April 2008 E.B. 2008-04

Economic Analysis of Anaerobic Digestion Systems and the Financial Incentives provided by the New York State Renewable Portfolio Standard (RPS) Customer-Sited Tier (CST) Anaerobic Digester Gas (ADG)-to-Electricity Program

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ABSTRACT

This paper conducts a financial analysis of anaerobic digestion systems on dairy farms and describes a financial model developed for this purpose. The model is flexible and can be utilized with farm-specific data to assist in the evaluation of an anaerobic digestion system. The model is illustrated with two sources of data. The "base" case is the more flexible model and the parameters to utilize the model were developed from a wide range of resources. The second model is meant to be used in conjunction with FarmWare 3.1 which was developed and distributed by the United States Environmental Protection Agency's AgStar Program.

The analysis also explicitly incorporates the financial incentives offered under the New York State Energy Research and Development Authority's Customer-Sited Tier Anaerobic Digester Gas-to-Electricity Program. The analysis indicates that a variety of parameters are very important in determining the economic viability of anaerobic digester projects. These key variables include the biogas energy yield, current on-farm energy use, prices paid for electricity, the price received for excess electricity generation, the ability to co-digest other waste streams, capital, and operating costs. Based upon reasonable estimates of the costs of such a project for a 1,000 cow dairy operation, it would appear that anaerobic digestion is of marginal profitability. However, there are a variety of reasonable scenarios where the profitability of the system is very attractive.

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INTRODUCTION

Anaerobic digestion systems provide an opportunity for livestock producers to produce renewable energy from livestock wastes. These systems are typically quite capital intensive and require a thorough economic analysis to assess economic feasibility. Economic fundamentals such as rising energy prices continue to improve the economic potential of these systems. In addition, various incentive programs have emerged to further encourage the development of anaerobic digestion systems. For instance, the New York State Energy Research and Development Authority (NYSERDA) is offering up to $11 million (maximum of $1 million per Anaerobic Digester Gas to electricity (ADG) system) in financial incentives, under the Customer-Sited Tier (CST) Anaerobic Digester Gas-to-Electricity Program, to support the installation and operation of ADG-to-electricity systems in New York state.

The NYSERDA program provides two types of financial incentives – capacity and performance incentives. The former are capacity buy-down payments that offset some of the costs for the purchase and installation of ADG-fueled electric power generation equipment at customers' (host) sites, while performance-based incentives encourage on-site electricity production. For customers such as livestock farms, the program would assist in the adoption of anaerobic digester technologies that can produce energy for on-site use and possible sale as well as address waste management problems.[2]

This report summarizes an economic assessment of anaerobic digestion projects and the incentives. First, a brief summary of the ADG-to-electricity program is presented. Next, the incentives offered under the program and their financial implications are outlined. A financial model of the incentives is then built to assess the financial implications. The paper uses a spreadsheet-based assessment tool that can be used to analyze an AD system. The spreadsheet is available from the authors and at: http://www.agfinance.aem.cornell.edu/. Finally, the findings of the analysis and conclusions drawn regarding the economic value of the program are presented.

ANAEROBIC DIGESTER GAS-TO-ELECTRICITY PROCESS

A wide variety of resources are available to describe the process of turning waste material into energy. The Cornell manure management program website, http://www.manuremanagement.cornell.edu/, provides resources related to producing energy from the anaerobic digestion of agricultural waste. As such, this report does not provide detailed information on the technical aspects of anaerobic digestion systems. Likewise, while anaerobic digestion systems are capable of producing energy for a variety of end uses, this report focuses only on systems that convert biogas to electricity.

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[2] NYSERDA offers financial incentives for the adoption of solar photovoltaics, small wind turbine and fuel cell technologies for energy generation under other customer-sited tier (CST) programs.

Anaerobic digestion of solid wastes to produce biogas is one of many possible technologies available for waste management on animal farms. Anaerobic digestion (AD) involves the breakdown and conversion of organic materials to biogas by methanogenic bacteria. The primary constituents of biogas are methane (CH_4) and carbon dioxide (CO_2). While the methane content of biogas is variable, biogas produced by livestock waste is typically between 55 and 65 percent methane. (Martin; Scott and Ma; U.S. EPA; Wright; Scott, et. al.,). The vast majority of the remaining gas is carbon dioxide, but biogas also contains a variety of other compounds, such as hydrogen sulfide (H_2S) which is a corrosive compound. The presence of compounds like hydrogen sulfide and other impurities can complicate the use of biogas. For instance, hydrogen sulfide can significantly increase maintenance costs when used in combustion engines.

When biogas is captured and combusted in an electrical generation system the process creates renewable energy. In addition to reducing or eliminating the farm's purchases of electricity, this renewable energy can be substituted for fossil fuel based energy, reducing the green house gas emissions associated with energy consumption. Likewise, because methane is a potent greenhouse gas, its combustion results in a reduction in the livestock operation's net contribution to green house gas emissions. Currently there are some voluntary programs available to monetize these reductions in green house gas emissions.

The ADG-to-electricity system consists of a digester system that converts solid waste into reduced solid and gas forms. The non-gas product of the AD process is rich in nutrients and can be used as field fertilizers much like undigested manure. Biogas produced from the digester is utilized in an electrical generation system. This generator is then connected to the farm electrical system making the energy available to power on-farm equipment with excess generation metered and sold on the electrical grid.

The NYSERDA incentives analyzed in this paper are for farms that utilize AD created biogas in on-farm ADG-to-electricity systems.

THE ADG-TO-ELECTRICITY PROGRAM INCENTIVES

The NYSERDA program is offering up to $1 million per ADG-to-electricity system to support the purchase, installation and operation of customer-sited ADG-fueled electrical power generators. These incentives are available in the form of capacity incentives and performance incentives.

Capacity-based incentives offer $500 per kilowatt to cover the total purchase and installation costs of new ADG-fueled power generating equipment.[3] New equipment refers only to ADG-fueled electric generating equipment purchased and installed at host site on or after February 12, 2007. The incentive is only available on equipment that represents incremental increase in ADG-fueled electricity generated at the host site as of February 11, 2007. The largest capacity incentive that any farm can receive is the

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[3] Costs covered included controls, meters, biogas clean-up equipment, emissions control equipment, interconnection equipment and costs associated with engineering services.

maximum of $350,000 or fifty percent of the total costs incurred in purchase, installation and engineering services costs. Incentives received for any ADG-to-electricity system under this category cannot be combined with previous funding for the same ADG-fueled equipment.

Performance-based financial incentives provide payments of $0.10 per kilowatt-hour for electricity generated by new equipment. This funding is available for up to three years. For eligible existing equipment, performance incentives give lower payments of $0.02 per kilowatt-hour. Eligible existing equipment refers to ADG-fueled equipment that would have been purchased for, or installed after January 01, 2003, and before February 12, 2007, and or substantially upgraded since January 01, 2003.

The total financial incentives that a farm is eligible to receive are the eligibility capacity limit or as large as necessary to meet approximate Peak Connected Load (PCL) at the site's meter. The eligibility capacity limit is based on the net energy metering law that currently caps the size of farm waste generating equipment at 400 kilowatts. There is however some flexibility to the restriction on total incentives that an establishment can receive, as incentives exceeding the stated maximum can be approved for projects that are deemed to be of sufficient public benefit.

CALCULATING THE FINANCIAL INCENTIVES

The Incentive Estimation Tool developed by NYSERDA is the basis for requests for funding under the ADG-to-electricity Program. This tool helps farms applying for financial incentives to calculate the maximum total incentive that they may be eligible to receive. The tool allows applicants to estimate incentives for different purchase, installation and operation scenarios. For example, a farm business may:

1. Have no eligible existing equipment, install new equipment and request for maximum eligible capacity and performance-based incentives.
2. Own eligible existing equipment and apply only for maintenance incentives for this equipment.
3. Apply for maintenance incentives for eligible existing equipment; and capacity and performance incentives for the installation of new equipment.
4. Replace existing equipment with new and request funding for electricity generation over and above former capacity.

A complete description of the financial incentives can be found (under PON 1146) at http://www.nyserda.org/funding/funding.asp?i=2

DATA AND ANALYSIS

The aim of the economic assessment is to determine if incorporating an ADG-to-electricity system in a dairy farm operation is of economic value. The implications of the financial incentives on a hypothetical project's value are also assessed.

The economic assessment is carried out using a discounted cash flow analysis and pro-forma financial statements generated in Microsoft Excel. While the model is flexible and can accommodate a wide range of farm sizes, the results presented in this paper consider the case of a 1,000 cow dairy farm. There are a variety of assumptions that must be made to conduct the assessment. These assumptions include characteristics of the dairy farm, the AD system, and financial assumptions. Based upon these data the appropriate calculations are made to produce an estimate of the economic potential of the system.

The U.S. EPA AgStar program has produced an AD system evaluation tool called FarmWare 3.1. The tool and documentation are available for free download at: http://www.epa.gov/agstar/resources/handbook.html. The FarmWare 3.1 tool requires that the user input information regarding the dairy farm and biogas system. It then estimates capital costs, electricity generation potential, and profitability, among other things. One example reported in this paper utilizes the outputs of the FarmWare 3.1 assessment as part of the required inputs for a complete economic assessment.

The second example requires that the user input a similar, but slightly different set of inputs to conduct the analysis. The second example is more flexible in that the user has the option to alter a wider variety of parameters that impact the economic viability of the project. The FarmWare 3.1 screening can be used if the user has little or no information available on the costs and sizing of the AD system. Once the user has obtained a more complete set of cost and production estimates for the AD system, the second tool can be utilized. The report will describe and compare the results produced with these two models.

The projects examined in this report are for illustration purposes only. The capital budgets for the "Base" example were taken from estimates provided on the Cornell Manure Management website: http://www.manuremanagement.cornell.edu/HTMLs/EconomicModel.htm. Estimates of the energy production potential were derived from assumptions regarding manure production and conversion efficiency of the digester. The capital costs and revenues from the "FarmWare" example were obtained from FarmWare 3.1. In both cases, the estimates are for a 1,000 cow dairy operation. The "base" example requires that the user input more information to the spreadsheet. The basic information that is required for the analysis is shown in Table 1. The information in Table 1 is consistent across both examples.

Table 1. Basic Input Parameters for the AD Financial Analysis in the base and FarmWare Spreadsheets.

Parameter	"Base Example"	"FarmWare Example"
Lactating Cows	800	800
Dry Cows	200	200
Total Cows	1,000	1,000
Participation in NYSERDA Capacity Incentive	Yes	Yes
Participate in NYSERDA Performance Incentive	Yes	Yes
Other Grant Dollars	$0	$0

The inputs require that the user specify the number of lactating and dry animals. This is important because manure production differs considerably for these types of animals. Additionally, the inputs allow the user to indicate whether they will participate in the NYSERDA capacity and performance incentive programs. The amount of the grant for which the system would qualify is calculated from subsequent inputs in the spreadsheet. The final input item allows the user to input the gross value of any additional grants that they receive for the project.

Capital Budgets

The capital budgets for each example are input next (Table 2). The capital budgets specify the dollar amount for a variety of capital asset categories. The user must also enter the percent of the asset that is associated with generation equipment. This information is necessary for calculation of the NYSERDA capacity incentive. The user must also enter the number of years over which the asset will be depreciated. Two choices are available for this option, seven years or 20 years. This information is used to build the depreciation schedule for the financial statements. The depreciation is based upon the modified accelerated cost recovery system (MACRS) depreciation schedule. If one wants to enter different depreciation schedules or asset lives, modification of the spreadsheet is required.

The descriptive titles for the assets can be changed to suit the needs of the user, but adding additional rows will require additional changes to the spreadsheet. The last category to be entered is the working capital required for the project. Working capital represents the amount of funds that must be held to make necessary incremental payments for labor, supplies, etc. The actual inventory values will also be added in a later section.

Table 2. Capital Budget for Base Example.

Item	Amount	Percent for Generator (%)	Depreciation (Yrs)
Land	0	0	
Building	$ 100,000	30	20
Site Work	$ 45,000	33	20
Power Wiring	$ 135,000	94	20
Manure Piping	$ 15,000	0	20
Generator	$ 150,000	100	7
Boiler	$ 25,000	10	7
Digester Tank	$ 200,000	0	20
Pumps	$ 20,000	0	7
Controls	$ 14,250	95	7
Project Development	$ 42,500	Calculated	Calculated
Engineering	$ 67,500	Calculated	Calculated
Construction Management	$ 108,000	Calculated	Calculated
Consulting	$ 18,000	Calculated	Calculated
Total Capital Costs	$ 940,250	Calculated	Calculated
Working Capital	$ 30,000		

Table 3 shows the capital budget items for FarmWare 3.1 example. The capital asset categories in this section are designed to correspond to the categories that are created by FarmWare 3.1. It should be noted that these capital budget estimates are created by FarmWare 3.1 and details of the assumptions underlying the creation of these values can be obtained in the FarmWare 3.1 documentation. The spreadsheet allows the user to enter additional categories generated by their specific application of FarmWare in the row entitled *others FarmWare*. The user can also enter their own additional capital budget items in the row entitled *others user*. Again, the final input is for working capital expenses which are not estimated by FarmWare 3.1. As in the “base” example the user must assign the percentage of the capital expenditures which are associated with generation equipment so that the spreadsheet can calculate the NYSERDA capacity incentives.

Table 3. Capital Budget for FarmWare 3.1 Example.

Item	Amount	Percent for Generator (%)	Depreciation (Yrs)
Digester	$ 707,970	0%	20
Engineering	$ 23,722	30%	7
Engine generator	$ 47,636	100%	7
Basin	$ 9,077	0%	20
Secondary storage	0	0%	0
Others FARMWARE	0	0%	0
Others USER	0	0%	0
Total Capital Cost	$ 788,405	Calculated	
Working Capital	$ 30,000		

The days of inventory for supplies and accounts payable and receivable comprise the next set of inputs required in both the base and the FarmWare examples. These inputs are shown in Table 4. The days in inventory of these items are used for creation of the inventory numbers on the pro-forma balance sheets.

Table 4. Days in Inventory for Various Balance Sheet Items for Base and FarmWare Examples.

Item	Days in Inventory
Fuels, etc.	20
Accounts Receivable	20
Accounts Payable	25

Energy and Biogas Production Assumptions

Next, the information required to calculate the energy generation potential of the system is entered. The information requirements differ for the base and FarmWare examples. The inputs required for the base case are shown in Table 5.

Table 5. Energy and Biogas Production Assumptions, Base Case.

Assumption	Value
Manure:	
Solid conversion to biogas (%)	30%
Cubic Feet of biogas produced per pound of volatile solid converted	16
BTU's per cubic foot of biogas	625
Other Waste Streams:	
Tipping fees per ton of waste (net of disposal costs)	0
Tons of other waste per day	0
Volatile solid content (%)	40%
Solid conversion to biogas (%)	30%
Cubic feet of biogas produced per pound of volatile solid converted	16
BTU's per cubic foot of biogas	625
Electricity Conversion and Use Assumptions:	
Thermal conversion efficiency of electricity generation equipment (%)	25%
Daily on-line percent for electricity generation equipment (%)	90%
Pre-system on-farm power requirement (kWh/year)	850,000
Power use of AD system (kWh/year)	54,750
Purchase price of electricity from grid ($'s/kWh)	$0.12
Sale price to grid ($'s/kWh)	$0.070
Carbon credit price ($'s/ MT CO2)	$2.00
Type of existing manure storage	Anaerobic lagoon or liquid/slurry

The base spreadsheet allows the user to consider the energy production potential for manure and other waste streams. The key elements in calculating the energy production from manure are the volatile solid conversion rate, the cubic feet of biogas produced per pound of volatile solids, and the BTU content of the biogas. The values in Table 5 are based upon estimates derived from the anaerobic digestion literature (Krich, et.al., Martin and Roos). The volatile solid content of the manure is estimated based upon the number of lactating and dry dairy cows and the estimated manure production of these cows (ASAE). Based upon the values in this table and the embedded manure production assumptions, a lactating dairy cow would produce 81 cubic feet of biogas per day. This is equivalent to approximately 51,000 BTU's per lactating cow per day. At a price of $6/MMBTU, manure from lactating dairy cows would have an energy value of approximately $4 per ton. These values and calculations can be found in the gas production sheet of the workbook.

The spreadsheet also allows the user to estimate the value of including additional waste streams in the digester. The sheet requires that the user input the amount of tipping fees per ton net of disposal costs as well as the amount of additional wastes that would be added to the digester on a ton per day basis. The remaining calculations for energy production are similar to the case for manure, but note that the parameters for volatile solid content and conversion may differ for alternative waste streams. The analysis in this report does not include additional waste streams.

The user then enters the thermal conversion efficiency of the engine generator equipment. This information is used to convert the BTU's of biogas into kWh's. The standard conversion factor of 1 kWh per 3,412 BTU's is combined with the efficiency factor to estimate the total number of kWh's that the system is capable of generating. The daily on-line percentage of the generation system is used to determine the amount of electricity that is generated by the system, assuming that when the generator is not running, biogas is sent to a flare.

The amount of energy that the farm uses before digestion is a critical piece of information. This determines the amount of energy purchases that can be off-set by the AD system. This information is entered as the total kWh used per year. Because the digestion system will also consume electricity, it is important to consider the amount of energy that the system will consume. This value is entered as the total kWh used by the digestion system per year. This value is not credited toward system savings or sales.

The purchase price for electricity for the farm is entered in dollars per kWh. The value should reflect the price that the farm pays for electricity from the grid prior to the AD system installation. In some cases it may take some additional calculations to arrive at this price. The value should not include any "standby" or "demand" charges that will still be charged to the farm after the digester is operational. The price that is received for electrical sales to the grid in $'s per kWh is the next input. Again, additional calculations may be necessary to obtain the net value that the farm receives for sale to the electrical grid. The utility should be able to provide the farm with an accurate measure of all of these items.

The final input required to estimate the revenues of the AD system is the amount of carbon credits generated by the system and the price that the farm would receive for any carbon credit sales. The value is entered as $'s per metric ton of CO_2 equivalent. The spreadsheet calculates the amount of credits available to the farm based upon the calculations required for certification for the Chicago Climate Exchange (CCX): www.chicagoclimateexchange.com/docs/offsets/Agriculture_Methane_Protocol.pdf. Because the actual offset granted to the project will be the lower of the measured amount of methane destroyed or these "ex ante" calculations, the spreadsheet makes the explicit assumption that the measured methane reduction will be greater than the amount calculated by the ex ante procedure of the CCX.

In order to calculate the amount of carbon credits available it is necessary to identify whether the farm currently uses an anaerobic lagoon or a liquid/slurry manure storage system. Farms utilizing an anaerobic lagoon will be eligible for a greater amount of CO_2 equivalent off-sets. Additionally, the farm must specify the number of heifers and cows on the site. The calculations in the spreadsheet only consider the number of mature dairy animals on the site. Farms may also be eligible for credits associated with off-setting electricity from the traditional grid. This tool does not consider these off-sets in its calculations.

The energy production assumptions required for the FarmWare example are shown in Table 6. Because FarmWare estimates biogas and electricity generation potential directly in its assessment, the inputs are simplified from the base case. Here, the user enters the total cubic feet of biogas and methane produced per year as well as the total BTU's produced per year. These inputs come directly from the FarmWare assessment.

Table 6. Energy and Biogas Production Assumptions, FarmWare Case.

Assumption	Value
Biogas Production:	
Total biogas (CF/year)	29,116,117
Total methane (CF/year)	16,741,765
BTU's per year	15,452,625,000
Manure Production:	
Collectable Manure (lbs/day)	204,744
Collectable Total Solids (lbs/day)	13,746
Collectable Total Volatile Solids (lbs/day)	11,215
Electricity Generation:	
Total electricity generation (kWh)	1,358,276
Generator size (kW)	190
Thermal conversion efficiency (%)	30%
Pre-system on-farm power requirement (kWh/year)	850,000
Power use of ADG system (kWh/year)	54,750
Purchase price of electricity from grid ($'s/kWh)	$ 0.12
Sale price to grid ($'s/kWh)	$ 0.070
Carbon credit price ($'s/ MT CO2)	$ 2.00
Type of existing manure storage	Anaerobic lagoon or liquid/slurry

The spreadsheet also asks the user to input the manure production characteristics from the FarmWare assessment. These values are also calculated by FarmWare. The next section requires the user to input the electricity generation assumptions from the FarmWare assessment. These values are generated by FarmWare with the exception of the information regarding the on-farm power use, ADG power use, electricity prices, and carbon credit information. These values should be derived in the same manner as in the base example described above.

Operating Costs

The operating costs for the system are input in the next section. The base spreadsheet allows the user to consider a variety of operating costs. The FarmWare assessment estimates operating costs for the system directly, so the FarmWare example asks the user to input these costs in one cell of the spreadsheet. It appears that FarmWare estimates these costs on the basis of 5 percent of total capital costs. The user should note that this may or may not be a good estimate of the actual operating costs that would be expected. In the base case, the user has the option of entering values for a variety of operating costs or estimating them using a percent of capital costs. Table 7 shows the categories of operating expenses that can be entered.

Table 7. Operating Expense Estimates for the AD System, Base Case.

Operating Expense	Value
Operating, Repairs, and Maintenance % of Capital	5.0%
Operating, Repairs, and Maintenance	Calculated if value above is non-zero
Property Taxes	0
Insurance	0
Office	0
Oil and Fuel	0
Accounting and Legal	0
Labor	0
Total Expenses	Calculated
Operating Cost per kWh ($'s/kWh)	Calculated

In the example in Table 7, the operating costs are calculated as a percent of total capital expenditures. As stated before, this is likely a poor estimate of the actual operating expenses of the system because operating expenses may not correspond to capital expenses. Additionally, it is very important to include maintenance expenses that maintain the equipment in proper operating condition. If new generation equipment must be purchased, it is critical that these expenditures are either explicitly estimated at specific points in time or that the annual charges included in the operating and maintenance costs are sufficient to replace equipment when necessary.

The user is encouraged to enter their own estimates of the operating expenses in the categories. The categories are designed to capture the major elements that might be associated with operating the digester. The operating costs per kWh are also calculated at the bottom of the table. This is based upon the amount of electricity that is generated. The user should note that this cost does not reflect the substantial capital costs associated with the system.

Financial Assumptions

A variety of financial information is required to finalize the assessment. This information is similar across the base and FarmWare examples. Table 8 shows the required financial information. This information is used to calculate the interest and principle payments for the system. It is also used in the discounted cash flow analysis of the project.

Table 8. Financial Assumptions for the Base and FarmWare Assessments.

Variable	Value
Percent Financing on Personal Property	65%
Term on Personal Property (years)	7
Rate on Personal Property (%)	8%
Percent Financing on Real Property	70%
Land percent financed	80%
Term on Long-Tem Financing	20
Rate on L.T. financing	8%
Discount Rate	10%
Terminal Value Multiple	10
Terminal Value Implied by Discount Rate	Calculated

The first variable is the percent financing of personal property (7 year life assumed). For example, if 65% of the cost of the property will be financed with debt, the user would enter 65%. The term of the loan is then entered as is the interest rate. This information is used by the program to calculate the debt service for the project. Similarly, the user can enter different values for land and long term property. Again, this information is used to calculate the debt service for the project.

The discount rate is also required. This value will be used to discount the future cash flows generated by the project. The discount rate should reflect the opportunity cost of capital for the firm conducting the analysis. The establishment of a proper discount rate is beyond the scope of this report. In most cases users should enter their weighted average cost of capital. The weighted average cost of capital is simply the required return on debt and equity capital weighted by the proportions of each that are used to finance operations. For instance, if the operation typically uses 60 percent debt with an average interest rate of 8 percent and the required rate of return on equity is 12 percent the weighted average cost of capital is 9.6% (0.60*.08 + 0.40*0.12). If the project is financed differently than the rest of the operation, some accommodation should be made for that in establishing the discount rate. In all cases, the discount rate should be greater than the interest rate paid on debt.

The basic discounted cash flow analysis uses a project time horizon of ten years. The terminal value multiple can be used to place an ending value on the project. The terminal value multiple is based upon the concept of valuing the ongoing business as a multiple of the cash flow that it generates into perpetuity[4]. The perpetuity value is then discounted by the appropriate number of periods to bring to net present value. For example, if a terminal value multiple of ten is employed at year ten, the free cash flow at the end of the tenth period is multiplied by ten to determine the terminal value. This value is then discounted by ten periods to bring it to present value. The selection of a terminal value multiple can have a large impact on the net present value of the project. The most conservative assumption is to use a terminal value multiple of 0. The terminal value implied by the discount rate is calculated by dividing 1 by the discount rate. For example, if the discount rate is 10 percent the implied terminal value multiple is 10. Higher discount rates result in lower terminal value multiples.

Financial Statements and Assessment

The spreadsheets use the above inputs to generate an income statement, balance sheet, cash flow statement, net present value, and internal rate of return. The discounted cash flow analysis is conducted by calculating cash flow generated by the project as the earnings before interest, taxes, depreciation, and amortization. The initial outlays of the project are the total capital costs associated with the project. The cash flows are discounted by the discount rate associated with the project.

The discounted cash flow analysis makes several important assumptions. First, all of the project start-up costs are assumed to be incurred at the beginning of the project. The total capital costs of the project include all capital items as well as working capital. The capacity incentive grant income is treated as a negative expense and is realized in the first year of operation. The performance incentive income is realized at the end of each of the first three years of the project. In all cases, the analysis assumes that the user qualifies for the incentive on new equipment. If one were to examine the incentives available for existing equipment modification of the analysis would be required.

The analysis does not consider the impact of inflation. This means that the cash flows to the project should be viewed as real cash flows and the discount rate used should be a real discount rate. Revenues from the operation of the digester are assumed to accrue in the form of both avoided electrical expenditures as well as sales of excess electrical production to the grid.

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[4] The value of perpetuity is obtained by dividing the annual cash flow generated by the project by the discount rate. This is the value of a constant annual cash flow received in perpetuity.

Summary of the Two Examples

The previous section described the basic inputs for the two examples under consideration. The parameter estimates for these AD systems on a 1,000 cow dairy operation were taken from the Cornell Manure Management website (base case) and FarmWare 3.1. The FarmWare analysis considered the case of a 1,000 cow dairy and complete mix digester in Cayuga County, New York. The capital costs and grant income for these operations are shown in Table 9.

Table 9. Capital Costs and Grant Income for the Base and FarmWare Examples.

Parameter	Base Case	FarmWare Case
Total Capital Costs	$ 970,250	$ 818,405
Total Costs Associated with Generation Equipment	$ 450,925	$ 54,752
Capacity of Generation Equipment (kW)	141	190
NYSERDA Capacity Incentive	$ 70,706	$ 27,376
Annual NYSERDA Performance Incentive (3 years)	$ 99,102	$ 133,152

One can observe that the assumptions for the two systems differ considerably. The capital costs for the base case are substantially greater than the FarmWare estimate. More striking is the difference in the assumed cost of the generation equipment. The base case makes assumptions that allocate some of the building and engineering costs to the generation system, while the FarmWare estimate likely does not. Accordingly, the capacity incentive is greater for the base case than for the FarmWare case. The capacity incentive was calculated according to equation (1).

(1) Capacity Incentive = *Min* ($350,000, $500*capacity, 0.50*GenCosts)

Here, *Min* is the minimum of the arguments in parentheses, capacity is the kilowatt capacity of the installed generator, and GenCosts are the total costs associated with the generation equipment (this includes controls, meters, biogas clean-up equipment, emissions control equipment, interconnection equipment, and costs associated with engineering services). In the base case the capacity incentive is determined by $500 times the capacity of the generator, while in the FarmWare case, the incentive is limited to 50% of the generation equipment costs.

The performance incentives also differ for the two examples. The performance incentives were calculated following the example in the NYSERDA incentive estimation tool. Specifically, the annual incentive was estimated using (2).

(2) *Performance = Capacity(kW) * 8,670 hours/year * 80% operating * $0.10/kWh*

Where *performance* is the annual performance incentive, *capacity* is the capacity of the generation equipment in kW, 8,760 is the number of hours in a year, 80% is the assumed capacity factor, and the performance incentive is paid at a rate of $0.10 per kWh. The analysis makes several important assumptions. First, the generator that is estimated by the spreadsheet is assumed to operate at the NYSERDA rated capacity. Second, the analysis is only valid for an operation that is installing new equipment, there is no eligible existing equipment on the site, and the site has not received previous NYSERDA funding for the equipment. If these assumptions are not valid, the incentives calculated by the spreadsheet are incorrect. For operations considering installation, all calculations should be verified with NYSERDA.

In the two cases considered, the base case receives a smaller incentive payment because the estimated electrical production and generator capacity is smaller for the base case (141 kW) than that estimated by FarmWare (190 kW). The FarmWare analysis predicts that the system should produce approximately 1.36 million kWh's per year while the base case shows 1.1 million kWh's per year.

This result shows some of the difficulty in estimating the economic returns to the project. While FarmWare installs a larger generator, the capacity incentive was actually smaller than the base case because the proportion of expenses attributed to the generation equipment was smaller in the FarmWare estimate. On the other hand, the FarmWare case received a larger performance incentive because it predicts a greater electrical output. The key point is that it is very important to carefully estimate the energy production potential and costs of the equipment before proceeding with the decision to install a system.

In order to compare the two examples, the first year income statement was developed for the two examples (Table 10). The income statement highlights some of the key differences in the two approaches. The gross revenue estimated by FarmWare is 23 percent greater than in the base case. This is generally the result of the greater electrical output estimated by FarmWare. Additionally, FarmWare estimated lower capital requirements than the base case. Because both examples estimated operating and maintenance costs at 5 percent of capital expenditures, the operating costs for the FarmWare example were 16 percent lower than for the base case. This also had the impact of substantially lowering the depreciation and interest cost estimates for FarmWare as opposed to the base case. As discussed in the previous section the estimates of grant income also differed dramatically across the two examples. In terms of discounted cash flow analysis, the measure of most importance is earnings before interest, taxes, depreciation, and amortization (EBITDA) which was 6 percent greater for the FarmWare estimate. This is quite important because not only were the capital costs lower for FarmWare (Table 9), the cash flow estimate was actually larger. As a result, the FarmWare estimate is more likely to produce a positive net present value.

Table 10. Income Statements for the Two AD Examples.

Revenues	Base Case	FarmWare	% Difference
Energy sales to dairy	$102,000	$102,000	0%
Energy Sales to Grid	$14,710	$31,747	116%
Performance Incentive	$99,102	$133,152	34%
Tipping Fees Net of Disposal Costs	$0	$0	N/A
Carbon Credits	$8,340	$8,340	0%
Gross Revenues	$224,152	$275,238	23%
<u>Operating Expenses</u>			
Grant	-$70,706	-$27,376	-61%
O&M	$47,013	$39,420	-16%
property taxes	$0	$0	
Insurance	$0	$0	
Office	$0	$0	
Oil and Fuel	$0	$0	
Accounting and Legal	$0	$0	
Labor	$0	$0	
Depreciation	$69,244	$37,086	-46%
Interest	$51,364	$43,865	-15%
Total Expenses	$96,914	$92,995	-4%
Net Income	$127,238	$182,243	43%
EBITDA	$247,846	$263,195	6%

The results of the discounted cash flow analysis are shown in Table 11. Here, one can see that the FarmWare estimate produces a greater net present value (NPV) and internal rate of return (IRR). The net present value was calculated by summing the discounted value of the EBITDA generated over 10 years of the project. For this analysis the discount rate was arbitrarily set to 10 percent. The analysis also assumed a terminal value EBITDA multiple of 10. This assumption is consistent with the 10 percent discount rate and assumes that the operation continues indefinitely into the future from year 10. As was pointed out in the discussion of operating and maintenance costs, it is critical that the operating costs are sufficient to replace the generation and other capital equipment when needed. This is necessary because depreciation expenses are added back to net income to arrive at EBITDA which is then discounted. Sensitivity to this assumption is addressed in a later section.

Table 11. Net Cash Flows and Net Present Value for the Two Examples.

Year	Base	FarmWare
0	-$ 970,250	-$ 818,405
1	$ 247,846	$ 263,195
2	$ 177,139	$ 235,818
3	$ 177,139	$ 235,818
4	$ 78,037	$ 102,666
5	$ 78,037	$ 102,666
6	$ 78,037	$ 102,666
7	$ 78,037	$ 102,666
8	$ 78,037	$ 102,666
9	$ 78,037	$ 102,666
10	$ 78,037	$ 102,666
Terminal Value	$ 780,373	$ 1,026,663
Net Present Value	$ 90,767	$ 524,693
IRR	12.0%	22.2%
NPV with Zero Terminal Value	-$ 180,014	$ 168,452
IRR No Terminal Value	4.2%	16.0%
Payback Period	8	4

The results in Table 11 indicate that, under the assumptions in the base analysis, the project is unlikely to achieve a positive net present value unless one places a large terminal value on the project. As evidenced by the low IRR with a zero terminal value, the project barely generates enough cash to simply recover the upfront cash costs. Specifically, payback of the original capital occurs in year 8 under the base case. A project with this cash flow stream would likely not be an attractive investment. On the other hand the cash flows from the FarmWare example show that even with a zero terminal value at year 10 the project would generate a positive net present value under a 10 percent discount rate. Payback in the FarmWare example occurs in year 4.

The above results indicate that, for the assumptions considered, the AD system would have marginal to poor economic profitability. As mentioned earlier, the specific inputs used in the AD analysis are highly specific to the situation at hand. In particular, one would expect that capital costs and operating experience could vary tremendously across AD installations. This leads one to consider how altering various factors would improve the projected profitability of AD projects. The next section of the report considers how a variety of factors influence profitability of these projects.

IMPROVING AD PROFITABILITY

Changes in a number of the underlying factors could lead to improvements of the NPV. In particular, lower start-up costs and/or higher revenues would increase NPV. In this section some of these factors are assessed. The analysis in this section only considers how changes in the assumptions in the base model would influence the NPV of the proposed project. All of the analyses presented assume a zero terminal value multiple. In other words, the terminal value is set to $0.

From the above analysis it is clear that the NYSERDA incentives greatly enhance the profitability of AD. In the cases above, the performance incentives were particularly valuable. The performance incentives added $99,102 per year for three years to the base example. The present value of these incentives with a 10 percent discount rate is approximately $246,000. Without these incentives the NPV of the base case would be reduced by this amount making it even less desirable. These incentives illustrate the important impact that revenue enhancement can have on the project.

Aside from the NYSERDA performance incentives revenue could be enhanced in a variety of ways including increasing biogas production, increasing the price of electricity sold to the grid, increasing the price of electricity purchased from the grid, and including additional waste streams in the digestion unit. Additionally, the assumption about the amount of energy consumed on the farm is a key assumption. This factor has the impact of determining the price for a large proportion of the energy produced by the unit. In effect, energy that off-sets farm purchases is priced at the retail electrical prices. It is quite possible that the assumption about energy demand of the farm in the base model is low. Table 12 shows how changing the assumption about on-farm electrical consumption alters the NPV of the project.

Table 12. The Impact of Altering Existing On-Farm Energy Use on the Profitability of an AD System.[a]

Total Energy Use (kWh/yr)	Energy Use per Cow (kWh/yr)	Average Price Received ($'s/kWh)	Annual Energy Savings and Sales	NPV	% Change in NPV
700,000	700	0.0980	$109,210	-$226,098	0
850,000	850	0.1047	$116,710	-$180,014	20%
1,000,000	1000	0.1114	$124,210	-$133,930	41%
1,150,000	1150	0.1200	$133,788	-$ 75,081	67%

[a] The analysis assumes the retail price of electricity is $0.12 per kWh and the wholesale sales price is $0.07 per kWh. Annual electrical output of the system is estimated at approximately 1.1 million kWh annually.

As one can see, the impact of using more of the electricity on the farm has a positive impact on the NPV of the project. This is the result of off-setting retail purchases of electricity rather than selling electricity at the lower wholesale price received from the grid. As one uses more of the electricity in on-farm applications the average price received increases until it reaches the retail price at which point all energy produced is used on the farm. It is very important to understand that this does not mean that it is appropriate to increase on-farm energy use for the sake of utilizing AD generated electricity. If the farm has already optimized electrical use at these higher levels, the result indicates that greater on-farm utilization of AD electricity improves the return to the AD system. The total energy production of system was estimated at 1.1 million kWh per year and as a result increases in on-farm use of electricity beyond this level do not impact the NPV of the project. Additionally, because the NPV of the project remains negative even if all energy is utilized on the farm, the analysis indicates that it would be more economical to purchase the electricity from the grid.

The next analysis considers the impact of increasing biogas yields. This might be achieved through more intensive management of the biogas system. The biogas yield is the result of the variables for the percent of volatile solids converted to biogas, the amount of biogas produced per pound of volatile solid converted, and the BTU content of the gas. Rather than examining each of these factors independently, the gas production of the system was altered by increasing the total biogas output which could result from changing a variety of the factors simultaneously. For instance, in the base case the energy produced by the biogas resulted in 51,000 BTU's per cow lactating cow per day. The results of this analysis are shown in Table 13.

Table 13. Impact of Increasing Biogas Yields on AD System Profitability.[a]

Total Biogas Output (MMBTU's/yr)	BTU's per Lactating Cow per Day	Average Price Received ($'s/kWh)	Annual Energy Sales	NPV	% Change in NPV
16,907	51,000	0.1047	$ 116,710	-$180,014	0
18,597	56,100	0.1015	$ 124,515	-$100,987	44%
20,288	61,200	0.0989	$ 132,319	-$ 21,960	88%
20,758	62,617	0.0982	$ 134,488	$0	100%

[a] The analysis assumes annual on-farm energy consumption of 850 kWh per cow, $0.12 per kWh for retail electrical, and $0.07 per kWh for wholesale energy sales.

The analysis shows that biogas energy yield can have a substantial impact on the profitability of the system. In addition to energy sales, this factor influences the amount of performance and capacity incentives as energy production increases. The break-even NPV occurs when the biogas production per lactating cow reaches 62,617 BTU's per day, an increase of approximately 23 percent over the base assumption. As one can see, the average price received for electricity falls as a larger proportion of the electricity is sold at the wholesale price. However, the fact that one is selling more electricity increases the profitability of the operation. If the assumption of the annual energy use of the farm were also altered the economic performance of the system would also improve significantly. Table 14 shows the same analysis for biogas output but based on an annual on-farm energy usage of 1,000 kWh per cow per year.

Table 14. Impact of Increasing Biogas Yields with Annual On-Farm Energy Use of 1,000 kWh per Cow.[a]

Total Biogas Output (MMBTU's/yr)	BTU's per Lactating Cow per Day	Average Price Received ($'s/kWh)	Annual Energy Sales	NPV	% Change in NPV
16,907	51,000	0.1114	$124,210	-$ 133,930	
18,597	56,100	0.1076	$132,015	-$ 54,903	59%
20,288	61,200	0.1045	$139,819	$ 24,124	118%
21,979	66,300	0.1019	$147,623	$ 103,151	177%

[a] The analysis assumes annual on-farm energy consumption of 1,000 kWh per cow, $0.12 per kWh for retail electrical, and $0.07 per kWh for wholesale energy sales.

In this case one can see that that reaching a positive NPV occurs when biogas yield increases to 61,200 BTU's per lactating cow per day, an increase of 20 percent over the base case. Here, one is benefiting both from high amounts of energy production as well as selling a higher proportion of the energy production at retail prices.

As one would expect, yield and price have very important impacts on the economic viability of the AD system. The next analysis shows the impact of increasing the price received for electricity. In this analysis the retail and wholesale price are assumed to increase in equal proportions from a base of $0.12 per kWh for retail and $0.07 per kWh for wholesale (Table 15).

Table 15. Impact of Higher Electrical Prices on AD System Profitability.[a]

Price Increase From Base	Average Price Received ($'s/kWh)	Annual Energy Sales	NPV	% Change in NPV
0	0.1047	$ 116,710	-$ 180,014	
10%	0.1152	$ 128,381	-$ 108,300	40%
20%	0.1256	$ 140,052	-$ 36,587	73%
25%	0.1310	$ 146,007	$0	100%

[a] The analysis assumes a biogas energy yield of 51,000 BTU's per lactating cow per day and on-farm energy use of 850 kWh/cow/year.

The analysis in Table 15 shows that the average price received for the energy generated must equal $0.131 per kWh in order for the system to break-even at these production levels. This price could be achieved either through consuming all of the gas on the farm that faced these retail prices or through a combination of off-setting a higher on-farm retail price and a higher (than the base level) wholesale price. Were production to simultaneously change, the average price necessary to achieve a break-even would fall. In fact, according to Table 14, a positive NPV was achieved with an average price of $0.1045 per kWh when biogas energy yield was 61,200 BTU's per lactating cow per day.

Research has shown that co-digestion of food wastes with manure can increase biogas production dramatically (Scott and Ma). Table 16 shows how including alternative waste streams can impact the economic viability of the digestion system.

Table 16. Impact of Additional Waste Stream on AD System Profitability.[a].

Tons Per Day of Additional Waste	Average Price Received ($'s/kWh)	Annual Net Tipping Fees	Annual Energy Sales	NPV	% Change in NPV
0	0.1047	$0	$116,710	-$180,014	
3	0.1000	$10,950	$128,841	$ 10,109	106%
6	0.0965	$21,900	$140,972	$200,232	211%
9	0.0937	$32,850	$153,103	$390,355	317%
12	0.0914	$43,800	$165,234	$580,478	422%

[a] The analysis considers adding various amounts of an additional waste stream with 40% VS content, the same conversion rates to biogas as manure, $10 per ton net tipping fees, annual on-farm energy consumption of 850 kWh per cow, $0.12 per kWh for retail electrical, and $0.07 per kWh for wholesale energy sales. The analysis holds operating costs constant so should be interpreted with caution.

One can quickly see that the inclusion of additional waste streams can significantly impact the profitability of the system. The tipping fees dramatically improve the bottom line and adding a waste stream with a high volatile solid content increases the amount of electricity that can be produced by the system. Again, if this change were completed in concert with other changes, it would be possible to increase the economic viability of the operation considerably. However, it is also important to note that this analysis did not alter the operating costs of the system. It is clear that finding, negotiating, and handling these alternative waste streams would also come at a cost of time, labor, equipment, and management. These factors should be carefully considered in the analysis.

In summary, the base analysis of the economic return that can be expected from an AD system should lead one to proceed with caution. It is clear that the amount of energy produced, the price that is received for the energy, and the ability to include alternative waste streams in the digestion system significantly impact the economic viability of the system. However, it appears that with proper management and the ability to achieve favorable pricing AD systems can be quite economical.

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