and plug-flow digesters are heated and maintain a relatively consistent environment for the bacteria, resulting in more consistent biogas production. These latter two

¹³ "Managing Manure with Biogas Recovery Systems". U.S. Environmental Protection Agency, Office of Air and Radiation, EPA-430-F-02-004, Winter 2002.

types of digester technologies are more appropriate for sustained power production and account for 77% of the installed digesters (51% plug flow, 26% complete mix)⁹. Plug flow digesters have been used only for dairy manure, while complete mix digesters can be used with a wider variety of animal manure.

A complete mix digester is used as an example to describe the digestion process. Manure is mixed with water, either during the manure collection or afterwards, to produce a pumpable slurry. There is a tradeoff between ease of pumping and nutrient/manure concentration. Slurry that is too thick cannot be pumped, while slurry that is too dilute requires a larger and more expensive digester.

A typical biogas recovery system has four basic components: an anaerobic digester, gas handling and conditioning equipment, an end use for the gas such as a generator, and an effluent storage tank for the liquid exiting the digester. Figure 7 shows an example schematic of a Biogas Nord digester installation with the various inputs and outputs¹⁴. Figure 7, below, illustrates a typical project schematic for a Biogas Direct installation. At the head of the process are two tanks, one for liquids and the other for solids. Since the complete mix systems generally requires a pumpable slurry, liquids including water, will be mixed with solids

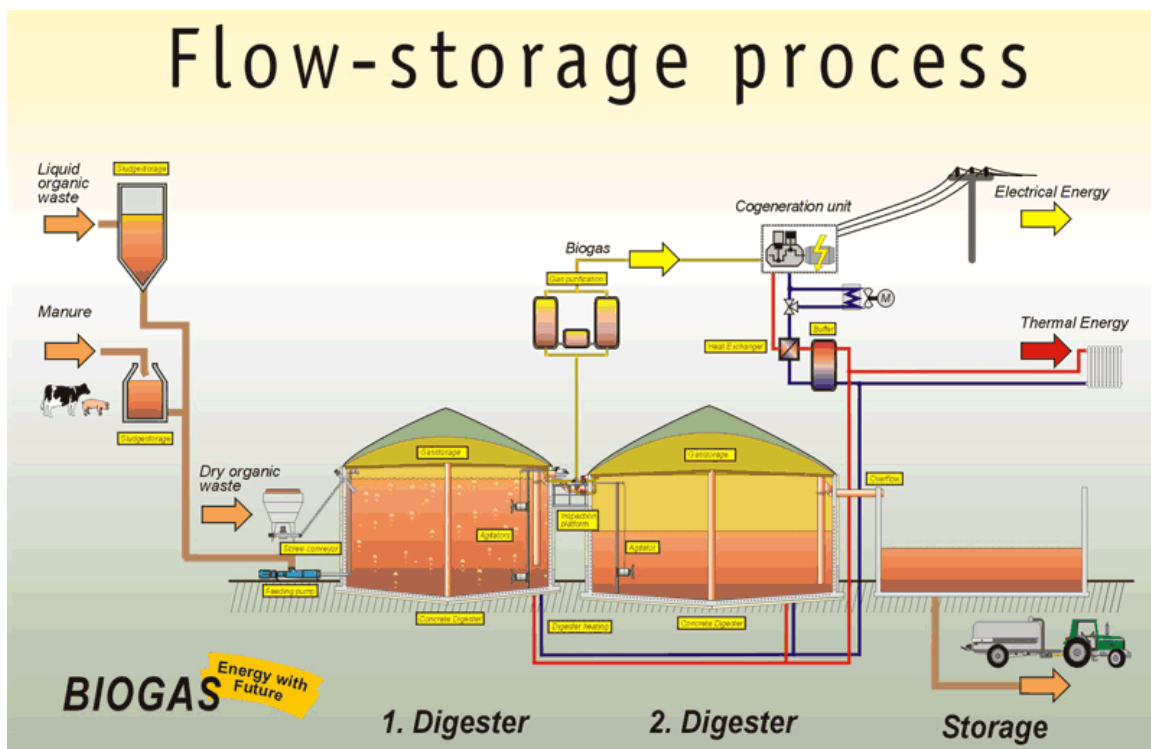


Figure 7: Typical Digester System Schematic

such as manure, to produce a slurry with the proper solids content. The slurry will be pumped into a two-stage digester, with the outfall of the first digester becoming the input of the second digester. The liquid portion of the slurry is discharged from the second digester and pumped

¹⁴ Biogas Direct website, http://www.biogas-nord.com/docs_en/technologie.html.

into a storage tank or lagoon until it is recycled as fertilizer, a soil amendment, or some similar use.

There are two sub-categories of digesters related to the temperature of the digester and the type of bacteria that perform the digestion. The types are mesophilic (88-106°F) and thermophilic (122°F). Mesophilic digesters are the most common and operate at a temperature slightly above a cow's rumen (the first division of the stomach). The bacteria involved in the mesophilic process are in the manure when it is excreted¹². However, operating a digester in the thermophilic range can produce much more gas due to the higher bacterial activity. Mason Dixon Farm experimented with operating their digester in the thermophilic range, but it is more expensive, requires more energy, is less stable than mesophilic digesters, requires complex controls, and produced much more biogas. The digester operating in the mesophilic range already produces more gas than required to offset the utility bill, so there was no rationale for taking on the additional workload^{12,15}.

Section 4.1.3: Nutrient Pollution Mitigation

Using an anaerobic digester was originally proposed as a method to decrease the phosphorous in the liquid effluent from the digester exit. Unfortunately, this is not the case.

The Penn State Biogas program states that some phosphorous (P) and potassium (K) will settle out in the digester, making it look like concentrations are mitigated in the digester, but the P and K "reappear" when the digester is cleaned out. "The microorganisms in the digester do not consume P and K. Some P can be converted to ortho-P (a soluble form) in the digester, but the total mass remains constant"¹⁶. Other studies agree, stating that the nitrogen, phosphorous, and potassium concentrations in the liquid portion are decreased by only 5% if the coarse solids are separated out; this is true whether or not anaerobic digestion is used¹¹. All of the farms that were interviewed indicated that the nutrients were not changed by the digestion process.

Phosphorous reduction is possible with a digester, but only if a separate post-digester step is added; Broumley Dairy in Texas is installing this type of system. The digester liquid effluent is pumped into a lagoon where algae are introduced. Just as was described in the section on the Chesapeake Bay water quality issues, these algae thrive on the phosphorous and nitrogen in the liquid, capturing the material in their structure. The algae are filtered out resulting in a drastic reduction (80% is targeted) in phosphorous concentration^{17,18}. Commercial products, such as BZT Waste Digester, that use bacteria to perform the same task are available¹⁹.

¹⁵ Wikipedia entry on anaerobic digestion, http://en.wikipedia.org/wiki/Anaerobic_digester.

¹⁶ Topper, Patrick, et al, "The Fate of Nutrients and Pathogens During Anaerobic Digestion of Dairy Manure", Agricultural and Biological Engineering Publication Number G71, <http://www.biogas.psu.edu/pdfs/G71.pdf>.

¹⁷ Texas Dairy Review website story, <http://www.texasdairy.com/archives/0509.htm#anae>, September 2005.

Section 4.1.4: Biogas Composition and Uses

The biogas produced is roughly 60-70% methane (the main component in natural gas). Carbon dioxide (CO₂) is roughly 30-40% of the stream and is a result of the fermentation process. Trace amounts of hydrogen sulfide and other compounds may also be found. Hydrogen sulfide is a combustible gas producing sulfur dioxide when burned. It is also weakly acidic and corrosive to metals, including those found in an internal combustion engine^{13,20,21}. Some digester systems use a desulphurization unit to remove hydrogen sulfide from the gas. The hardware for removing the hydrogen sulfide is an added expense that not all farms have used²². If this stage is not installed, the sulfur can slowly degrade the engine through the flow and combustion of the gas and sulfur collection in the lubricating oil. The farm mentioned above deals with this issue by changing the oil more frequently. However, this leads to a continual maintenance cost, more engine downtime, and higher petroleum product usage.

The biogas is collected and is either flared off or combusted in a cogeneration unit. Flaring the gas wastes the potential electricity production, but converts the gas from methane (CH₄) to carbon dioxide (CO₂). This is beneficial because CH₄ has a greenhouse gas effect, leading to increased global warming, that is roughly 21 times more potent than CO₂⁹. The cogeneration unit is typically a piston engine-generator set with jacketed exhausts. These jackets act as a heat exchanger that allow some of the waste heat to be recovered. The waste heat in turn can be used for process heat or space heat. The internal combustion process also converts CH₄ to CO₂. The most common engines are heavy-duty diesel engines that have been converted from compression-ignition (diesel cycle combustion) to spark-ignition (Otto cycle combustion) capable of operating on biogas. In fact all of the studies reviewed for the literature review and all of the interviewed farms except one use this type of engine. These engines will be discussed in more detail in a later section. Microturbines are small (30-70kW) turbine engines that can be used instead of piston engines to burn the biogas. Capstone Turbine Corporation (<http://www.capstoneturbine.com/prodsol/solutions/rrbiogas.asp>) is the most well known microturbine supplier. Only one farm located in the literature and through farm interviews, New Hope View Farm in New York, used a turbine engine. Their turbine was an Ingersoll Rand unit²³.

The energy content of biogas is lower than natural gas, due to the dilution with carbon dioxide. Natural gas has an approximate energy content of 1,021 btu/ft³. The biogas heating values

¹⁸ Dairy Farmers of America website story, http://www.dfamilk.com/dfa_leader/0508_Enviro.htm, July/August 2005.

¹⁹ United-Tech, Inc. BZT Waste Digester website, <http://www.united-tech.com/wd-ag-phosphorous.html>

²⁰ Ghafoori, Emad and Peter Flynn, "Optimum Sizing for Anaerobic Digestion", University of Alberta, March 2006.

²¹ Wikipedia page on hydrogen sulfide, http://en.wikipedia.org/wiki/hydrogen_sulfide.

²² Wright, Peter and Jjanguo Ma, "Anaerobic Digester at Spring Valley Dairy: Case Study", Case Study AD-6, Cornell Manure Management Program website, <http://www.manuremanagement.cornell.edu>, August 2003.

²³ Phone conversation with Trevor at New Hope View Farm.

vary, but are on the order of 600 btu/ft³ ¹⁰. As expected, the power rating for gensets run on biogas is lower than on natural gas, roughly by the same ratio. The engines are modified to use the lower-energy fuel by increasing the size of the carburetor fuel jets.

Section 4.1.5: Generator Ratings, Electricity Output, Efficiency, and Availability

The generator ratings found in the literature and through farm interviews revealed installed power ratings vary widely, from one 25kW genset to five 150kW gensets (750kW capacity). Based on the farms surveyed for this report, a typical average generator size would be in the 100-150kW range. Gensets are sized based on the number of cows, the capacity of the digester, and the farm's electricity usage. Net metering will be discussed in detail later in this report, but the major savings farms get from producing electricity is the avoided cost of purchasing electricity through the net metering agreements they have established with their electricity distribution utility. This cost includes the generation, transmission, and distribution elements of the pricing. Electricity in excess of what the farm uses is sold to the grid, but the farm is only paid on the generation portion of the cost (avoided cost of generation), so the payment is a much smaller amount and may or may not be profitable. Some farms were willing to accept the small profit and size the generators to use all of the biogas. Others have flared excess gas because even though they could sell the power, the additional capital and maintenance costs to operate the generators were too high to justify either installing or using them continuously.

Several examples were found where the biogas production exceeded the design specification, leading to the excess gas being flared. In several cases, the genset was sized to accommodate a planned herd expansion that ultimately did not happen. The lower resulting genset fuel input decreased the total conversion efficiency (biogas to electrical energy) to roughly 20%, rather than the 30% design efficiency. This situation highlights the fact that it is critical to properly size a genset to maximize its effectiveness.

Generator availability was found to be very high, between 95-99%. Engines were typically taken out of service for the regular oil changes and other periodic maintenance. None of the farms mentioned any engine failures.

Section 4.1.6: Generator Waste Heat Recovery

The primary purpose of the generator is to produce electricity to offset the farm's usage. However, waste heat recovery from the cooling water can provide a significant amount of heat that can be used for any process that requires heat such as space heating or hot water. This energy recovery benefits the farms through decreased purchases for the fuel being displaced such as propane, natural gas, or electricity.

Farm interviews showed that the waste heat is used for a variety of uses and in varying degrees. The primary use for the waste heat is to maintain the digester at a consistent temperature to provide a steady-state environment for the bacteria. There was no consistent pattern otherwise among the farms for how the heat was used. Several farms used the heat for barn space heating by pumping the hot water through radiant floor tubing^{10,24}. A.A. Dairy noted that they abandoned this method because a) there was not enough energy available because the uninsulated water loop lost too much heat in cold months to make it effective for space heating and b) the costs to convert the milking center from radiant to hot water were too high. Insulating the line would decrease the heat loss on long runs where heating was not necessary (such as from the digester to the barn), but has not been done²⁵. Similarly, Mason Dixon Farm did not use the waste heat because the barns are located too far from the digester and the water would lose too much heat during transport to be useful¹². As another example, the digester being installed at Cold Springs Farm in Maryland is located a ¼ mile from the barn and other buildings, too far to consider running water lines²⁶. Other farms used the recovered heat to pre-heat water before it entered a boiler that was used for various cleaning tasks. Several farms agreed that this seemed to be the most promising use for the waste heat. In many cases the logistics of routing the hot water to the end use location made it not worthwhile to use. Ultimately, the ability to cost-effectively reuse the recovered energy will be determined on a case by case basis.

Propane was previously being used for these heating tasks in several cases, but did not seem to be the predominant fuel to be displaced. At the high end of the spectrum, several California farms were able to reduce their annual propane cost by several thousand dollars per year by reusing the captured waste heat. However, in other cases the propane heat was not reduced.

Section 4.1.7: On-Farm and Centralized Digesters

An on-farm digester is located on a farm's property and is used to treat that farm's manure. None of the farms that were interviewed or in the literature had an on-farm digester that also treated manure from other farm(s). Farms can operate the digester system themselves, or hire a company to operate and maintain the system. The outside firm would be paid based on a percentage of the digester revenue. All of the farms interviewed have relatively small on-farm digester systems and are self-operated and maintained. This was also the case for all of the farms found in the literature.

A centralized digester could be located on one farm or could be located on a third party property, to treat manure from a group of local or regional farms. It is possible to have a centralized, or community, digester be operated by a few local farms working together, or by a third party company. The digester needs to be close enough to the farms so that the manure does not have to be trucked a long distance to limit transportation costs. This may be an

²⁴ Phone interview with New Hope View Farm.

²⁵ Phone interview with Bob Aman at A.A. Dairy Farm.

²⁶ Phone interview with Matt Hoff at Cold Springs Dairy.

attractive option for groups of smaller farms that do not have sufficient funds, or cows, to support an on-farm digester system on their own. Unfortunately, the size comparisons between on-farm and centralized digesters found in the literature are not necessarily straightforward. Small on-farm digesters may treat manure from as little as 200-500 cows. However, large on-farm digester systems handling 1,000, 2,500 and up to 6,000 cows also exist. The literature also discusses smaller centralized digesters sized to support ten farms and almost identical number of cows, 3,700 versus 4,000, respectively, including a Cornell University feasibility study²⁷ and a pilot project in Tillamook Bay, Oregon²⁸. Several farms in New York won a contract to install a centralized digester, but ultimately they determined that installing separate on-farm systems made more sense.

The main reasons for this project are to identify areas where digesters will affect (likely decrease) propane sales and to identify areas where additional propane use could augment the digester system to increase system efficiency as well as the profit for both the farm and for the propane industry. An important point is that centralized digesters will not impact the on-farm energy usage since the electricity and waste heat that are produced will not be used by the farms.

Section 4.2: Digester Payback Options

Section 4.2.1: Electric Power Sales

Section 4.2.1.1: Net Metered Power

Many states are developing, or have passed, net metering and interconnection requirement legislation to facilitate the growth of renewable power resources such as solar, wind, and methane derived from biomass, such as in anaerobic digesters. In a net metering power purchase agreement, the digester generator operates in parallel with the utility. The exact configuration is determined by the utility, but the net farm monthly energy use is determined by subtracting the energy supplied by the digester generator from the energy provided by the utility. The farm pays the difference if the farm produced less electricity than it used. However, if there is net power production, the farm will typically only be reimbursed for the avoided cost of generation of wholesale power (\$/kWh) by that utility. This payment pertains to the generation portion of the cost, not the distribution and transmission portions. The rates between farms will vary depending on the determination of the avoided cost of generation for each utility. Farms are paid this net metering payment once per year based on the net energy use over the annual period. All of the digester facilities in the literature and those that were interviewed are paid back from the utility only through net metering agreements.

²⁷ Bothi, Kimberly and Brian Aldrich, "Feasibility Study of a Central Anaerobic Digester for Ten Dairy Farms in Salem, NY", Cornell University Manure Management Program, Fact Sheet FS-3, <http://www.manuremanagement.cornell.edu/Docs/Salem%20fact%20sheet-6-7-05.htm>.

²⁸ Port of Tillamook Bay website page on Hooley Digester, <http://www.potb.org/methane-energy.htm>.

Since the focus of this study is the mid-Atlantic region, only net metered electric rates from this area will be discussed. Also, the study area was decreased to include only Delaware, Maryland, Pennsylvania, and New York based on the geographic proximity and potential for demonstration funding. The findings based on these states will be easily transferred to other states in the mid-Atlantic region and beyond.

Maryland

Maryland has net metering legislation in place, but no way is provided for farms to be paid back for excess power generation. Excess energy production is banked for one year, but if it is not used it is lost²⁹.

Pennsylvania

Schrack Farm is paid \$0.05/kW-hr for excess electricity production, only paid once per year³⁰. A later section describes this practice in more detail, but this appears to be standard practice in this industry. Mason Dixon Farm's (Gettysburg, Pennsylvania) agreement includes a time basis for changing rates through the day (i.e. peak vs. off-peak). They are paid back approximately ~\$0.025-0.03/kWh during peak hours (7AM-7PM) and \$0.0175/kWh off-peak, or roughly \$0.025/kWhr on average, including the generation and demand charges. Mr. Waybright mentioned that it costs them approximately \$0.0225/kW (including the digester system, genset, etc.) to produce the electricity, but that the production at least covers use¹².

New York

New Hope View Farm is paid \$0.07/kWhr for excess energy production²³. For comparison, Emerling Farm is paid \$0.085/kWhr³¹, while Patterson Farm is paid \$0.065/kWh³² and A.A. Dairy is paid approximately \$0.045/kWhr²⁵. Patterson Farm mentioned that their cost for generation, including the generator cost, maintenance and depreciation, is approximately \$0.02/kWhr. The farm saved \$77,000 through the net metering agreement, including avoided electricity costs and sale of excess power last year. However, the farm also had \$14,000 in oil use and change costs and \$25,000 in maintenance costs for the generator, resulting in an approximate final profit of \$38,000. The system was installed for odor control, so this income is considered a bonus.

Section 4.2.1.2: Peaking Power

The utility companies did not discuss using the biogas generators to produce peaking power. This is logical because an anaerobic digester is designed for continual biogas production and power generation. Digester systems include a gas storage section, but the capacity is likely not large enough to satisfy a sustained peak demand. Peak power production agreements

²⁹ Phone conversation with Chris Rice, Biomass Program Manager, Maryland Energy Administration.

³⁰ Phone conversation with James Harbach at Schrack Farms.

³¹ Phone conversation with Mike Emerling at Emerling Farms.

³² Phone conversation with Connie Patterson at Patterson Farms.

require a definite amount of power that the facility will provide. This is straightforward when dealing with a generator fueled with a natural gas line, or connected to a large propane or diesel tank with enough fuel for the maximum peak power period. As will be discussed in a later section, the utility companies were not responsive to requests for information so definite answers regarding power, availability, etc. cannot be answered at this time.

Section 4.2.1.3: Augmenting Digester Input with Additional Digestible Material

This is an interesting approach, where additional digestible materials are added into the input stream to provide more food for the bacteria. Food processing waste is being used by two of the interviewed digesters. The Cold Springs Farm digester in Maryland is under construction and will have an output power capacity of 1.2MW. Only two hundred kilowatts (200kW) will be from cow manure; the remaining power will be the result of digesting food processing waste. Patterson Farm in New York augments the digester input stream with food waste (whey from Kraft cheese processing) for additional energy. The additional input results in more biogas and more power for sale. The farm also charges a tipping fee of \$0.06/gallon, which at the approximately 18,000 gallons/day equates to \$394,000 per year in additional revenue. This is significant because the tipping fees alone lead to a payback within 3.5 years³².

Section 4.2.2: Renewable Energy / Carbon Offset Credits

Net metering and interconnection standards efforts are often linked with renewable portfolio standards (RPS). This is a top down approach to getting small solar, wind and biomass projects online easily. These guidelines/standards facilitate connecting these sites to the grid and getting the producers the standard retail rate. However, they do not require that a generation capacity payment (\$/kW of power generated) be paid. If available, these credits would give additional income for the digesters to improve the economics. The RPS only structures renewable energy credits, and not greenhouse gas credits (also known as “carbon credits”). Selling these carbon credits is another potential revenue stream for a facility.

The Cold Springs Farm digester in Maryland is unique because it is not connected to the electrical service of the rest of the farm. Therefore the power produced is not used for a net metering agreement. Instead they have brokered a power purchase agreement deal with a third party company to sell the electricity. The other major difference with this farm is that the power purchase agreement allows the farm to be paid both for the electrical energy (approximately \$0.015/kWh) and a premium for the renewable energy credits (REC) (approximately \$0.07/kWhr); \$0.085/kWhr total^{Error! Bookmark not defined.}. This is an average rate in New York State, but is a very good rate for the Maryland and Pennsylvania area.

Section 4.2.3: Waste Heat Recovery

The amount of available waste heat depends on the generator capacity. How effectively the waste heat can be recovered depends heavily on how the farm decides to deal with the

energy, as noted before. In some cases farms knew that they could recover and use more of the wasted energy, but had not done so because of the time involved and because it was a diversion from their main business: to produce milk. The logistics of where buildings and processes happen on the farm heavily dictate the ability to use recovered energy.

Section 4.2.4: Waste Solids Sale

The digester solids can be separated out from the manure slurry using a screw press or similar device before being pumped from the digester into the holding tank or lagoon. The material is not dry to the touch, but was found to be suitable by one farm to use directly as an animal bedding material, either to offset on-farm purchases or by selling to other farms. Other farms air dry the material before using as bedding.

The digested solids can also be composted by placing them in windrows in a field. Composting requires moisture so the material need not be completely dry before composting. A.A. Dairy mentioned that the anaerobic digestion process reduces the time by 25%. They have been very successful at producing compost and marketing it as a renewable resource to landscaping companies²⁵.

There was a wide range in how effective and profitable the treating, use, or resale of these solids was for farms.

Section 4.2.5: Decreased Fertilizer Purchases

Farms typically spread manure, either in liquid or solid form, on the fields to fertilize the soil. Several farmers explained their soil and manure testing processes (to determine the nutrient concentration in each) that guide how the manure will be spread on each field. This is done whether the manure has been treated in a digester or not. In fact, since the main reason farms installed digesters was odor reduction, it reinforces the belief that the manure was and will be spread on the fields. It is assumed that the digester does not significantly affect the fertilizer costs since the manure is used in either case.

Section 4.2.6: Pipeline Gas

New York State Electric & Gas Corporation (NYSEG) mentioned that their current high priority concept is purifying biogas to feed into the natural gas pipeline to use where it is needed. The idea is that the hardware cost and maintenance along with the inherent inefficiencies to convert biogas into electricity is a less efficient and less flexible use for the gas. The NYSEG representative said that they are still trying to determine what “pipeline quality” means to be able to determine how much treatment the gas would require³³. This concept is essentially the

³³ Phone conversation with Jim Harvilla, Research and Development Department, New York State Electric & Gas Corporation.

same as for landfills that capture the landfill gas and clean it up and introduce it into the pipeline. Patterson Farm only uses a third of their biogas to generate power. The remaining gas is flared, essentially wasting the energy. They are interested in the sale of propane fueled peaking power concept. The farm is also in the process of determining what gas purification hardware is necessary for the gas quality to be suitable for putting directly in the pipeline. They have submitted a NYSERDA proposal to do this³².

Section 4.3: Propane Augmentation

Section 4.3.1 Dual Fuel Genset/Turbine Technology

The genset is typically a piston engine-generator, most commonly using heavy-duty diesel engines that have been converted from compression-ignition (diesel cycle combustion) to spark-ignition (Otto cycle combustion) capable of operating on biogas. All but one of the farms reviewed or interviewed used this type of engine. Microturbines are small (30-70kW) turbine engines that can be used instead of a piston engine to burn the biogas. Capstone Turbine Corporation (<http://www.capstoneturbine.com/prodsol/solutions/rabiogas.asp>) is the most well-known supplier. New Hope View Farm in New York was the only farm surveyed that used a microturbine (Ingersoll Rand). Since piston engine generators are the industry norm, microturbines and small gas turbines will not be covered further in this report.

Section 4.3.1.1: Original Engine Manufacturers

Four main stationary generator set engine manufacturers were identified including: Waukesha Engine, Cummins, Caterpillar Power Generation, and General Electric Energy Jenbacher Division. Cummins, Caterpillar, and Waukesha have engine-generator sets rated for 100 to 200 kWh of electric output when fueled with natural gas. These engines are designed to produce continuous power and are typically connected to a natural gas line. Fueling with a liquid fuel like propane would require an additional fuel tank. The smallest engine from GE Jenbacher is rated at 250kW on natural gas and 230kW on propane. All three manufacturers offer versions of engines designed to operate on lower energy/quality biogas (e.g. biodigester methane gas or landfill methane gas).

Waukesha Engine – Joe Lange, the Eastern Regional Sales Manager from Waukesha Engine, was called to discuss the project and the goals of augmenting the fuel stream with a dual-fuel (biogas/propane) system. In addition to the natural gas engines mentioned above, the company also has dedicated propane fueled versions of their engines. They also offer dual-fuel engines where the engine can operate solely on one fuel such as biogas, or solely on another fuel such as propane. This fuel switching feature is desirable for customers who want to have a failsafe in case one fuel source is not available. Natural gas-propane and natural gas-biogas dual-fuel models are available, but biogas-propane models are not available. Unfortunately, the dual-fuel engines cannot be operated with a variable blending of the fuels.

Mr. Lange said that he did not see any reason that a biogas-propane dual-fuel engine could not be produced, but that there has been no market demand to develop such a product. He estimated that the cost difference between a dedicated biogas and a biogas-propane dual-fuel engine would be roughly the same \$4,000 difference as for either a natural gas-biogas or natural gas-propane engine. The primary issue with developing a variable blend dual-fuel (biogas-propane) engine is how to control the combustion when two gases with very different energy contents (biogas is approximately 600 btu/ft³, while propane is approximately 2,500 btu/ft³³⁴) are mixed. Theoretically, the two gas streams could be used in this blended approach, but would require a dual-fuel carburetor and additional control to properly meter the fuel to account for the caloric value of fuel-air mixture entering the engine³⁵. He also felt that the power rating when operating on propane would be roughly equivalent to biogas since the ignition timing would have to be retarded for propane due to the higher combustion temperatures and fuel properties. One of the initial reasons for considering a dual-fuel (biogas-propane) arrangement was to take advantage of the higher power output when running on propane for power output stabilization, or for producing peaking power. The fact that the propane output power would be equivalent, or less, than on biogas, leaves no reason to consider this option. The fact that propane fuel would be an additional cost, with no benefit to the farm, reinforces this finding. The baseline cost for a 150kW Waukesha genset would be \$144,000, including the dual-fuel modifications.

Caterpillar Power Generation - Caterpillar engines are the most common genset used for digester systems. The Caterpillar product line is similar to Waukesha Engine engine-generator sets where the propane and biogas cannot easily be combined prior to entering the engine. Caterpillar engines are also carbureted and would thus require additional design, hardware and customization to allow simultaneous use of propane and biogas. The contact felt that the propane would have to be diluted prior to the intake so the effective fuel energy density would be equivalent to biogas. As with the Waukesha engines, this defeats the purpose of adding the dual-fuel capability³⁶.

General Electric Energy Jenbacher – These generator sets differ from the previous manufacturers because of the fuel-air management system design. GE engines use a proprietary induction and mixing device in the intake instead of a simple carburetor. This gas mixer allows several fuel streams with different caloric values, such as biogas and propane, to be combined together. Since the engines come equipped with this mixing technology as a standard feature, there would be no additional engine-related cost for using propane and biogas in various proportions. Unfortunately, the smallest engine-generator set in GE's product line is rated for 335 kWh electric output when fueled with natural gas. The output power rating when fueled with biogas was estimated to be on the order of 200 kWh, based on the

³⁴ National Propane Gas Association webpage, <http://www.npga.org/i4a/pages/index.cfm?pageid=633>.

³⁵ Phone conversations with Joe Lange, Eastern Regional Manager, Waukesha Engine.

³⁶ Phone conversation with Bob Smith with Cleveland Brother Caterpillar - Power Systems Engineering Division.

assumption that the biogas is 60% methane, according to an application engineer from GE³⁷. This is too much power for most of the farm-based systems found in the literature survey. The GE Jenbacher unit cost with the required cooling system and electrical connection hardware is \$260,000.

Section 4.3.1.2: In-Use Digester Gensets

From the discussions with engine manufacturers, it seems that operating an engine on biogas requires a complex solution that, in some cases, has not yet been designed. The farms were asked whether their genset engines were designed for biogas, natural gas, or propane. In many cases they did not know because the engines were provided by the digester system provider and work well, so there was no need to investigate further. Several farms, however, said that the engines were originally either a dedicated natural gas or dedicated propane engine, based on a diesel engine, that was modified by a third party to run on biogas with larger fuel jets and modified timing. Several farms mentioned that they would start the engine on 100% propane for the initial digester heat up since propane has higher power, and thus provides more waste heat energy. The engine is then switched from propane to biogas: the transition is smooth and unnoticeable. The only noticeable difference is a change in engine speed as a result of the output power difference. They did not provide an exact description of the hardware involved, but explained the process such that the fuel source control switch would close the fuel valve for one fuel while opening the fuel valve for the second fuel. Emerling Farm noted that their genset supplier, Martin Machinery from Latham, Missouri, has biogas system experience dating from the 1970's^{31,38}, performed the modifications, and is comfortable with switching between 100% biogas and 100% propane, but is not comfortable blending the fuels.

Richard Waybright with Mason-Dixon Farm suggested a similar alternate method where the propane gas could be introduced directly into the biogas supply line before the gensets. The gas line in Mason Dixon Farm's digester is roughly one foot in diameter and is fully accessible ahead of the gensets¹². Since it seems that the genset engines are capable of operating on either 100% biogas or 100% propane without any control or engine mechanical modifications, even though the engine manufacturers seem to be unaware of this practice, it would seem that installing a gas proportioning valve in the gas line to blend the biogas and propane at varying percentages would be feasible for introducing the propane into the system. A control system for the valve would have to be developed and could use required power output, electricity buyback rate, or any other relevant parameters for control. In fact, Emerling Farms in New York has considered doing this since his genset outputs 180kW operating on biogas and 250kW operating on propane³¹.

³⁷ Phone conversations with Robert Roy, Applications Engineer, GE Energy Jenbacher Gas Engines North America.

³⁸ Goldstein, Nora and David Spencer, "What's New? Biogas Power?", repost of Biocycle, February 2007 article, <http://www.environmental-expert.com/resultteachmagazine.asp?cid=6042&codi=3549&idproducttype=9&idmainpage=&level=0>.

Section 4.3.2: Propane Genset Augmentation Options

The propane-augmented biodigester concept was envisioned as a hybrid power (biogas-propane) distributed generation project. The biogas will be the primary fuel source for generating electricity and heat through most of the year. Propane was envisioned as augmenting the gas stream when the biogas production is insufficient. Propane was also proposed to be used as the primary fuel during peak electric demand periods to ensure a reliable supply of electricity and because the electrical output power operating on propane is higher than on biogas.

When the project was started it was believed that a thorough understanding of digester systems operation, efficiency, gas production, generator reserve capacity, and other detailed information was necessary. However, the project really focuses on the generator(s) and how they are used. Therefore the available reserve capacity and the generator capacities are the only important variables for determining the energy production and financial impact on the farm.

Section 4.3.2.1: Power Stabilization

It was believed when this project was proposed that an anaerobic digester may need to augment the generator fuel stream when the biogas production was below a limit needed to produce the required electrical power. Examples of when this may have been the case were when the digester was not adequately charged with manure and during periods of cold weather. The amount of manure being fed into the digester is more or less constant since it is a function of how many cows the farm has and their diet.

Temperature is an issue for digesters because the bacteria activity decreases in cold weather, such that the retention time in the digester increases. A mini-ecosystem is created in the digester for the bacteria. Maintaining the ecosystem at equilibrium is the ideal case for the bacteria to reduce stresses on their health and to maximize their ability to process the manure. An earlier section described the three main digester designs: covered lagoon, complete mix, and plug flow. Covered lagoon digesters are typically unheated. None of the studies found in the literature used a covered lagoon digester in cold weather climates such as the mid-Atlantic. Complete mix and plug flow digesters use generator waste heat to maintain the temperature in the digester in the proper range. All of the mid-Atlantic digesters that were located through farm interviews or through the literature were either complete mix or plug flow designs.

All but one farm said that their gas production was fairly consistent year round. A.A. Dairy in New York experiences approximately a $\pm 17\%$ fluctuation in gas production²⁵. Emerling Farm in New York has similar experience with a $\pm 14\%$ fluctuation overall, or a 25% decrease in gas production in the winter³¹. New Hope View Farm in New York saw outputs that varied between 40-70 cfm, based on ambient and ground temperatures and the moisture content in the manure²³. The remaining farm, Mason Dixon Farm in Pennsylvania, said their digester

produces gas very consistently. Their digester tanks are below ground, so they will fluctuate less than tanks exposed to ambient temperatures. They also said that the cows are fed the same diet year round, so the manure input is consistent¹².

These issues address the technical aspects of continual digester gas production. However, the other side of the equation that needs to be addressed is how the farm is paid back for the power produced. An earlier section mentioned net metering, and it will be discussed from the utility perspective in a later section. Net metering agreements were designed for renewable power production such as solar, wind, and biomass derived methane, such as in a digester. In a net metering power purchase agreement, the digester generator operates in parallel with the utility. The exact configuration is determined by the utility, but the net farm monthly energy use is determined by subtracting the energy supplied by the digester generator from the energy provided by the utility. The farm pays the difference if the farm produced less electricity than it used. However, if there is net power production, the farm will typically be reimbursed only for the avoided cost of generation of wholesale power (\$/kWh) by that utility. This payment pertains to the generation portion of the cost, not the distribution and transmission portions. The rates between farms will vary depending on the determination of the avoided cost of generation for each utility. Farms are paid this net metering payment once per year based on the net energy use over the annual period. This last point is critical because it means that it is not important to maintain the instantaneous or even monthly average, energy production at a consistent level to satisfy the net metering agreement. Farms were asked if they understood their agreement in this way and all agreed. The farms were also asked whether they saw any other reason for augmenting the fuel stream with propane, or any other fuel, and they did not. The reasoning is very logical, as the biogas is essentially a free resource, so the power production is essentially a free side benefit. There would be no financial incentive for adding a fuel that they would have to pay for (propane, natural gas, diesel, etc.).

This concept was discussed with the utility and they agree with this logic. Additionally, utilities are required by law to accept renewable power through net metering agreements. Whether the addition of propane (or any other non-renewable fuel) would invalidate the requirement that the utility purchase the power, or would cause other issues with the utility being required to accept the power, is not known since this concept has not been discussed.

If farms felt there was a need to stabilize the power production in the future, one potential solution would be to install additional biogas storage capacity. Digester systems have a biogas storage section, such as a large bladder gas bag on top of the digester tank or inline between the digester and generator(s), that buffers the gas flow to smooth out any fluctuations. The potential benefit for the farm with this arrangement would be that the power would all be derived from renewable resources and would not invalidate the net metering agreement. These reasons suggest that augmenting the biogas input stream with propane to stabilize the power output is not currently a reasonable option.

Section 4.3.2.2: Peaking Power Production

The sale of peaking power has the potential to be profitable for both the farm and for the propane industry. Peaking represents a small portion (approximately 5%) of annual usage, but the rate (\$/kWhr) is much higher than for base load wholesale energy purchases.

A study done by Green Mountain College, the University of Albany, and the National Renewable Energy Laboratory highlighted the overlapping availability of solar PV with peak power demands³⁹. Peak pricing examples were shown for California (CalPX), New England (New England ISO), Mid-Atlantic (PJM), and New York (New York ISO). Examples of the drastically changing rate profiles were compared during hot days in the northeast, comparing two days to show the profile differences. The example rates shown in Figure 8 from May 8, 2000 for ISO New England rose sharply to the price cap of \$6.00/kWh and held there for a period of more than three hours. The example data from New York ISO from June 26, 2000 has a different profile where the rates increase much earlier in the day and are at \$0.50/kWh by 10AM, compared to Noon for New England ISO. The peak pricing reached the cap of \$1.00/kWh and held there for four hours. The report shows that peak prices are paid on a consistent basis during the hot summer months when air conditioning loads are highest.

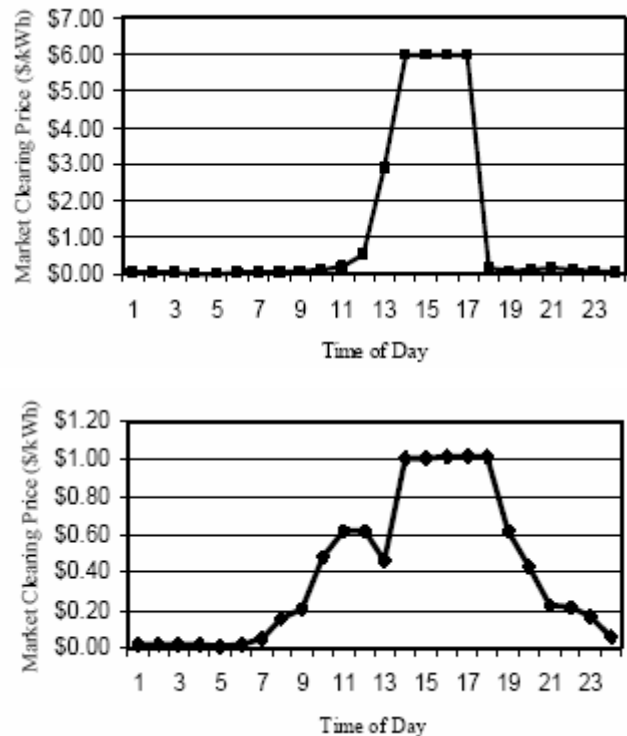


Figure 8: Example Daily Demand Pricing Curves (Top-New England ISO, Bottom-New York ISO)³⁹

Figure 9 shows the market price paid in several days in California in 2000. The price of \$0.50/kWh is the averaged price over the period and may likely have actually been much higher during a short portion. Figure 10 shows similar data for the PJM territory. Some of the peak power prices were lower than in California, but others were equal to California, reaching the price cap of \$1/kWh. Figure 11 shows similar data for New York ISO and again shows that prices above \$0.50/kWh were frequently paid.

³⁹ Steven Letendre, et al, "An Assessment of Photovoltaic Energy Availability During Periods of Peak Power Prices", 2001.

Figure 12 provides an example to show that peak pricing rates of these magnitudes continue to be paid today. The example data is from August 8, 2007, which was a hot summer day (Baltimore reached a high of 102°F). Real-time locational marginal pricing data taken from PJM's website reinforce the high prices paid during peak demand periods. In fact, as Figure 11 shows, the price average price in the entire PJM territory reached \$0.76/kWh. This value is somewhat misleading because it indicates an hourly average rather than showing the prices paid for the 15-minute blocks that make up each hour, some of which can be much higher⁴⁰.

Date	Time	Location	Market Price
5/28/2000	4:00 PM	South, CA	\$0.60/kWh
6/28/2000	2:00 PM – 6:00 PM	North, CA	\$1.09/kWh
7/25/2000	3:00 PM – 5:00 PM	South, CA	\$0.50/kWh
7/31/2000	1:00 PM – 7:00 PM	South, CA	\$0.50/kWh
8/1/2000	12:00 PM – 8:00 PM	South, CA	\$0.50/kWh
8/2/2000	12:00 PM – 8:00 PM	South, CA	\$0.50/kWh
8/3/2000	12:00 PM – 7:00 PM	South, CA	\$0.50/kWh
8/4/2000	3:00 PM – 5:00 PM	South, CA	\$0.50/kWh

Source: CalPX

Figure 9: Example of Sustained High Peak Power Pricing (California)³⁹

Peak power rates in the range of \$0.75-\$1/kWhr have been shown to be typical. These rates represent an increase of between 8.8 and 40 compared to the wholesale base load power rates the interviewed farms are currently paid. Unfortunately, exact figures of hours per year or rates were not available. A later section describes the difficulty or unwillingness of the utilities to discuss this project.

Traditional peaking plants have significantly higher power production capacity (tens to hundreds of MW) than anaerobic digester generators (tens to hundreds of kW). These peaking plants are paid based on both the energy that is produced (\$/kWhr) and a capacity payment (\$/kW-year). Mr. Birge with the Pennsylvania Public Utility Commission and Mr. Harvilla with the New York State Electric & Gas Corporation both agreed that if a peaking agreement was made with a digester farm, a capacity payment would likely not be offered.

There are several options for how propane could be used to produce peaking power: 1) by oversizing the genset(s) so it is typically operated at less than full load to reserve capacity for peaking power production, 2) by switching one or more genset(s) to operate on propane during peak demand periods and, 3) by using propane in a separate dedicated peaking genset(s). Most of the interviewed farms had only one generator, so many of the

Date	Time	Location	Market Price
6/8/2000	4:00 PM – 5:00 PM	Southern Delaware	\$1.00/kWh
5/8/2000	2:00 PM – 4:00 PM	Entire control area	\$0.48/kWh
7/3/2000	5:00 PM – 6:00 PM	PEPCO	\$0.19/kWh
8/8/2000	3:00 PM – 5:00 PM	Entire control area	\$0.14/kWh

Source: PJM

Figure 10: Example of Sustained High Peak Power Pricing (Mid-Atlantic)³⁹

⁴⁰ PJM website for Real-Time Locational Marginal Pricing, <http://www.pjm.com/markets/jsp/lmp.jsp>.

options and cases below would require purchasing an additional genset.

As an example for the first option, one study discussed a digester system where a larger generator was installed to allow for an approximate doubling of the herd size. As a result, the genset was operated at roughly half of the maximum design gas utilization rate, resulting in an energy conversion efficiency drop from the expected 30% to 20% (a 33% decrease)¹¹. Since the need for peaking accounts for approximately only 5% (438 hours) of the year, it would likely not be logical to absorb a 33% efficiency drop for the remaining portion (8,322 hours) of the year. The peak energy buyback rate value (\$/kW-hr) would have to be very high to make this a viable decision. This break even point will be determined in the economic analysis to follow, but it does not appear to be a good option.

Date	Time	Location	Market Price
6/26/2000	1:00 PM – 5:00 PM	Eastern NY, Albany - NYC	\$1.30/kWh
8/9/2000	1:00 PM – 2:00 PM	Capital District	\$1.07/kWh
6/26/2000	1:00 PM – 5:00 PM	Long Island	\$0.82/kWh
8/9/2000	1:00 PM – 2:00 PM	Long Island	\$0.62/kWh
7/5/2000	2:00 PM – 4:00 PM	Capital District	\$0.21/kWh

Source: NYISO

Figure 11: Example of Sustained High Peak Power Pricing (New York)³⁹

For the second option, it was originally envisioned that the current genset, and/or an additional genset, would be equipped with a dual-fuel system to allow for blending of the fuels anywhere from 100% biogas to 100% propane. This genset(s) would be fueled by propane during peak demand periods. The biogas produced during peaking periods will either have to be flared off or the system will have to have adequate storage if propane was used in all of the generators for peaking power. The

specifics of this type of fuel system and the impacts on the engine output power were discussed in an earlier section. The reason for switching to propane was to provide firm power since the power output would not be affected by fluctuations in the biogas fuel supply volumes, and because of the higher power output. However, all of the engine manufacturers

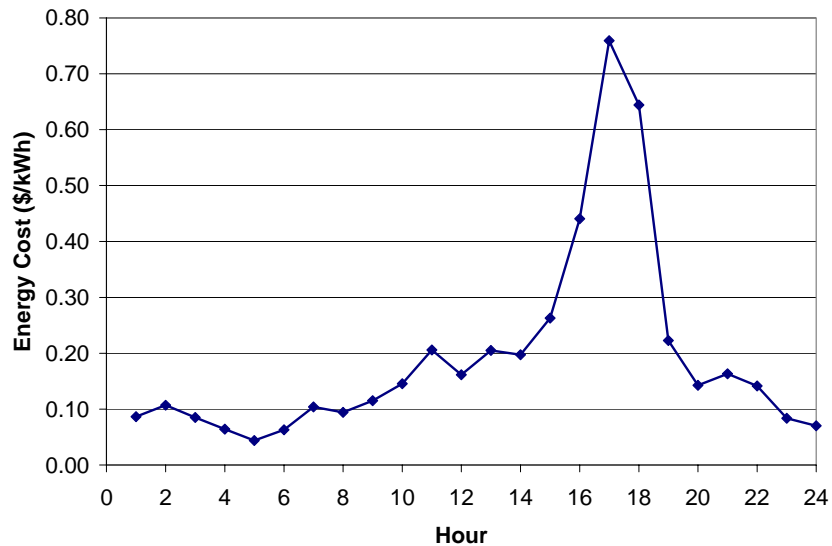


Figure 12: Real-time Peak Power Purchase Rates in PJM for August 8, 2007⁴⁰

thought that a dual-fuel setup would result in either the same power, or only slightly higher power, when operating on propane. The farm interviews revealed that several current digester gensets are equipped with a fuel system that allows the engine to be operated on either 100% biogas or 100% propane. These owners have seen the anticipated increased power production on propane. Emerling Farm has seen a power increase from 180kW to 250kW (39% increase) when switching from biogas to propane fuel³¹. This gives the higher output without the additional cost, approximately \$4,000, of the dual-fuel system.

There are additional potential side benefits from adding a generator to a digester system that currently only has one generator. Utilities assess the farms with a demand charge based on the 15-minute period with the highest power (kW) usage. The generators operate continuously throughout the month and are only shut down for periodic maintenance (oil changes, periodic maintenance, overhauls, etc.). Therefore, if the highest electricity demand happens during this period, the farm can be assessed a demand charge. Emerling Farm said they pay between \$500 and \$1,800 per month³¹.

The first benefit is that the farm would be able to run one generator while the other was being serviced (oil changes, periodic maintenance, overhauls, etc.).

The third option investigated was to add a dedicated standby propane peaking generator. The belief was that since the engine would not be run continuously that the engine displacement, and thus cost, would be lower for a given power rating (i.e. the \$/kW cost). For example, a Ford V10 gasoline engine is rated for use in an industrial application at approximately 225hp; however it is rated for vehicular usage at 305hp, approximately 35% higher. Caterpillar generators can be used as an example since they are the dominant genset manufacturer. Based on the farms surveyed for this report, a typical average generator size would be in the 100-150kW range. Unfortunately, there is a small or nonexistent power rating difference between the standby and continuous ratings for these gensets. Therefore, the same genset would be selected, so there is no cost savings in this approach.

Five cases were identified for further analysis to determine their economic viability. An assumption is that the digester currently uses only one generator, since that was the most common situation. Many farms mentioned that they flare excess gas, so it is also assumed for cases 4 and 5 that there is sufficient biogas left over to fuel an additional generator. Thus, using the previously wasted excess gas to produce electricity will provide the farms with all of the potential returns for their investment in both the digester system and the additional genset. The cases are summarized in Table 1.

- Case 1 - Uses only the existing generator, but switches to 100% propane for consistent power production.
- Case 2 - Uses only the existing generator, but switches to 100% propane for peak power production (approximated at 5% of annual hours).

- **Case 3** – Uses the existing generator fueled only on biogas producing net metered power. An additional propane peaking generator is added to operate only during peak demand periods. The added benefit of avoiding the monthly demand charge when one generator is operated when servicing the other generator will be factored into this calculation.
- **Case 4** - Uses the existing generator fueled only on biogas producing net metered power all year. An additional propane peaking generator is added to operate on biogas for 95% of the year and on propane for the remaining 5% of the year during peak demand periods.
- **Case 5** - Uses the existing generator fueled only on biogas producing net metered power for 95% of the year and on propane for the remaining 5% of the year during peak demand periods. An additional generator is added that operates just as the primary generator does; on biogas for 95% of the year and on propane for the remaining 5% of the year during peak demand periods.

Table 1: Summary of Propane Augmentation Cases

Case	Current Generator	Additional Generator
1	Biogas (98%) + propane (2%)	n/a
2	Biogas (95%) + propane (5%)	n/a
3	Biogas (100%)	Propane (5%)
4	Biogas (100%)	Biogas (95%) + propane (5%)
5	Biogas (95%) + propane (5%)	Biogas (95%) + propane (5%)

The farms were asked whether they would consider adding peak power generation capacity if it would be accepted by the utility and was economically viable. All of the farms reinforced that their main purpose is to operate a dairy farm to produce milk, not power. However, the market is very competitive and farms are always looking for additional revenue streams.

Section 4.3.3: Other Potential Uses For Propane in On-Farm Digester Operation

Digester farms were asked whether there were other potential areas in the digester system operation, from manure collection to drying and composting the waste solids, where propane could be used to improve the process, increase the efficiency, or to increase the digester financial case, thus increasing propane sales.

Section 4.3.3.1: Initial Digester Warm Up

It was mentioned earlier that Schrack Farm in Pennsylvania performed the initial warm-up to bring the digester to operating temperature with propane. This approach was taken because the engine produces more waste heat on propane and heats up the digester faster³⁰. Another farm mentioned that the digester will cool by approximately one degree Fahrenheit per day

when fully charged but not operating so this practice is likely not necessary even if the digester generator is not functioning for several days.

Section 4.3.3.2: Drying Digester Solids

As mentioned earlier, the digested solids can be used as animal bedding or composted for use or sale as soil amendment. Farms were asked what methods they used to prepare the solids for use and whether using propane to speed up the drying process was necessary or an interesting idea worth considering. Patterson Farm in New York and Schrack Farm in Pennsylvania run the digester solids through a separator that extracts most of the water before use as bedding material^{32,30}. Patterson Farm does not dry the material beyond this³². Schrack Farm air-dries the material and said that it dries quickly, so there is no need for any alternate drying method, especially since it would only add cost. A.A. Dairy in New York felt that it would be cost prohibitive to use propane for drying the digester material for bedding²⁵.

A.A. Dairy in New York composts the digested solids. The composting process requires moisture to take place, so drying is not needed; it would actually hinder the process. The process is exothermic and reaches a temperature between 140°F and 150°F, so the material dries on its own at the end of the composting process²⁵. Emerling Farm in New York plans to compost their digester solids, but agree that they do not need to be dried before use³¹.

Section 5: Potential Interconnection and Utility Issues

Section 5.1: Interconnection and Net Metering Requirements

The electric utility companies operating in the mid-Atlantic region in Delaware, Maryland, and Pennsylvania operate either in the PJM Interconnection regional transmission organization area (www.pjm.com) or the New York Independent System Operator (www.nyiso.com) organization areas. PJM includes eight utilities: Allegheny Power, Baltimore Gas and Electric, Delmarva Power and Light Company, Metropolitan Edison Company, PECO Energy Company, PPL Electric Utilities Corporation, Pennsylvania Electric Company, and Potomac Electric Power Company. NYISO includes all of New York State and includes: Central Hudson Gas & Electric Corporation, Con Edison, Long Island Power Authority, New York Power Authority, National Grid, New York State Electric & Gas Corporation, Orange & Rockland, and Rochester Gas & Electric Corporation.

Each utility has its own specific rules regarding how small scale power generation and cogeneration facilities are able to operate, what is required to connect to the grid, and the rate structure at which they will buy power back. The definition of “small scale” depends on the utility. For example, Allegheny Power considers this to be below 50 kW⁴¹. The New York Public Services Commission standardized the interconnection requirements for distributed generation sources such as digesters to streamline the process and requirements for new facilities⁴².

Appendix 2 has a summary of interconnection requirements, contacts, and references.

Section 5.2 Utility Perspective on Concept

Several utilities (Allegheny Power, PPL, PECO, Metropolitan Edison, NYSEG) were called at the beginning of the project to discuss the concept and to determine the requirements and willingness of the utility to allow this type of facility to connect and get compensated for the power production. The initial round of calls with specific utility contacts familiar with net metering and cogeneration facilities was not encouraging and never yielded any return calls. During the farm interviews, farmers were asked to share their utility contact to provide an entry point at the utilities to find the right person(s); Mason Dixon Farm is one of these farms. Kevin Seidt, their Metropolitan Edison (part of the FirstEnergy family) account manager, was called. The project and its goals were discussed. Mr. Seidt did not have enough knowledge or authority to provide any insight on how FirstEnergy would treat the concept, so he needed to

⁴¹ Allegheny Power website, Rates and Tariffs page,
<http://www.alleghenypower.com/Tariffs/Retail%20Tariff%20Home.asp>.

⁴² “New York State Standardized Interconnection Requirements and Application Process for New Distributed Generation 2 MW or Less Connected in Parallel with Utility Distribution Systems”, New York State Public Service Commission, September 2005.

discuss the project with some other people. He never replied or responded to any further emails or phone calls.

Discussions with the digester owners have shown that they have equal difficulty reaching any person with sufficient knowledge to answer questions. In several cases, the farmers have said that it has taken up to nine months to resolve issues and answer questions. The farmers felt that since the utility's purpose is to generate and deliver large amounts of power to customers they are not sufficiently interested in the small amount of power from distributed generation systems like digesters being uploaded onto their grid.

Bob Howatt with the Delaware Public Utility Commission (DE PUC) was called to get their opinion on the concept since they had a different role in the industry than a utility. Mr. Howatt understood the concept and what it will attempt to do. He did not see any reason that it would not be possible for this type of capability to be incorporated into a digester facility.

Calvin Birge with the Pennsylvania Public Utility Commission (PA PUC) ISO did not see any reason that it would not be possible for this type of capability to be incorporated either. However, he pointed out several important considerations. He mentioned that not all utilities purchase peaking capacity from outside vendors. He said that most utilities in Pennsylvania are not required to purchase power, whether it is produced from renewable sources or not. The peaking power however, could be purchased by another entity elsewhere; the local utility would only be used to transmit the power. He felt that the idea of selling peaking power produced on a farm is flawed because of location. Peaking demands typically occur in areas such as large urban centers, where there is a large concentration of people, buildings, and businesses. As a result, peaking plants are located near these areas to minimize the line losses and distribution requirements. He said that utilities outside of these areas, such as the rural areas where farms are located, will likely not have periods where they purchase peaking power. Peaking plants are paid based on both the energy that is produced (\$/kWhr) and a capacity payment (\$/kW). Mr. Birge said that if a peaking agreement was made with a digester farm, it would be unlikely that a capacity payment would be offered.

New York State Electric and Gas Corporation (NYSEG) is the electric utility for the four New York farms that were interviewed. Jim Harvilla from the NYSEG research and development department was called to discuss this project and concept. The propane assisted biodigester fits into the type of forward-looking project that the R&D group investigates for potential deployment. Mr. Harvilla pointed out that NYSEG and Rochester Gas & Electric (RGE) are essentially the same company and that 60% of New York Farms are in their combined coverage area.

Mr. Harvilla said that NYSEG in particular, and utilities in general, pay customers their net meter excess energy payments once per year based on their annual energy usage. He said that this is done because the calculations and accounting for each payment, for each check with relatively small dollar amounts, requires a large amount of labor and is cost prohibitive.

He said that payments will continue to be made annually unless the utility is required by law to reimburse the farms more frequently. Thus, maintaining a constant power output is not necessary or important, so augmenting the fuel stream with low blend levels of propane would not provide additional gains. This would still be the case even if the payments were made monthly in line with the farm's billing cycle. Mr. Harvilla agreed that using propane (or any fuel that was a cost to the farm) at low-blend levels to stabilize the power instantaneous power production was not a good application because of the low payback to the farms for excess net metered energy production. He said that the benefit of a net metering agreement is that the utilities are obligated to purchase all renewable power (such as biomass derived) to satisfy renewable portfolio standard requirements. Whether the addition of propane (or any other non-renewable fuel) would invalidate the power, or would cause other issues with the utility being required to accept the power, is not known.

Mr. Harvilla understood the reasons for potentially adding peaking power generation capability to the farm digester system. He mentioned that NYSEG has investigated this type of system using natural gas. There are several reasons that they have not pursued the idea further:

- Location of power – This reason agrees with Mr. Birge from the PA PUC. Peak energy demand comes from areas with a high concentration of people and business, i.e. urban or nearby suburban areas, not from rural areas. Farms are typically located in rural areas. Peaking plants are located nearby these dense population areas to minimize the transmission distance and logistics. Farm-based peaking power will likely be too far from where it would be used.
- Amount of power – Mr. Harvilla said that the small amount of power at each farm limits their usefulness to offset a peak power demand. Aggregation of peaking power from several farms to increase the available power was also discussed. He said this would improve the viability, but the amount of power will still be very small for a utility and it increases the logistics needed to route the power.
- Purchasing method and payment - There is no legal requirement for utilities in New York to purchase peak power from digesters, other renewable sources, or anyone else.

Most importantly, since NYSEG/RGE is a natural gas and electric utility, it is interested in selling more natural gas and electricity, so accepting power (net meter or peak) produced by propane would most likely not be approved by the company since propane is a competing fuel. This is likely the case for other utilities that have both electric and natural gas, as is common. However, the peaking capacity available from digester farms may be more appealing as the peaking power reserves are depleted. Information from the Federal Energy Regulatory Commission (FERC) on PJM, using PJM data regarding the summer generation capacity, peak demand, and reserves, shows that the percentage of reserve margin (generating capacity minus peak demand) has decreased each year, from 2004 (28,363MW, 36%) to 2005 (33,188 MW, 25%) to 2006 (19,990 MW, 14%). New York is not a part of PJM, but if it is not in the same state, over time the same conditions may appear. The peak summer demand

increased by 8.1% from 2005 to 2006⁴³. This steep decline in peak capacity reserves may make the PJM and the utilities in its territory consider using distributed generation reserves such as anaerobic digesters on farms. However, the issues discussed above regarding the amount of power and the location of the power may make the point moot.

⁴³ Federal Energy Regulatory Commission webpage “PJM Electric Market: Overview and Focal Points”, <http://www.ferc.gov/market-oversight/mkt-electric/pjm/2007/archives/06-2007-elec-pjm-archive.pdf>.

Section 6: Economic Analysis

When the project began, it was believed that a thorough understanding of digester systems operation, efficiency, gas production, generator reserve capacity, and other detailed information was necessary to properly characterize the system and to perform an economic analysis of the concept. However, as the research progressed, it was clear that the concept really focuses on the generator(s) and how it is used. Therefore the available reserve capacity and the generator capacities are the only important variables for determining the energy production and financial impact on the farm. The project goal was to determine the potential for improving the economics and revenue for the farm as well as increasing propane sales. As a result, it was determined that the economic analysis should focus on the differences between a standard digester facility and one that uses propane augmentation.

The following sections discuss how various parameters and values used in the model were determined.

Section 6.1: Fuel Related Genset Power Differences

Natural gas and propane versions of genset engines typically have the same power rating. GE Jenbacher derates the power output of their gensets operating on biogas by using the methane content percentage (60-70%). To be conservative with the estimates, 60% methane was used for the calculations. Thus, a biogas engine produces 60% of the power of a natural gas engine. The converse way of describing this is that a genset will produce 2/3 (67%) more power when fueled with propane.

Section 6.2: Propane Genset Cost Estimates

A typical average biogas generator power rating was in the 100-150kW range. The power would be approximately 160-250kW when fueled with propane. The comments from the utility contacts show that the higher the power, the more interested they may be in using digester farms as a peak period distributed generation resource. Whether installing an additional 100kW, 150kW, or even a 300kW generator will make the concept more interesting to them is unknown. For the purposes of this analysis, a 150kW propane generator will be considered.

The appropriate Waukesha Engine model in this power range is the F11GSID which produces between 115kW and 150kW at different engine speeds. This is Waukesha's smallest genset and would have been selected if 100kW was the power target. The Eastern Region Sales Manager estimated that a complete genset including the cooling and utility interconnection hardware would cost \$140,000³⁵.

Cummins Power Systems was called for a similar price estimate. The sales representative could not give an exact cost estimate because some critical site specific and system design information was not available. He was able to provide a ballpark estimate for a 100kW

(\$25,000) and 150kW (\$41,000) generator. This cost does not include the interconnection hardware, which he suggested could cost between \$20,000 and \$100,000⁴⁴.

The upper end of this range closely matches the estimate from Waukesha Engine. However, the lower end estimate from Cummins of approximately \$61,000 may also be accurate because the farm already has the interconnection hardware for the current genset. Assuming a lower limit of \$70,000 (half of the Waukesha estimate) gives some leeway for upgrades to the existing interconnection hardware.

Section 6.3: Propane Genset Fuel Usage

Section 3.3 discussed the propane augmentation options. One conclusion was that it was not advantageous to blend propane and biogas together for power production stabilization. Therefore, the gensets will be operating on 100% propane. Also, since the propane is used in most cases to produce peaking power, the engine will be operating at 100% load.

The fuel use rates for several Caterpillar gensets in the 85kW-150kW range that can be fueled with propane were located using product datasheets found on the Caterpillar website (<http://www.cat.com/cda/components/fullArticle/?m=39280&x=7&id=215797&languageId=7>).

The information on these engines was determined for natural gas fueled versions, so the fuel use rates were converted to propane equivalents. Fuel heating capacity, btu/scf and btu/gallon, from the U.S. Department of Energy, Energy Efficiency and Renewable Energy (U.S. DOE EERE) (<http://www.eere.energy.gov/afdc/pdfs/fueltable.pdf>) and from the National Propane Gas Association were used. It was assumed that the engine efficiency operating on natural gas and propane is the same. This seems to be a fair assumption since, as mentioned in Section 5.1, the natural gas and propane versions of these engines are rated for the same power. A table summary of the calculations are shown below in Figure 13.

Manuf.	Model	Contin- uous Power Rating (NG) (kW)	Natural Gas Use at 100% Load		Propane Equivalent Fuel Use						
			Total (SCF/hr)	Specific [(SCF/hr) /kW]	Natural Gas Energy Content (btu/scf)	Propane Energy Content (btu/scf)	Ratio	Propane Heating Value (btu/gallon)	Propane Use at 100% Load		
									Total (gph)	Specific (gph/kW)	
Caterpillar	G100F3	85	1,068	12.565	1,021	2,516	0.4058	88,024	12.388	0.1457	
Caterpillar	G3406	150	1,912	12.747	1,021	2,516	0.4058	88,024	22.178	0.1479	
Caterpillar	G125G1	114	1,375	12.061	1,021	2,516	0.4058	88,024	15.949	0.1399	
Caterpillar	G150G1	134	1,621	12.061	1,021	2,516	0.4058	88,024	18.802	0.1399	
Average				12.358	Average				0.1433		

Figure 13: Propane Genset Fuel Usage Calculation Summary

Section 6.4: Propane Prices

Propane suppliers near existing digester farms were called for current pricing. At the time, the expected annual usage had not yet been estimated. Pricing for annual usage between 1,001 and 3,000 gallons was quoted (Figure 14).

State	Company	Phone Number	Nearby Digester Farm	Price (\$/gal)
NY	Suburban Propane	607-753-8248	New Hope View Farm	\$2.649
NY	Suburban Propane	585-343-5522	Emerling Farm	\$2.199
NY	Suburban Propane	315-255-3301	Patterson	\$1.999
NY	Suburban Propane	607-642-8473	A.A. Dairy	\$2.599
PA	Suburban Propane	717-334-6791	Mason Dixon Farm	\$1.990
PA	Suburban Propane	570-524-4456	Schrack Farm	\$1.990
PA	Suburban Propane	814-445-7929	Dovan Farm	\$1.950
Average Price				\$2.197

Figure 14: Propane Price Survey Results (May 15, 2007)

Judging from petroleum prices over the past several years, the average of approximately \$2 per gallon is likely the lowest that propane will be in the future. Therefore for the analysis, a low price (\$2/gallon), medium price (\$3), and high price (\$4) case were selected. The medium and high price cases were selected to provide a range of results. The high case represents a 100% increase, which would be significant.

Section 6.5: Peak Power Purchase Rates

It was reported earlier that peak power purchase values in the range of \$0.75-\$1/kWhr have been paid in the past. No reference backing this up was located, and no reference was found to provide a better estimate. To be much more conservative, three lower peak power rates will be used: \$0.25/kWh, \$0.50/kWh, and \$0.75/kWh. This will provide a more realistic view of the potential for peak power sales since it seems that the utilities are not sufficiently interested to offer very high rates.

Section 6.6: Propane Augmentation Cases

Five cases were identified for further analysis to determine their economic viability. The cases are described below and are summarized in Table 2 (repeated Table 1 for convenience). It was assumed that the digester currently has only one generator, since that was the most common situation. Many farms mentioned that they flare excess gas, so it is also assumed for cases 4 and 5 that there is sufficient biogas to fuel an additional generator. So using the previously wasted excess gas to produce electricity will provide the farms with all of the potential returns for their investment in both the digester system and the additional genset.

- **Case 1** - Uses only the existing generator, but switches to 100% propane for consistent power production.
- **Case 2** - Uses only the existing generator, but switches to 100% propane for peak power production (approximated at 5% of annual hours).
- **Case 3** – Uses the existing generator fueled only on biogas producing net metered power, as is currently being done. An additional propane peaking generator is added to operate only during peak demand periods. The added benefit of avoiding the monthly demand charge by having one generator operating while servicing the other generator is factored into the calculation.
- **Case 4** - Uses the existing generator fueled only on biogas producing net metered power all year. An additional propane peaking generator is added to operate on biogas for 95% of the year and on propane for the remaining 5% of the year during peak demand periods.
- **Case 5** - Uses the existing generator fueled only on biogas producing net metered power for 95% of the year and on propane for the remaining 5% of the year during peak demand periods. An additional generator is added that operates just as the primary generator does; on biogas for 95% of the year and on propane for the remaining 5% of the year during peak demand periods.

Table 2: Summary of Propane Augmentation Cases

Case	Current Generator	Additional Generator
1	Biogas (98%) + propane (2%)	n/a
2	Biogas (95%) + propane (5%)	n/a
3	Biogas (100%)	Propane (5%)
4	Biogas (100%)	Biogas (95%) + propane (5%)
5	Biogas (95%) + propane (5%)	Biogas (95%) + propane (5%)

Section 6.7: Other Important Model Parameters and Assumptions

- It is assumed that the original digester generator was able to produce sufficient electricity to offset the farm’s utility purchases. Thus, all additional power generated by biogas in the cases that install an additional generator will be excess net metered power, where the payback rate is lower than for the avoided utility costs.
- The model accounts for the power output difference between biogas and propane for cases where one engine is fueled on both fuels for some part of the year.
- The biogas genset maintenance costs are included and estimated based on \$0.02/kWh. Several sources have used values between \$0.015 and \$0.02; the higher estimate was used to give a more realistic value since the generator sizes are comparatively small^{11, 32,45,46}. Due to the higher engine output on propane, the

⁴⁵ Biogas Direct website, <http://www.biogas-direct.com/b304.htm>.

maintenance costs are estimated to be higher when operating on propane, which may or may not be the case. This fact, however, only adds between \$263/year to \$1,052/year, which is not miniscule, but is very small compared to the overall operating costs, so will not significantly affect the cost calculations.

- Net metering rates have a low and high case. The low case represents the lowest value found during the farm interviews, \$0.0275/kWh (Mason Dixon Farm, Pennsylvania¹²). The high case of \$0.085/kWhr is for Emerling Farm in New York³¹.
- Demand charges for Emerling Farm ranged from \$500 to \$1,800 per month³¹. Patterson Farm also mentioned they pay a demand charge, but said that they were not charged every month³². The demand charge goes to zero when there is a second generator because then at least one generator is operating at all times.
- Peak power payback rates were estimated for low (\$0.25/kWh), medium (\$0.50/kWh), and high (\$0.75/kWh) cases.
- The payback calculations do not account for equipment purchase financing.
- The cost to rebuild the genset engine was not included.

Figure 15 shows an example of the cost model input screen.

Section 6.8: Analysis

The payback period calculation, i.e. the amount of time necessary for the savings and additional income to equate to the total of the initial capital investment, additional maintenance costs, and additional fuel costs, will determine the economic feasibility of the various cases for the propane assisted biodigester concept. The shorter the payback period the better, because once the initial investment is paid off there is a larger annual income to the farm and that income will continue for a larger percentage of the useful life for the gensets.

For this analysis, there are:

- Two costs for the additional 150kW genset (\$70,000 and \$140,000)
- Two net metering rates (\$0.0275/kWh [low] and \$0.085/kWh [high])
- Three peaking power rates (\$0.25/kWh [low], \$0.50/kWh [medium], and \$0.75/kWh [high])
- Three propane costs per gallon (\$2 [low], \$3 [medium], and \$4 [high])

This results in a total of 36 permutations. In addition, there are five proposed cases for each permutation, or a total of 180 permutations. To make the analysis clear, each case will be discussed individually. The costs are discussed on an incremental basis, i.e. costs and income, above what the baseline biodigester would have had.

⁴⁶ Charles Ross and James Walsh "Handbook of Biogas Utilization", USDOE, Southeastern Regional Biomass Energy Program: Muscle Shoals Alabama, 1996.

**Propane Biodigester Model
 Constants and Baseline Assumptions**

6/14/2007

Genset Performance Characteristics		Unit or source
Power from genset on biogas	90	kW
Power factor for genset on propane	1.667	versus biogas power
Power from genset on propane	150	kW
Propane fuel use at max load	21.50	gal/hour
Biogas fuel use at max load	2	gal/hour

Cost Characteristics for Gensets		
Propane genset price	\$70,000	manufacturer
Incremental cost for dual-fuel genset	\$4,000	vs propane price
Total cost of dual-fuel genset	\$70,000	no
Total hours in year	8,760	per year
Genset maintenance cost	\$0.02	per kWh
Monthly demand charge	\$500.00	\$

Electricity Characteristics		
Net metering rates	\$0.028	per kWh (low)
	\$0.085	per kWh (high)
Peaking power rates	\$0.25	per kWh (low)
	\$0.50	per kWh (medium)
	\$0.75	per kWh (high)

Propane Costs		
Propane Costs	\$2	per gallon (low)
	\$3	per gallon (medium)
	\$4	per gallon (high)

Choice of Variables for Cases		
Net metering rate for calcs	\$0.0275	low
Peaking power rate for calcs	\$0.25	low
Propane Costs for calcs	\$2	low

Figure 15: Example Cost Model Input Screen

Case 1: Uses only the existing generator, but blends in a small amount of propane to stabilize power production

For this case, propane is added only to stabilize the power production. The base case did not include the costs for adding a dual-fuel fuel system. It was not possible to determine exactly

what amount of propane this would correlate to, so it was assumed that 2% of the annual energy produced used propane fuel. The power that is produced is sold back at the same net metering rate as biogas. This use was discounted for several reasons in the text, but the economic calculations were done to verify the logic. The cost effectiveness of this case is straightforward since no additional hardware (genset, interconnection hardware, etc.) is required. Therefore, the economic viability is determined simply by whether the additional income (additional net metered power sales) warrants the additional expense (propane fuel, additional engine maintenance). Figures 16 and 17 provide a summary of the findings that reinforce the earlier belief that propane augmentation for power stabilization is not economically sound. Figure 16 presents the results matrix for each of the case permutations of propane cost (low, medium, and high) and net meter rate (low and high). These values were used in the cost model to determine the annual cost (fuel, maintenance, etc.) and the annual income from net metered energy sales. The value of the net meter energy sales assumes that all of the energy is converted into profit. In reality, the produced power will offset the farm's utility bill, so it likely to have a much higher rate (\$/kWhr) than is available through net metered energy sales. However, since each farm uses a different amount of energy, it was assumed that all of the energy is sold at the net meter rate for excess power. The profitability is determined by the amount of the annual net income. If there is a negative net income (i.e. a loss) the case is not profitable.

As shown in Figure 17, none of the cases were profitable; all resulted in a significant annual loss. The results would have been worse if the dual-fuel system incremental cost was included. The next step was to calculate the rate (\$/kWh) that is necessary to break even (Figure 18). The break even rate depends on the cost of the propane and ranged from \$0.307/kWh to \$0.593/kWh. These rates are much higher than any net meter agreement rates and are instead in the range being considered for peak power generation, so this case is not viable.

Propane Cost	Net Meter Rate		Annual Cost	Annual Income	Annual Net Income	Profit-able	Rate Required for Payback	LP Sales (gal)
	Level	Rate (\$/kWh)						
\$2	High	0.0850	\$ 8,060	\$ 2,234	\$ (5,826)	No	\$ 0.307	3,767
\$3	High	0.0850	\$ 11,827	\$ 2,234	\$ (9,593)	No	\$ 0.450	3,767
\$4	High	0.0850	\$ 15,594	\$ 2,234	\$ (13,361)	No	\$ 0.593	3,767
\$2	Low	0.0275	\$ 8,060	\$ 723	\$ (7,337)	No	\$ 0.307	3,767
\$3	Low	0.0275	\$ 11,827	\$ 723	\$ (11,104)	No	\$ 0.450	3,767
\$4	Low	0.0275	\$ 15,594	\$ 723	\$ (14,872)	No	\$ 0.593	3,767

Figure 16: Case 1 Incremental Cost Summary

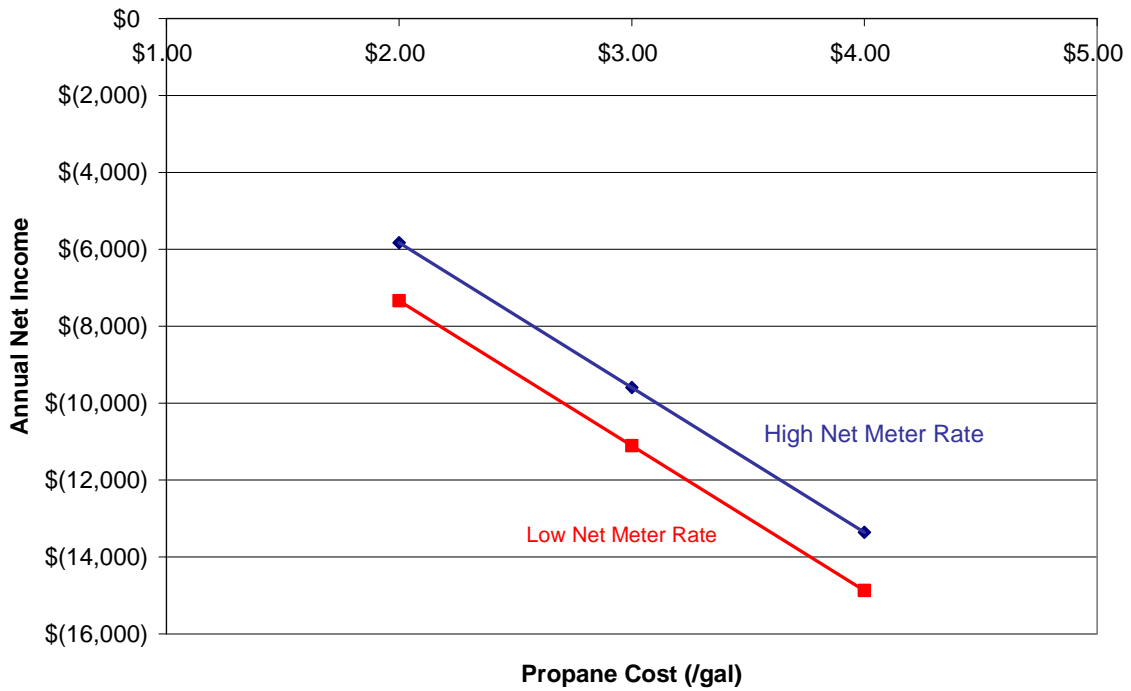


Figure 17: Case 1 Economic Viability

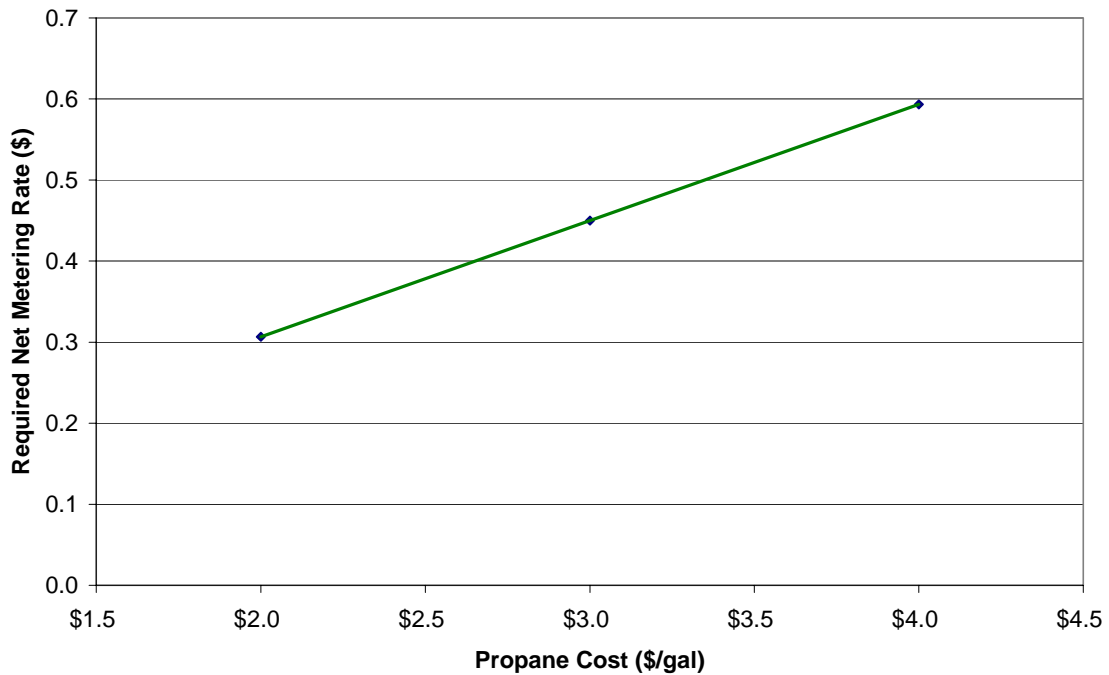


Figure 18: Utility Buyback Rate Required to Break Even

Case 2 - Uses only the existing generator, but switches to 100% propane for peak power production (approximated at 5% of annual hours).

For this case, propane is used for 5% of the annual hours in the existing generator to produce peaking power. The benefit of this case is that it can be implemented using the existing hardware. The cost effectiveness of this case is straightforward since no additional hardware (genset, interconnection hardware, etc.) is required. Therefore, the economic viability is determined simply by whether the additional income (additional peak power sales) warrants the additional expense (propane fuel, additional engine maintenance).

Figures 19 and 20 show the case results in a similar fashion to Case 1..This case has merit, but is tied primarily to the peak power rate (\$/kWh). The \$0.25/kWh case is never profitable in the \$2-\$4 propane price range. Lower propane prices would make it profitable, but prices are likely not going to decrease. All but one of the medium and high payback rate cases were profitable. As expected, the profitability improves as the peak power rate increases along with low fuel prices. Regardless of the cost effectiveness, this case results in an estimated additional sale of 9,418 gallons of propane.

Propane Cost	Peak Power Rate		Annual Cost	Annual Income	Annual Net Income	Profit-able	LP Sales (gal)
	Level	Rate (\$/kWh)					
\$2	High	\$0.75	\$ 20,150	\$ 49,275	\$ 29,125.10	Yes	9,418
\$3	High	\$0.75	\$ 29,568	\$ 49,275	\$ 19,707.15	Yes	9,418
\$4	High	\$0.75	\$ 38,986	\$ 49,275	\$ 10,289.20	Yes	9,418
\$2	Medium	\$0.50	\$ 20,150	\$ 32,850	\$ 12,700.10	Yes	9,418
\$3	Medium	\$0.50	\$ 29,568	\$ 32,850	\$ 3,282.15	Yes	9,418
\$4	Medium	\$0.50	\$ 38,986	\$ 32,850	\$ (6,135.80)	No	9,418
\$2	Low	\$0.25	\$ 20,150	\$ 16,425	\$ (3,724.90)	No	9,418
\$3	Low	\$0.25	\$ 29,568	\$ 16,425	\$ (13,142.85)	No	9,418
\$4	Low	\$0.25	\$ 38,986	\$ 16,425	\$ (22,560.80)	No	9,418

Figure 19: Case 2 Incremental Cost Summary

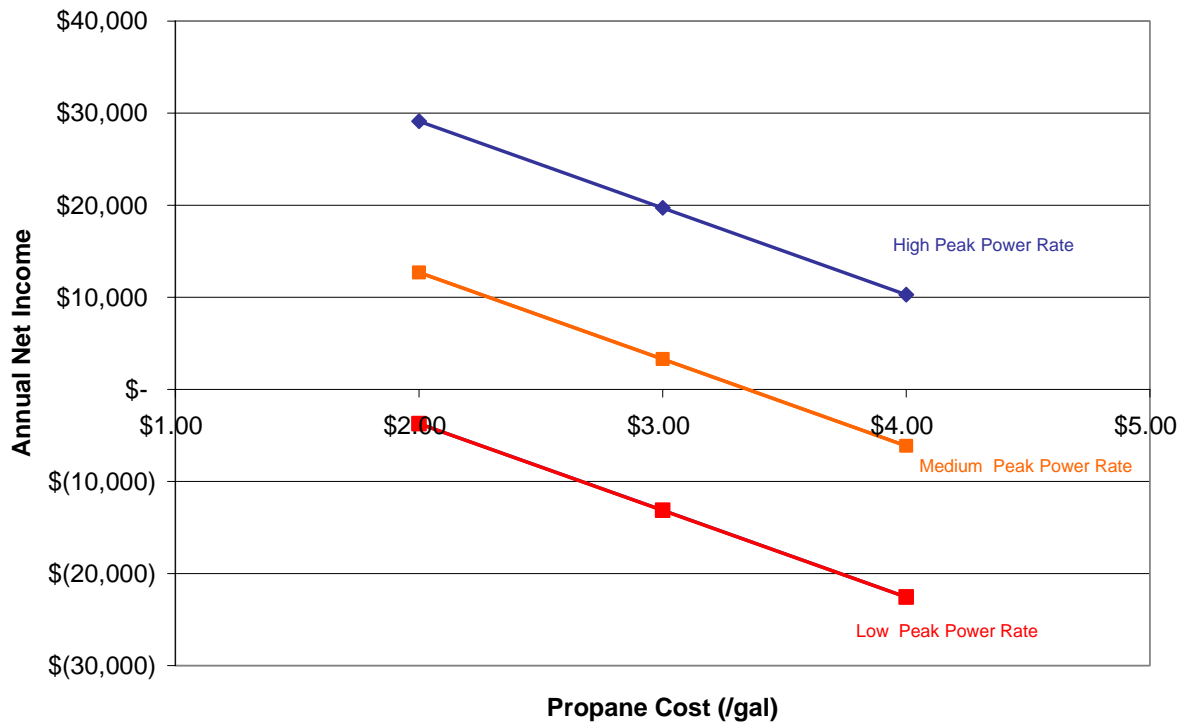


Figure 20: Case 2 Economic Viability

Case 3 – Uses the existing generator fueled only on biogas producing net metered power, as is currently being done. An additional propane peaking generator is added to operate only during peak demand periods. The added benefit of avoiding the monthly demand charge by having one generator operating while servicing the other generator is be factored into the calculation.

For this case, an additional propane genset is installed and is used solely to produce peaking power for 5% of the annual hours and during periods when the primary engine is being serviced. It remains turned off for the remaining 95% of the time. The cost effectiveness of this case is more complicated because of the additional capital cost required to purchase, install, and operate the genset. This difference required a different method to evaluate the cost effectiveness. In Cases 1 and 2, a positive annual income indicated the case would be worthwhile. However in this case, the equipment purchases (generator, interconnection hardware, utility hardware upgrades, etc.) must be paid back in a reasonable period. Unfortunately, the length of an acceptable payback period is not a distinct value that can be calculated. Neither the interviews nor the literature review revealed a universally acceptable value. Due to the large initial expense for the digester system the useful lifetime would likely be twenty years or more. As an example, the Mason Dixon digester was installed in 1978 and is still operating¹². Since the payback period was not determined, values were chosen based

on what would logically seem to be a reasonable timeframe to pay back an investment. For example, a payback of five years or less was considered good.

The calculations for this case are essentially the same as for Cases 1 and 2. The main difference is that the profitability is described here by the payback period since the additional capital cost of the additional genset must be factored into the economic viability. The shorter the payback period the better because: the initial investment is paid off quickly, the annual profit from the additional hardware is higher, and the higher annual profit results in larger savings over the lifetime. The initial cost estimates for the generator had a significant range, so the calculations were done for both costs (\$70,000 and \$140,000). Figure 21 presents the results in tabular form, with the \$70,000 capital cost cases presented at the top.

The legend terminology, e.g. “\$70K – High”, refers to the case where the generator costs \$70,000 and the high peak power payback rate (\$0.75/kWh) is used. Figure 22 presents the profitability of each case, based on the payback period, in graphical form. Negative payback periods are not plotted, since this reflects that the corresponding scenarios results in an annual net loss, thus none of the low peak power rate cases were plotted.

As with Case 2, none of the cases with the low peak power rate (\$0.25/kWh) were profitable. All of the medium payback rate (\$0.50/kWh) cases except one were either not profitable, or would have a payback longer than ten years. The only medium payback rate case that was marginally worthwhile was the one with the lowest propane cost (\$2/gal). This is positive, but given the trends for volatile and increasing fuel prices, it would not be recommended for a farm to agree to a peak power purchase agreement at \$0.50/kWh.

Genset Cost	Propane Cost	Peak Power Rate		Annual Cost	Annual Income	Annual Net Income	Payback Period (yrs)	Profitable	Propane Sales (gal)
		Level	Rate (\$/kWh)						
70,000	\$2	High	\$0.75	\$ 20,150	\$ 49,275	\$ 29,125	2.4	Good	9,418
70,000	\$3	High	\$0.75	\$ 29,568	\$ 49,275	\$ 19,707	3.6	Good	9,418
70,000	\$4	High	\$0.75	\$ 38,986	\$ 49,275	\$ 10,289	6.8	Acceptable	9,418
70,000	\$2	Medium	\$0.50	\$ 20,150	\$ 32,850	\$ 12,700	5.5	Acceptable	9,418
70,000	\$3	Medium	\$0.50	\$ 29,568	\$ 32,850	\$ 3,282	21.3	Too Long	9,418
70,000	\$4	Medium	\$0.50	\$ 38,986	\$ 32,850	\$ (6,136)	-11.4	No	9,418
70,000	\$2	Low	\$0.25	\$ 20,150	\$ 16,425	\$ (3,725)	-18.8	No	9,418
70,000	\$3	Low	\$0.25	\$ 29,568	\$ 16,425	\$ (13,143)	-5.3	No	9,418
70,000	\$4	Low	\$0.25	\$ 38,986	\$ 16,425	\$ (22,561)	-3.1	No	9,418
140,000	\$2	High	\$0.75	\$ 20,150	\$ 49,275	\$ 29,125	4.8	Good	9,418
140,000	\$3	High	\$0.75	\$ 29,568	\$ 49,275	\$ 19,707	7.1	Acceptable	9,418
140,000	\$4	High	\$0.75	\$ 38,986	\$ 49,275	\$ 10,289	13.6	Too Long	9,418
140,000	\$2	Medium	\$0.50	\$ 20,150	\$ 32,850	\$ 12,700	11.0	Too Long	9,418
140,000	\$3	Medium	\$0.50	\$ 29,568	\$ 32,850	\$ 3,282	42.7	Too Long	9,418
140,000	\$4	Medium	\$0.50	\$ 38,986	\$ 32,850	\$ (6,136)	-22.8	No	9,418
140,000	\$2	Low	\$0.25	\$ 20,150	\$ 16,425	\$ (3,725)	-37.6	No	9,418
140,000	\$3	Low	\$0.25	\$ 29,568	\$ 16,425	\$ (13,143)	-10.7	No	9,418
140,000	\$4	Low	\$0.25	\$ 38,986	\$ 16,425	\$ (22,561)	-6.2	No	9,418

Figure 21: Case 3 Incremental Cost Summary

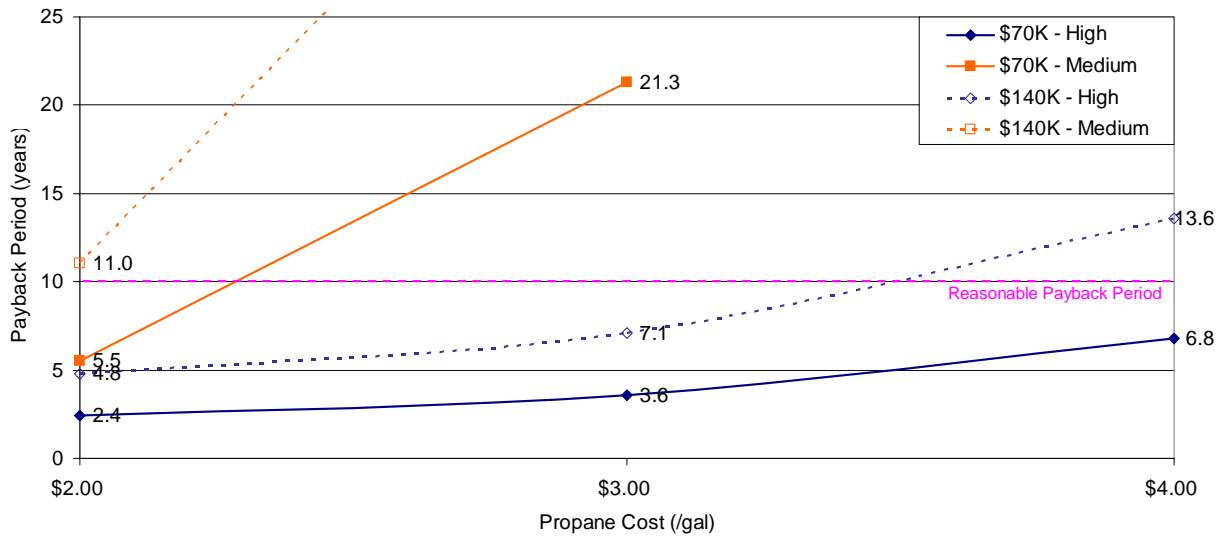


Figure 22: Case 3 Economic Viability

The high peak power rate (\$0.75/kWh) results are much more encouraging. All of the cases at the low generator cost (solid line) have good payback periods. Even when the generator cost is doubled (dashed line) the results show favorable payback up to the \$3/gallon fuel price. This shows that there is an economic case if the farm’s electric utility is willing to offer a peak power agreement at this rate. Regardless of the cost effectiveness, this case results in an estimated additional sale of 9,418 gallons of propane. This is the same as for the previous case, since propane is still only being used in one generator for 5% of the year.

Case 4 - Uses the existing generator fueled only on biogas producing net metered power all year. An additional propane peaking generator is added to operate on biogas for 95% of the year and on propane for the remaining 5% of the year during peak demand periods.

Figures 23 and 25 present the results in tabular form. Figures 24 and 26 present the results in graphical form. Figures 23 and 24 use the low net meter rate (\$0.0275/kWh) for biogas produced power, while Figures 25 and 26 use the high net meter rate (\$0.085/kWh). The terminology, (e.g. “\$70K – High”), refers to the case where the generator costs (e.g. \$70,000) and the high peak power payback rate (e.g. \$0.75/kWh) are used. Other cases follow the same convention.

Genset Cost	Propane Cost	Peak Power Rate		Annual Cost	Annual Income	Annual Net Income	Payback Period (yrs)	Profitable	Propane Sales (gal)
		Level	Rate (\$/kWh)						
70,000	\$2	High	\$0.75	\$ 35,127	\$ 69,868	\$ 34,741	2.0	Good	9,418
70,000	\$3	High	\$0.75	\$ 44,544	\$ 69,868	\$ 25,323	2.8	Good	9,418
70,000	\$4	High	\$0.75	\$ 53,962	\$ 69,868	\$ 15,905	4.4	Good	9,418
70,000	\$2	Medium	\$0.50	\$ 35,127	\$ 53,443	\$ 18,316	3.8	Good	9,418
70,000	\$3	Medium	\$0.50	\$ 44,544	\$ 53,443	\$ 8,898	7.9	Acceptable	9,418
70,000	\$4	Medium	\$0.50	\$ 53,962	\$ 53,443	\$ (520)	-134.7	No	9,418
70,000	\$2	Low	\$0.25	\$ 35,127	\$ 37,018	\$ 1,891	37.0	Too Long	9,418
70,000	\$3	Low	\$0.25	\$ 44,544	\$ 37,018	\$ (7,527)	-9.3	No	9,418
70,000	\$4	Low	\$0.25	\$ 53,962	\$ 37,018	\$ (16,945)	-4.1	No	9,418
140,000	\$2	High	\$0.75	\$ 35,127	\$ 69,868	\$ 34,741	4.0	Good	9,418
140,000	\$3	High	\$0.75	\$ 44,544	\$ 69,868	\$ 25,323	5.5	Acceptable	9,418
140,000	\$4	High	\$0.75	\$ 53,962	\$ 69,868	\$ 15,905	8.8	Acceptable	9,418
140,000	\$2	Medium	\$0.50	\$ 35,127	\$ 53,443	\$ 18,316	7.6	Acceptable	9,418
140,000	\$3	Medium	\$0.50	\$ 44,544	\$ 53,443	\$ 8,898	15.7	Too Long	9,418
140,000	\$4	Medium	\$0.50	\$ 53,962	\$ 53,443	\$ (520)	-269.5	No	9,418
140,000	\$2	Low	\$0.25	\$ 35,127	\$ 37,018	\$ 1,891	74.0	Too Long	9,418
140,000	\$3	Low	\$0.25	\$ 44,544	\$ 37,018	\$ (7,527)	-18.6	No	9,418
140,000	\$4	Low	\$0.25	\$ 53,962	\$ 37,018	\$ (16,945)	-8.3	No	9,418

Figure 23: Case 4 (Low Net Meter Rate) Incremental Cost Summary

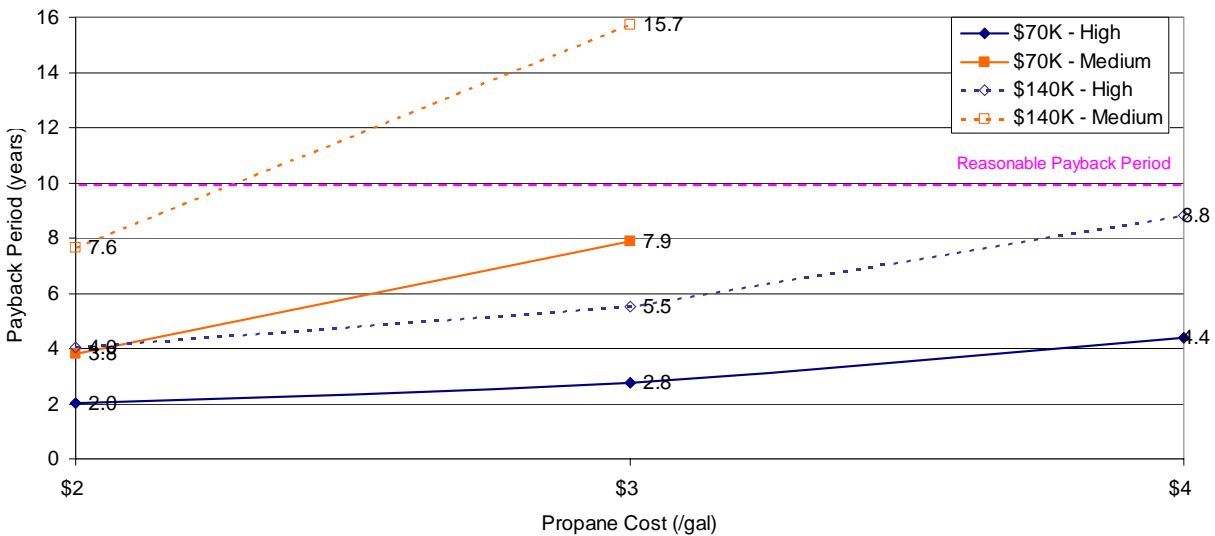


Figure 24: Case 4 (Low Net Meter Rate) Economic Viability

Low Net Meter Rate

This case subset pertains to states such as Pennsylvania where the utilities offer farms a low payback for excess biogas-produced power. The only difference between the low and high generator cost cases is a doubling of the payback period due to the initial capital cost being double. As with the previous cases, none of the low payback rate cases with either the low or high generator cost options are worthwhile (see Figures 23 and 24). Either the cases are not

Genset Cost	Propane Cost	Peak Power Rate		Annual Cost	Annual Income	Annual Net Income	Payback Period (yrs)	Profitable	Propane Sales (gal)
		Level	Rate (\$/kWh)						
70,000	\$2	High	\$0.75	\$ 35,127	\$ 112,926	\$ 77,799	0.9	Good	9,418
70,000	\$3	High	\$0.75	\$ 44,544	\$ 112,926	\$ 68,381	1.0	Good	9,418
70,000	\$4	High	\$0.75	\$ 53,962	\$ 112,926	\$ 58,963	1.2	Good	9,418
70,000	\$2	Medium	\$0.50	\$ 35,127	\$ 96,501	\$ 61,374	1.1	Good	9,418
70,000	\$3	Medium	\$0.50	\$ 44,544	\$ 96,501	\$ 51,956	1.3	Good	9,418
70,000	\$4	Medium	\$0.50	\$ 53,962	\$ 96,501	\$ 42,538	1.6	Good	9,418
70,000	\$2	Low	\$0.25	\$ 35,127	\$ 80,076	\$ 44,949	1.6	Good	9,418
70,000	\$3	Low	\$0.25	\$ 44,544	\$ 80,076	\$ 35,531	2.0	Good	9,418
70,000	\$4	Low	\$0.25	\$ 53,962	\$ 80,076	\$ 26,113	2.7	Good	9,418
140,000	\$2	High	\$0.75	\$ 35,127	\$ 112,926	\$ 77,799	1.8	Good	9,418
140,000	\$3	High	\$0.75	\$ 44,544	\$ 112,926	\$ 68,381	2.0	Good	9,418
140,000	\$4	High	\$0.75	\$ 53,962	\$ 112,926	\$ 58,963	2.4	Good	9,418
140,000	\$2	Medium	\$0.50	\$ 35,127	\$ 96,501	\$ 61,374	2.3	Good	9,418
140,000	\$3	Medium	\$0.50	\$ 44,544	\$ 96,501	\$ 51,956	2.7	Good	9,418
140,000	\$4	Medium	\$0.50	\$ 53,962	\$ 96,501	\$ 42,538	3.3	Good	9,418
140,000	\$2	Low	\$0.25	\$ 35,127	\$ 80,076	\$ 44,949	3.1	Good	9,418
140,000	\$3	Low	\$0.25	\$ 44,544	\$ 80,076	\$ 35,531	3.9	Good	9,418
140,000	\$4	Low	\$0.25	\$ 53,962	\$ 80,076	\$ 26,113	5.4	Acceptable	9,418

Figure 25: Case 4 (High Net Meter Rate) Incremental Cost Summary

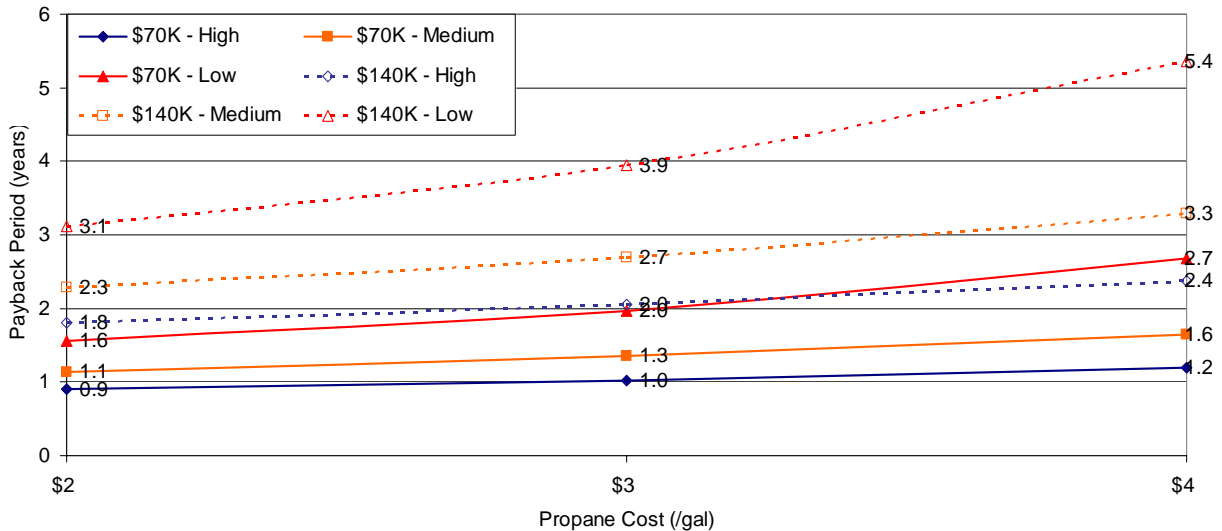


Figure 26: Case 4 (High Net Meter Rate) Economic Viability

profitable, or they require much longer times than are acceptable (27 and 74 years) to reach payback.

The medium payback rate case at the low generator cost is favorable, but only if propane stays below \$4. The high generator cost case at the medium peak power rate is only marginally useful: it reaches an acceptable payback, but only if the propane cost stays below

approximately \$2.25/gallon. All of the high peak power cases reach payback in an acceptable time period. This is encouraging, but again relies on the willingness of the utility to offer a high peak power rate to the farm.

High Net Meter Rate

This case subset pertains to states such as New York where the utilities offer farms a higher payback for excess biogas produced power. The only difference between the low and high generator cost cases is a doubling of the payback period due to the initial capital cost being double. All of the cases were profitable at some acceptable point, which is very encouraging (see Figures 25 and 26). The propane fuel cost has a much smaller impact on the payback calculations since biogas is used for the majority of the annual power being produced with the second generator. Even though propane is only used for 5% of the time, it accounts for approximately 1/3rd of the income from electricity sales. This again relies on the willingness of the utility to offer a high peak power rate to the farm, but the importance is lessened due to the near doubling of the biogas power produced, which the utilities are obliged to purchase.

Regardless of the cost effectiveness, this case results in an estimated additional sale of 9,418 gallons of propane. This is the same as for Cases 2 and 3, because propane is still only being used in one generator for 5% of the year.

Case 5 - Uses the existing generator fueled only on biogas producing net metered power for 95% of the year and on propane for the remaining 5% of the year during peak demand periods. An additional propane peaking generator is added to operate only during peak demand periods.

This case, as with the previous case, a portion of the additional income is from the sale of net metered energy produced from biogas. As a result, low and high net meter rates are shown in a similar fashion to Case 4. Also, as with Cases 3 and 4, the cost of the additional generator was included in the capital costs. The same high and low cost values were used.

Low Net Meter Rate

This case subset pertains to states such as Pennsylvania where the utilities only offer farms a low payback for excess biogas produced power. This case also uses the primary generator to produce peaking power for 5% of the year; as a result, the net metered biogas produced power is reduced by 5%. The only difference between the low and high generator cost cases is a doubling of the payback period due to the initial capital cost being double. As with the previous cases, none of the low payback rate cases with either the low or high generator cost options are profitable (see Figures 27 and 28).

The medium payback rate case at both generator costs is favorable, but only if propane stays at, or below, \$2. Therefore, this case would not be recommended. Case 4 under these conditions was slightly more favorable as a result of a lower percentage of the power being propane powered; Case 5 is more affected by propane pricing. The high generator cost case

Genset Cost	LP Cost	Peak Power Rate		Annual Cost	Annual Income	Annual Net Income	Payback Period (yrs)	Profitable	LP Sales (gal)
		Level	Cost						
70,000	\$2	High	\$0.75	\$ 71,041	\$ 118,059	\$ 47,018	1.5	Good	18,836
70,000	\$3	High	\$0.75	\$ 89,877	\$ 118,059	\$ 28,182	2.5	Good	18,836
70,000	\$4	High	\$0.75	\$ 108,713	\$ 118,059	\$ 9,346	7.5	Acceptable	18,836
70,000	\$2	Medium	\$0.50	\$ 71,041	\$ 85,209	\$ 14,168	4.9	Good	18,836
70,000	\$3	Medium	\$0.50	\$ 89,877	\$ 85,209	\$ (4,668)	-15.0	No	18,836
70,000	\$4	Medium	\$0.50	\$ 108,713	\$ 85,209	\$ (23,504)	-3.0	No	18,836
70,000	\$2	Low	\$0.25	\$ 71,041	\$ 52,359	\$ (18,682)	-3.7	No	18,836
70,000	\$3	Low	\$0.25	\$ 89,877	\$ 52,359	\$ (37,518)	-1.9	No	18,836
70,000	\$4	Low	\$0.25	\$ 108,713	\$ 52,359	\$ (56,354)	-1.2	No	18,836
140,000	\$2	High	\$0.75	\$ 71,041	\$ 118,059	\$ 47,018	3.0	Good	18,836
140,000	\$3	High	\$0.75	\$ 89,877	\$ 118,059	\$ 28,182	5.0	Good	18,836
140,000	\$4	High	\$0.75	\$ 108,713	\$ 118,059	\$ 9,346	15.0	Too Long	18,836
140,000	\$2	Medium	\$0.50	\$ 71,041	\$ 85,209	\$ 14,168	9.9	Acceptable	18,836
140,000	\$3	Medium	\$0.50	\$ 89,877	\$ 85,209	\$ (4,668)	-30.0	No	18,836
140,000	\$4	Medium	\$0.50	\$ 108,713	\$ 85,209	\$ (23,504)	-6.0	No	18,836
140,000	\$2	Low	\$0.25	\$ 71,041	\$ 52,359	\$ (18,682)	-7.5	No	18,836
140,000	\$3	Low	\$0.25	\$ 89,877	\$ 52,359	\$ (37,518)	-3.7	No	18,836
140,000	\$4	Low	\$0.25	\$ 108,713	\$ 52,359	\$ (56,354)	-2.5	No	18,836

Figure 27: Case 5 (Low Net Meter Rate) Incremental Cost Summary

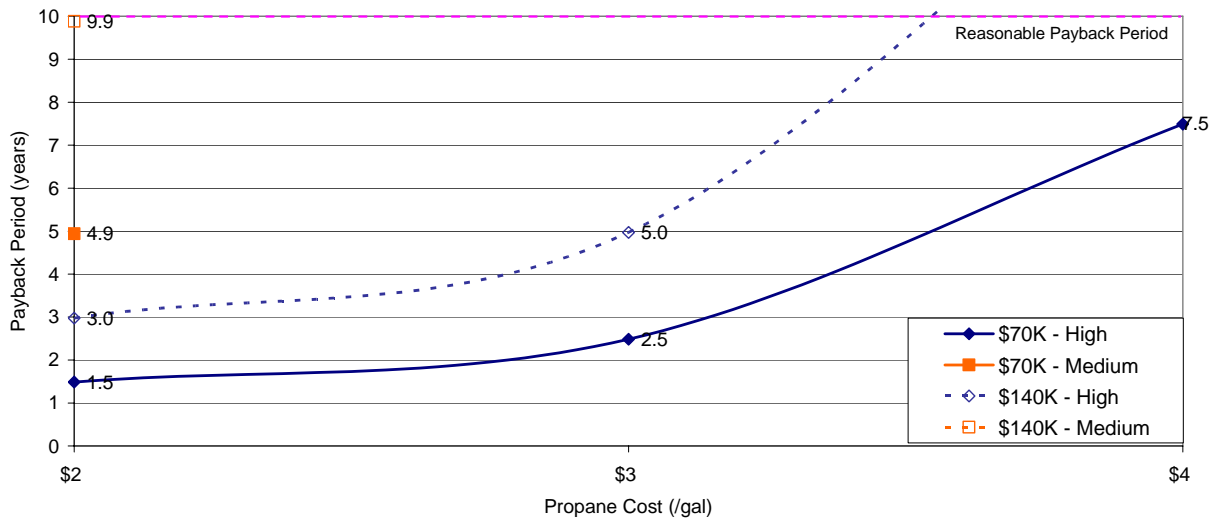


Figure 28: Case 5 (Low Net Meter Rate) Economic Viability

at the medium rate is only marginally useful because it reaches an acceptable payback in just shy of 10 years, but only if the propane cost stays at \$2/gallon. This case, too, would not be recommended. Nearly all of the high peak power cases reach payback in an acceptable time. This is encouraging, but again relies on the willingness of the utility to offer this rate to farms.

Genset Cost	LP Cost	Peak Power Rate		Annual Cost	Annual Income	Annual Net Income	Payback Period (yrs)	Profitable	LP Sales (gal)
		Level	Cost						
70,000	\$2	High	\$0.75	\$ 71,041	\$ 158,851	\$ 87,809	0.8	Good	18,836
70,000	\$3	High	\$0.75	\$ 89,877	\$ 158,851	\$ 68,973	1.0	Good	18,836
70,000	\$4	High	\$0.75	\$ 108,713	\$ 158,851	\$ 50,137	1.4	Good	18,836
70,000	\$2	Medium	\$0.50	\$ 71,041	\$ 126,001	\$ 54,959	1.3	Good	18,836
70,000	\$3	Medium	\$0.50	\$ 89,877	\$ 126,001	\$ 36,123	1.9	Good	18,836
70,000	\$4	Medium	\$0.50	\$ 108,713	\$ 126,001	\$ 17,287	4.0	Good	18,836
70,000	\$2	Low	\$0.25	\$ 71,041	\$ 93,151	\$ 22,109	3.2	Good	18,836
70,000	\$3	Low	\$0.25	\$ 89,877	\$ 93,151	\$ 3,273	21.4	Too Long	18,836
70,000	\$4	Low	\$0.25	\$ 108,713	\$ 93,151	\$ (15,563)	-4.5	No	18,836
140,000	\$2	High	\$0.75	\$ 71,041	\$ 158,851	\$ 87,809	1.6	Good	18,836
140,000	\$3	High	\$0.75	\$ 89,877	\$ 158,851	\$ 68,973	2.0	Good	18,836
140,000	\$4	High	\$0.75	\$ 108,713	\$ 158,851	\$ 50,137	2.8	Good	18,836
140,000	\$2	Medium	\$0.50	\$ 71,041	\$ 126,001	\$ 54,959	2.5	Good	18,836
140,000	\$3	Medium	\$0.50	\$ 89,877	\$ 126,001	\$ 36,123	3.9	Good	18,836
140,000	\$4	Medium	\$0.50	\$ 108,713	\$ 126,001	\$ 17,287	8.1	Acceptable	18,836
140,000	\$2	Low	\$0.25	\$ 71,041	\$ 93,151	\$ 22,109	6.3	Acceptable	18,836
140,000	\$3	Low	\$0.25	\$ 89,877	\$ 93,151	\$ 3,273	42.8	Too Long	18,836
140,000	\$4	Low	\$0.25	\$ 108,713	\$ 93,151	\$ (15,563)	-9.0	No	18,836

Figure 29: Case 5 (High Net Meter Rate) Incremental Cost Summary

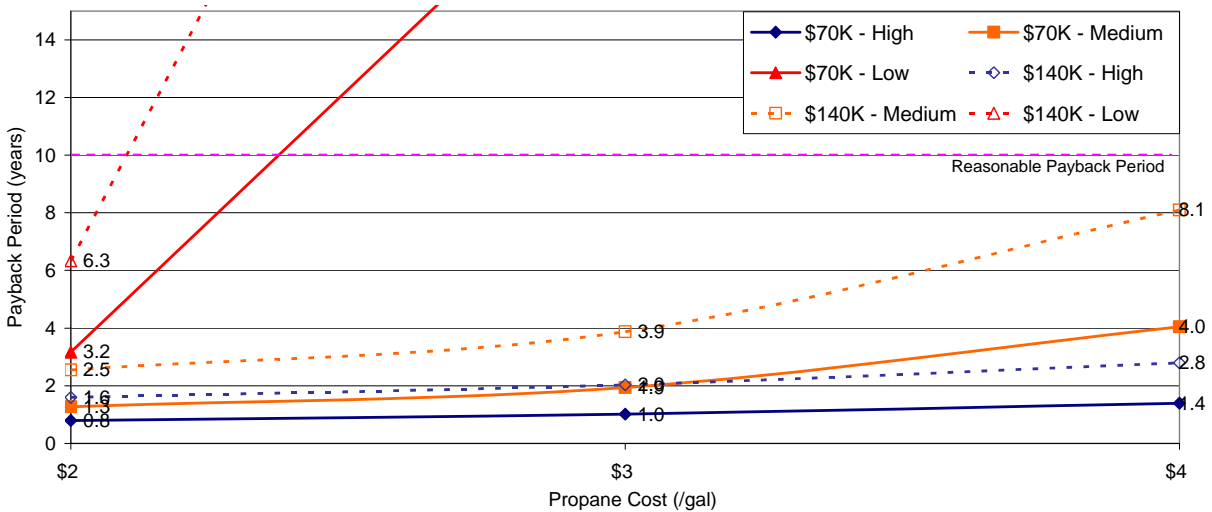


Figure 30: Case 5 (High Net Meter Rate) Economic Viability

High Net Meter Rate

This case subset pertains to states such as New York where the utilities offer farms a higher payback for excess biogas produced power (see Figures 29 and 30). The only difference between the low and high generator cost cases is a doubling of the payback period due to the initial capital cost being double. The low peak power rate cases were only profitable with propane at \$2 per gallon and the payback time quickly increased as fuel price increased. Therefore this case would not be recommended. The propane fuel cost again has more of an effect in this case than in Case 4 because it is used in both generators, Even though propane is only used for 5% of the time in both engines combined, it accounts for approximately 60% of the income from electricity sales. This is encouraging, but relies on the willingness of the utility to offer a high peak power rate to the farm; however, the importance of this is less because of the near doubling of the biogas power produced, which the utilities are obliged to purchase.

Regardless of the cost effectiveness, Case 5 results in an estimated additional sale of 18,836 gallons of propane, which is more than any of the other cases. In this case propane is being used in both generators for 5% of the year.

Section 7: Develop Demonstration Project

Section 7.1 – Interest from Existing Dairy Farms with Digesters

As mentioned earlier, eight dairy farms either with existing anaerobic digester systems installed, or in the process of installing them, in Maryland, Pennsylvania, and New York (Delaware does not have any) were interviewed. This project and the concept of using propane to augment the generator fuel stream were discussed. All of the farms have agreed that adding propane to the fuel stream and the potential electrical interconnection upgrades to their digester system would increase the farm's operational complexity somewhat. However all of the farms are always looking for additional revenue streams to keep the farm profitable since they are always under pressure to reduce milk prices. The ability to utilize existing or upgraded generator(s) and electric utility interconnection hardware to sell peaking power would be worth exploring if it was economically viable. Most of the farms lamented the difficulties they have had with their electric utility to connect their digester to the grid, so they understand that the process and discussions to make this happen will not be short. All of the farms are willing to sign a letter of interest supporting the Phase II demonstration project if it is pursued.

Section 7.2 – Interest from Electric Utilities

Mr. Harvilla (NYSEG) was asked whether he would sign a letter of support (technical support related to utility interconnection and purchase rates, not financial support) for a Phase II concept demonstration project. As previously discussed, NYSEG is involved in energy efficiency and renewable energy projects, including on dairy farms. However, the addition of producing power using propane, a competing fuel, would likely cause the utility to not support a demonstration for this concept. The issues involved with producing and purchasing the small amount of peak power discussed above also would make this difficult to get approval.

NYSEG was the only utility that replied and was willing to discuss the project in detail. The Pennsylvania Public Utilities commission contact, however, agreed with the logistical issues involved with using distant rural sources to supply peak power for urban areas.

Section 7.3 - Funding Opportunities for a Phase II Demonstration Project.

Section 7.3.1: Pennsylvania Department of Environmental Protection

Section 7.3.1.1: Pennsylvania Development Authority Grants

The following text is taken from the Pennsylvania Energy Development Authority (PEDA) grant solicitation: "The Pennsylvania Energy Development Authority (PEDA) is offering grant funding for clean, alternative energy projects in Pennsylvania, and investment in Pennsylvania's

energy sector. PEDA is seeking applications for innovative, advanced energy projects, and for businesses interested in locating or expanding their alternative energy manufacturing or production operations in the Commonwealth. PEDA will consider projects in the following categories. For purposes of this financial assistance, alternative energy projects means projects involving the following types of fuels, technologies or measures: clean, alternative fuels for transportation; solar energy; wind; low-impact hydropower; geothermal; biologically derived methane gas, including landfill gas; biomass; fuel cells; coal-mine methane; waste coal; integrated gasification combined cycle; demand management measures, including recycled energy and energy recovery, energy efficiency and load management. PEDA particularly encourages the development of clean, distributed generation projects to provide backup power for critical public infrastructure.” The underlined text highlights areas where a Phase II demonstration of the propane assisted biodigester concept addresses the grant requirements. PEDA funds are for demonstration/deployment projects, not feasibility studies, which is ideal since the Phase I project being presented in this document covers the concept feasibility. The application deadline was 6/15/2007. However, the program has been funded annually since 2003, so it is anticipated that additional funding will be added for later solicitations.

Weblink – <http://www.depweb.state.pa.us/energy/cwp/view.asp?a=1374&q=483024>.

Section 7.3.1.1: Energy Harvest Grant

This text is taken from the Pennsylvania Energy Harvest Grant solicitation: “The Pennsylvania Energy Harvest Grant is seeking applications for innovative energy deployment projects that also address either: air quality protection or improvement, or, watershed protection or improvement. Pennsylvania Energy Harvest Grants are intended to address the dual concerns of energy and environmental quality. As such, proposals must simultaneously reduce or supplement the use of conventional energy sources and lead to improvements in water or air quality. Projects must demonstrate direct environmental enhancement of watersheds or result in reductions of nitrogen oxides, volatile organic compounds, particulate matter or other toxic air pollutants. Proposals should clearly indicate how environmental quality will be improved and how much energy will be produced or conserved by the project.”

The main element of the project would be propane power generation, so this does not fit well. The argument could be made that adding this element onto the system could improve the system economics to speed the deployment of digesters; however the counter argument could be that additional biogas storage could be installed to fuel the engine during peak energy production.

The application deadline was 6/15/2007; however, it is anticipated that additional funding will be added for later solicitations.

Weblink – <http://www.depweb.state.pa.us/enintech/cwp/view.asp?a=1415&q=504241>

Section 7.3.2: New York State Energy Research Development Authority (NYSERDA)

NYSERDA funding is available through both the typical request for proposal (RFP) process and through specific Program Opportunity Notices (PON). NYSERDA funds projects in all areas (residential, commercial, industrial) to address environmental, energy use, energy security, and other issues. Many dairy farm digester projects in New York have been funded and continue to be monitored (<http://www.chpreliability.com>) by NYSERDA.

Section 7.3.2.1: Phase II Demonstration Relevant PONs

PON 1097 – “Peak-Load Reduction Program”

This PON includes distributed generation and funds at the lesser value of \$150/kW, or 65% of the project cost. This is only available in the ConEd territory and for capacity of ≥ 100 kW. This is a possibility, but none of the New York digesters contacted to date are in the ConEd territory. Funds are available on a first come, first served basis starting March 31, 2008.

Weblink – <http://www.nyserdera.org/Programs/PeakLoad/default.asp?i=PON%201097>

PON 1105 – “Next Generation Emerging Technologies for End-Use Efficiency”

Four million dollars are available over two rounds (Round 2 was due June 2, 2007). A Phase II demonstration project would potentially fit into the Market and Technology Assessment category, with a maximum of \$200K in NYSERDA funds, with a 20% match, or into the Product Development category, with a maximum of \$300K in NYSERDA funds, with a 50% match requirement.

Weblink – <http://www.nyserdera.org/funding/1105pon.pdf>

PON 1118 – “Environmentally Preferred Power Systems Technologies”

This PON includes projects that develop and demonstrate renewable and other environmentally preferred technologies, including distributed generation. \$7.25M is available over two rounds (Round 2 is due October 17, 2007). Phase II would likely fit into the New Product Development category, with a maximum of \$500K in NYSERDA funds, with a 50% match requirement.

Weblink – http://www.nyserdera.org/includes/funding_content_pop.asp?i=PON%201118

Section 8: Study Conclusions

- The initial belief that the digester would mitigate the nutrients in the manure, mainly phosphorous, as a way to improve water quality in the Chesapeake Bay drainage basin was not true. An additional system would have to be installed after the digester exit to reduce phosphorous.
- The farm and dairy cow density in the Mid-Atlantic were identified to determine the best potential locations for a follow-on demonstration project.
- Propane availability was verified in all counties in the Chesapeake Bay drainage basin.
- The technical feasibility of developing and using a dual-fuel (biogas-propane) genset was proven by discussions with biogas engine manufacturers. Unfortunately, due to the challenges of using two fuels with a large energy content difference, the actual or expected power output for both propane and biogas would likely remain the same as a dedicated biogas engine.
 - However, as indicated by several farms operating digesters, in practical applications, dual-fuel biogas/propane engines (operating on either 100% biogas or 100% propane), are currently being used. The farms indicated that output operating on propane is higher than biogas as was initially expected.
- A net metered power purchase agreement is the main economic payback option currently available to farms with digesters.
 - Peak power purchases have never been discussed.
- Discussions with utility contacts show that there are several issues with the ability to use the digester generators on farms to produce peaking power.
 - The power output from a farm is very small compared to a peaking need, so it is likely not large enough to interest the utility in entering into an agreement with a farm for peaking power.
 - The location of the farm is typically far from where the power is needed (rural vs. urban).
 - Utilities are required to purchase power produced from renewable resources such as biogas; however, they are not required to purchase peaking power, regardless of the fuel used to produce it.
 - NYSEG mentioned that since their utility supplies electricity and natural gas it would be unlikely that they would purchase power generated by a competing fuel, such as propane.
- Economic modeling was done to determine the economic viability of augmenting a digester genset.
 - The results confirmed that using propane to stabilize the power output is not economically feasible.
 - In most of the cases where a second generator was added, there was not a good economic case for using propane for peaking power unless the peak power rate was above \$0.25/kWh.

- Using an additional generator to produce net metered power using excess biogas provides a significant benefit since the farm is able to use the generator year round, and even though the rate is much lower, it has a positive impact. The profitability of this additional power is much higher in states like New York where the utilities pay a higher rate for biogas derived power. In states where the net meter excess power purchase rate is lower, such as Pennsylvania and Maryland, the case is a tougher sell because the cost of the additional must be paid back mostly, or solely (in Maryland), from peak power sales.
- Most cases where propane was used to produce peaking power resulted in increased propane sales of 9,418 gallons per year. One case where propane is used in two generators simultaneously resulted in double this amount, 18,836 gallons per year.
- All of the farms that were interviewed said that they were interested in the concept and in participating in a follow-on demonstration project, if it was economically viable.
- The ultimate viability of this concept, and the ability to move on to the next stage, lies with the electric utilities and whether they are willing to allow peaking on propane, or any other fuel, from the digester farms and at what peak power rates.

Appendices

Appendix 1: Propane Availability Survey Results

Delaware

County	Propane Available?	Supplier (not all-inclusive list)
Kent	Yes	TriGas & Oil, Suburban Propane
New Castle	Yes	TriGas & Oil, Suburban Propane
Sussex	Yes	TriGas & Oil, Suburban Propane

Maryland

County	Propane Available?	Supplier (not all-inclusive list)
Allegany	Yes	Suburban Propane
Anne Arundel	Yes	Suburban Propane
Baltimore	Yes	United Propane, Suburban Propane
Calvert	Yes	United Propane, Suburban Propane
Caroline	Yes	TriGas & Oil, Suburban Propane
Carroll	Yes	Ferrellgas, United Propane, Suburban Propane
Cecil	Yes	AmeriGas, TriGas & Oil, Suburban Propane
Charles	Yes	United Propane, Suburban Propane
Dorchester	Yes	TriGas & Oil, Suburban Propane
Frederick	Yes	Ferrellgas, United Propane, AmeriGas, Suburban Propane
Garrett	Yes	Suburban Propane
Harford	Yes	AmeriGas, Suburban Propane
Howard	Yes	AmeriGas, Suburban Propane
Kent	Yes	TriGas, Suburban Propane
Montgomery	Yes	Suburban Propane
Prince George's	Yes	Suburban Propane
Queen Anne's	Yes	United Propane, TriGas & Oil, Suburban Propane
Somerset	Yes	Suburban Propane
St. Mary's	Yes	United Propane, TriGas & Oil, Suburban Propane
Talbot	Yes	United Propane, Suburban Propane
Washington	Yes	United Propane, AmeriGas, Suburban Propane
Wicomico	Yes	United Propane, Suburban Propane
Worcester	Yes	Suburban Propane

Pennsylvania

County	Propane Available?	Supplier (not all-inclusive list)
Adams	Yes	Suburban Propane
Bedford	Yes	Suburban Propane
Berks	Yes	Suburban Propane
Blair	Yes	Suburban Propane
Bradford	Yes	Suburban Propane
Cambria	Yes	Suburban Propane
Cameron	Yes	Suburban Propane
Centre	Yes	Suburban Propane
Chester	Yes	Suburban Propane
Clearfield	Yes	Suburban Propane
Clinton	Yes	Suburban Propane
Columbia	Yes	Suburban Propane
Cumberland	Yes	Suburban Propane
Dauphin	Yes	Suburban Propane
Elk	Yes	Valley National Gases
Franklin	Yes	Suburban Propane
Fulton	Yes	Suburban Propane
Huntingdon	Yes	Suburban Propane
Juniata	Yes	Suburban Propane
Lackawanna	Yes	Suburban Propane
Lancaster	Yes	Suburban Propane
Lebanon	Yes	Suburban Propane
Luzerne	Yes	Suburban Propane
Lycoming	Yes	Suburban Propane
Mifflin	Yes	Suburban Propane
Montour	Yes	Suburban Propane
Northumberland	Yes	Suburban Propane
Perry	Yes	Suburban Propane
Potter	Yes	Suburban Propane
Schuylkill	Yes	Suburban Propane
Snyder	Yes	Suburban Propane
Somerset	Yes	Suburban Propane
Sullivan	Yes	Suburban Propane
Susquehanna	Yes	Suburban Propane
Tioga	Yes	Suburban Propane
Union	Yes	Suburban Propane
Wayne	Yes	Suburban Propane
Wyoming	Yes	Suburban Propane
York	Yes	Suburban Propane

Virginia

County	Propane Available?	Supplier (not all-inclusive list)
Accomack	Yes	Bagwell Oil, Suburban Propane
Albemarle	Yes	Tiger Fuel, Suburban Propane
Alleghany	Yes	AmeriGas
Amelia	Yes	Southern States, Suburban Propane
Amherst	Yes	AmeriGas, Southern States, Suburban Propane
Appomattox	Yes	Tiger Fuel, Suburban Propane
Arlington	Yes	Southern States, Suburban Propane
Augusta	Yes	AmeriGas, Dixie Gas
Bath	Yes	Southern States
Botetourt	Yes	Southern States, Suburban Propane
Buckingham	Yes	AmeriGas, Suburban Propane
Caroline	Yes	Ray Adkins, Suburban Propane
Charles City	Yes	Revere Gas, Suburban Propane
Chesterfield	Yes	Ferrellgas, Spencer Bros. Propane, Suburban Propane
Clarke	Yes	Blossman, Suburban Propane
Craig	Yes	AmeriGas
Culpeper	Yes	AmeriGas, Quarles, Suburban Propane
Cumberland	Yes	Southern States, Suburban Propane
Dinwiddie	Yes	AmeriGas, Suburban Propane
Essex	Yes	Southern States
Fairfax	Yes	Fairfax Propane, Suburban Propane
Fauquier	Yes	AmeriGas, Quarles, Suburban Propane
Fluvanna	Yes	Quarles, Suburban Propane
Frederick	Yes	AmeriGas, Quarles
Gloucester	Yes	AmeriGas, Revere Gas, Suburban Propane
Goochland	Yes	Southern States, Suburban Propane
Greene	Yes	Quarles
Hanover	Yes	Virginia Propane, Suburban Propane
Henrico	Yes	Southern States, Suburban Propane
Highland	Yes	AmeriGas
Isle of Wight	Yes	Southern States, Suburban Propane
James City	Yes	Revere Gas, Suburban Propane
King and Queen	Yes	Adkins Propane, Suburban Propane
King George	Yes	Quarles
King William	Yes	First Virginia Propane, Suburban Propane
Lancaster	Yes	Noblett/Ware Propane
Louisa	Yes	Southern States, Suburban Propane
Madison	Yes	Quarles, Suburban Propane
Mathews	Yes	Revere Gas, Suburban Propane
Middlesex	Yes	Revere Gas, Suburban Propane
Nelson	Yes	Tiger Fuel, Suburban Propane
New Kent	Yes	Revere Gas, Suburban Propane

County	Propane Available?	Supplier (not all-inclusive list)
Northampton	Yes	Parker Oil, Suburban Propane
Northumberland	Yes	Revere Gas
Nottoway	Yes	Roy C Jenkins Inc, Suburban Propane
Orange	Yes	Southern States, Suburban Propane
Page	Yes	AmeriGas
Prince Edward	Yes	Suburban Propane
Prince George	Yes	Revere Gas, Suburban Propane
Prince William	Yes	Valley Energy, Suburban Propane
Rappahannock	Yes	Quarles, Suburban Propane
Richmond	Yes	Revere Gas
Rockbridge	Yes	Rockbridge Farmers CoOp, Suburban Propane
Rockingham	Yes	Home Pride Services
Shenandoah	Yes	AmeriGas, Holtzman
Spotsylvania	Yes	Ferrellgas, Quarles, Suburban Propane
Stafford	Yes	Quarles, Suburban Propane
Surry	Yes	Griffin Oil, Suburban Propane
Warren	Yes	Quarles, Suburban Propane
Westmoreland	Yes	Southern States
York	Yes	Revere, Suburban Propane

West Virginia

County	Propane Available?	Supplier (not all-inclusive list)
Berkley	Yes	Suburban Propane
Grant	Yes	Suburban Propane
Hampshire	Yes	AmeriGas, Suburban Propane
Hardy	No	
Jefferson	Yes	United Propane, AmeriGas
Mineral	Yes	Suburban Propane
Morgan	Yes	Suburban Propane
Pendleton	No	
Randolph	Yes	Suburban Propane

Appendix 2: Summary of State Interconnection and Net Metering Requirements

This information was located using the Database of State Incentives for Renewable & Efficiency webpage. The standards are presented in an easy to use table that links to the relevant state webpage.

The weblink is:

<http://www.dsireusa.org/summarytables/reg1.cfm?&CurrentPageID=7&EE=1&RE=1>. For an alternate method, and in case the page address is changed, the page is navigated to by this path Main Page → Summary Tables → Rules, Regulations, and Policies [Renewable Energy].

Interconnection Standards

Delaware

- Weblink: http://www2.state.de.us/publicadvocate/dpa/html/self_gen.asp
- <1MW includes non-renewable power generation.
- Systems from 25kW to 500kW, for all fuels, need a pre-interconnection study conducted and to have the necessary disconnect devices and equipment installed.
- Systems greater than 500kW need to be evaluated for direct transfer tripping relays, which requires a more detailed application.
- Exporting non-renewable derived power (i.e. propane) is allowed, but the mechanisms on how facilities/farms would be paid back were not clear.
- The project was discussed with Bob Howatt (Delaware Public Service Commission), who said that there are no similar applications using propane fuel for this type of application, but he did not see any reason that it would not be allowed.
- Contacts:
 - Bob Howatt, Delaware Public Service Commission, (302) 739-4247, robert.howatt@state.de.us.
 - Charlie Smisson, Department of Natural Resources and Environmental Control, Delaware Energy Office, (302) 739-1530, charlie.smisson@state.de.us.

Maryland

- Same as for Net Metering (see below).
- Contact: Chris Rice, Maryland Energy Administration, 410-260-7207, crice@energy.state.md.us.

Pennsylvania

- Section 5 of the Alternative Energy Portfolio Standards Act of 2004.
 - Includes “other distributed generation systems”, so it seems that propane generators would be allowed.
- The concept design would either be a Level 2 (inverter based <2MW) or Level 3 (other <2MW) because of power level and the need to export power to the grid.
- Contact: Greg Shawley, Pennsylvania Public Utility Commission, (717) 787-5369, gshawley@state.pa.us.
- The standards allow a single point of interconnection for a location with multiple generators.

- Spoke to Calvin Birge to discuss the project
 - There are no similar applications using propane fuel, but he did not see any reason that it would not be allowed.
 - Most utilities in Pennsylvania do not have to buy power. They only operate transmission and distribution infrastructure.
- Link to the Pennsylvania Public Utilities Commission webpage for the Alternative Energy Portfolio Standards Act of 2004 (http://www.puc.state.pa.us/electric/electric_alt_energy.aspx).
- Contacts:
 - Greg Shawley, Pennsylvania Public Utility Commission, (717) 787-5369, gshawley@state.pa.us.
 - Calvin Birge, Pennsylvania Public Utility Commission, (717) 783-1555, birge@state.pa.us.
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New York

- Includes “Other Distributed Generation Systems”, so sounds like it would allow for a propane generator, 2MW maximum per facility.
- Contacts:
 - (New York Department of Public Service) Michael Worden, michael_worden@dps.state.ny.us, 518-486-2498.
 - (New York Department of Public Service) Patrick Maher, Patrick_maher@dpw.state.ny.us, 518-486-2574.
 - (New York Department of Public Service) Charles Puglisi, charles_puglisi@dps.state.ny.us, 518-474-2530.
 - Utilities:
 - Central Hudson, Heather Adams, (845) 486-5552, hadams@cenhud.com.
 - Con Edison, Dan Sammon, 212-460-4010, sammond@coned.com.
 - Long Island Power Authority, Andy Garsils, 516-545-6122, agarsils@keyspanenergy.com.
 - NYSEG/RGE, John Zdimal, 607-762-8920, jjzdimal@nyseg.com.
 - National Grid, Denny Dvorak, 315-428-5259, Dennis.Dvorak@us.ngrid.com.
 - Orange and Rockland, Lenny Leon, 845-577-2599, leonl@oru.com.

Net Metering

Delaware

- Weblink to Delaware regulation that includes net metering <http://www.dsireusa.org/documents/Incentives/DE02Rb.htm>.
- For renewables ONLY (propane NOT included), 25kW maximum.
- Net excess generation.
 - Delmarva Power - credited to next month. If the payment is greater than \$100 the facility can request payment at the Standard Offer Service rate.

- Delaware Electric Co-Op – Excess generation credits can be rolled over/used for 12 months. After 12 months, can be sold to any utility, or will be forfeit.
- Contacts:
 - Bob Howatt, Delaware Public Service Commission, (302) 739-4247, robert.howatt@state.de.us.
 - Charlie Smisson, Department of Natural Resources and Environmental Control, Delaware Energy Office, (302) 739-1530, charlie.smisson@state.de.us.

Maryland

- Maryland Code for Net Metering for public utility companies (<http://www.dsireusa.org/documents/Incentives/MD06R.htm>).
- The net metering *incentive* applied to renewables (biomass, solar, wind) only → propane does not apply.
- 200kW generation limit; however, a petition can be submitted to extend to 500kW with Public Service Commission approval.
- Facilities have to be designed to primarily offset the customer's use. Excess power produced can be banked for 12 months and then are forfeit.
- Contact: Chris Rice, Maryland Energy Administration, (410) 260-7207, crice@energy.state.md.us.

Pennsylvania

- The requirements include “other distributed generation systems”, so it seems that propane generators would be allowed.
- Customers with systems that are part of microgrids or are available for emergency use are limited to 2 MW.
 - The customer is compensated monthly at utility's avoided-cost rate.
- The regulations mentioned in the Interconnection section also apply here.
- Contact: Calvin Birge, Pennsylvania Public Utility Commission, (717) 783-1555, birge@state.pa.us.

New York

- Restricted to renewables (photovoltaic, wind, biomass, etc.).
 - There was no mention of how power generated from other fuels is dealt with.
- Farm based digesters up to 400kW are allowed.
- Energy is credited at the regular retail rate (except wind which is paid only at the avoided cost rate).
- Contact: (New York Department of Public Service) Patrick Maher, Patrick_maher@dpw.state.ny.us, 518-486-2574.
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