6.0 ECONOMIC ANALYSIS

This chapter presents an economic analysis of two technologies for producing energy from manure - anaerobic digestion and direct combustion. The analysis consists of a pro forma income statement, based on several economic assumptions, and a sensitivity analysis for each of four manure digester sites and one manure-burning power plant. The pro forma income statements include calculations of the net present value (NPV), internal rate of return (IRR), and the levelized cost of construction and operation, all over a ten year period. The sensitivity analyses show the effects on the financial performance of each project by varying key assumptions, both singly and in groups.

Four sites to model manure digesters were chosen to reflect different geographical regions within the WRBEP area as well as three different digester technologies and two types of animal manure. Additionally, a single site was chosen to model a direct combustion facility. Table 6.1 shows the location, technology, capacity (kW), and manure types for each of the five models.

Table 6.1. Manure-to-Energy Facility Sites

Location	Technology	Capacity (kW)	Manure Types
South Dakota	Plug Flow Digester	35	Dairy cows
Nebraska	Complete-Mix Digester	101	Swine market
Texas	Covered Lagoon Digester	41	Dairy cows
California	Covered Lagoon Digester	81	Dairy cows
California	Direct Combustion	20,000	Dairy cows, feedlot cattle

The basic assumptions underlying each model are detailed in Section 6.1. These assumptions represent the "base case" set of conditions that are most likely to occur. Section 6.2 contains summaries and discussions of the pro forma income statements based on the basic assumptions. Finally, in Section 6.3, the results of a series of sensitivity analyses are detailed and discussed. The sensitivity analyses adjust major factors in the assumptions and measure their effects on the financial statistics of the model. Included in Section 6.3 is a brief analysis of the potential effects caused by the termination of guaranteed electric rates in California and the resumption of avoided cost rates.

6.1 Assumptions

The pro forma income statements were developed to model the feasibility of each of the five manure-powered energy projects. The basic economic and technical assumptions were formed to allow variations in location, economic conditions, and technology to permit modification of the model without the need to change the calculations. The assumptions are based on prior research and available data that best fit the technology and the location of the facility being modeled. Tables 6.2 through 6.6 detail the assumptions for each of the five manure-to-energy facilities. The figures in Tables 6.2 through 6.6 noted with a "#" are calculated figures. They are calculated using the other assumptions listed on each table. The text following Table 6.6 details the calculations, the assumptions upon which they are based and the data involved in each calculation. Additional notes and references for these tables are located in Appendices G-K.

Table 6.3. Assumptions for Nebraska Complete-Mix Digester Model

		Source
Hogs	10,000	
#Capacity	101 kW	
Installed Cost	$284,753	
O&M Costs		
Fixed	$13.20/kW/year	[1]
Variable	13 mills/kWh	[1]
Depreciation Method	Straight line	[4]
Equipment Life	10 years	[4]
#Equipment Salvage Value	$24,975	[5]
Electricity Prices		
Purchase	$0.067/kWh	[6][7]
Sell	$0.040/kWh	[6][7]
#Electricity Production	624,137 kWh/year	
#Total On-Farm Electricity Consumption	430,000 kWh/year	[12]
Available Waste Heat	1,950 Btu/kWh	[5]
Propane Heat Value	93,000 Btu/gallon	[5]
Propane Price	$0.75/gallon	[5]
Tax Rate	20%	
Inflation Rate	5%	
Discount Rate	9%	
Loan Interest Rate	9.25%	
Down Payment on Loan	33.3%	
Capacity Calculation Assumptions:		
Biogas Production	4.4 cft/animal/day	[10][3]
Biogas Heat Rate	650 Btu/cft biogas	[5]
Generator Efficiency	24 %	[5]
Conversion Factor	3,412 Btu/kWh	[16]
Capacity Reserve Adder	20 %	[5]
Electricity Production Calculation Assumptions:		
Availability Factor	85%	[5]

= Calculated Values
(Source and note references are located in Appendices G and I)

Appendix I: Explanation of Assumptions in Table 6.3 for Nebraska Complete-Mix Digester Model

Availability Factor: For this analysis it was assumed that the engine and generator were operating 85% of the time.

Available Waste Heat: Engines are water cooled. The heat not lost through the exhaust or as radiated but absorbed by the coolant is the available waste heat. The hot coolant is circulated through the manure within the digester to maintain an optimum biological temperature. The coolant can also be used to heat barns and other building interiors.

Biogas Heat Rate: For this analysis biogas is assumed to be 60% methane resulting is a heat rate of 600 Btu's per cubic foot.

Biogas Production: Biogas production is a function of, among other things, manure volume, manure temperature, air temperature, and manure moisture content. Typical biogas production per hog in Nebraska is 4.4 cft/animal/day.

Capacity: The electrical generating capacity of the biogas collection and combustion system per hour. Capacity is a function of the farm's animal population, the volume of biogas collected per day, the heat rate of the biogas, generator efficiency, capacity reserve adder factor, energy conversion factor, and hours of operation per day.

$$\text{Capacity (kW)} = [(\text{Animals})^*(\text{Biogas})^*(\text{Heat Rate})^*(0.24)^*(1.2)]/[(3{,}412)^*(24)]$$

Capacity Reserve Adder: To allow for future fluctuations in biogas production, the generator capacity was increased by 20%.

Conversion Factor: One kWh equals 3,412 Btu's.

Depreciation Method: Method used to depreciate the digester and related equipment. In this analysis Accelerated Cost Recovery System (ACRS) was used.

Discount Rate: A percentage term used to represent the time value of money. A ballpark calculation for the discount rate is the rate of inflation plus four percent. The average inflation rate for the past 30 years was five percent.

Down Payment on Loan: The percentage of the cost of capital expenditure that must be paid up-front. Small Business Administration loans require one-third down.

Electricity Prices: Electricity prices vary by location, rate schedule, and rate class, among other things. For example, prices in Nebraska average approximately 6.7 cents per kWh. Data on sell-back rates is limited. For this analysis, sell-back rates are approximately 60% of purchase rates.

Electricity Production: Electricity production for the complete-mix digester is a function of the farm's animal population, the volume of biogas collected per day, the heat rate of the biogas, generator efficiency, days per year of operation, availability factor, and energy conversion factor.

Electricity Production(kWh)=[(Animals)*(Biogas)*(Heat Rate)*(0.24)*(365)*(0.85)]/[3,412]

Equipment Life: Included to provide salvage value for income statement; set by ACRS at ten years.

Equipment Salvage Value: The major components of the digester systems are: the digester, engine, generator, building to house engine and generator, and concrete pad for manure collection. It is assumed that after the ten year life of the equipment, only the engine and generator will be of any value. Their value will be 20% of their original value. To determine their original value the figure of $1050 per kW capacity was used.

Generator Efficiency: Typically, an engine and generator are able to convert 24 to 30% of the potential energy in biogas into electrical energy. The remainder is lost through heat, motion, and other forms of energy. For this analysis, the generator efficiency is assumed to be 24%.

Hogs: This figure may be altered to represent the population of a swine operation.

Inflation Rate: Rate of long-term general price increases. Assumed to be five percent annually based on a 30 year average.

Installed Cost: There is little reliable data on the installation costs of complete-mix digesters. The cost of a similarly sized digester was used as a proxy for the cost of the Nebraska digester.

Loan Interest Rate: The rate charged by the lending institution for the use of their money. The interest for Small Business Administration loans are set at the prime rate plus 2.75%.

O&M Costs: There is little reliable data on operations and maintenance (O&M) costs for plug flow digesters. For this analysis, O&M costs were obtained from RTI's Biomass State-of-the-Art Assessment and used for all types of digesters. Fixed O&M costs do not vary with electrical production while variable O&M costs do.

Tax Rate: A general rate representing taxes on revenues of digester system operation.

Total On-Farm Electricity Consumption: The amount of electricity consumed on-farm. It is assumed to be 600 kWh per animal per year. Normally, this electricity is purchased from the local utility. The electricity produced by the digester system is intended to displace some or all of the purchased electricity.

On-Farm Animal Population

The type of animal manure to fuel the power plant was chosen for each location based on animals most representative of a particular area in the WRBEP region. In addition, the size of herd is considered as to whether sufficient animals will be available to provide manure to fuel a power plant.

The population of animals at each of the digester facilities represents a starting point for the remaining calculations. Depending on the location of the facility, the number of animals may be either a median or average for the particular type of animal. Varying the size of the herd on a farm will change the size and installation costs of the energy project. In general, increasing the size of the herd requires a larger digester and power plant, thus increasing the total cost. However, due to the effect of economies of scale, the percent increase in cost will not be as great as the percent increase in herd size. Conversely, a decrease in herd size will decrease the total cost of the project, but not by as much as the change in herd size. The concept of economies of scale is discussed in more detail later in the chapter.

It is not the intent of this study to determine the optimum herd size for profit maximization from the production of energy from manure. To do so would require more concrete data with fewer assumptions. As will be shown later, larger herds make a project more financially viable.

Further, and perhaps more significant, energy production is a secondary consideration for all farmers. A farmer will optimize his herd size to maximize his profits, according to economic theory. Optimum herd size for profit maximization and energy production maximization may be very different. For farm operations of a certain scale, the two goals may be parallel.

Capacity Calculations

The calculation of the electrical generating capacity for each of the manure digesters' engine-generator sets was based on a number of assumptions. All assumptions are held constant for the different projects except: the number of animals, the volume of biogas produced by the manure, and the efficiency of the manure collection process.

To calculate the capacity for the plug flow and complete-mix digesters the assumptions underlying the capacity calculations, noted previously in Tables 6.2 and 6.3, were entered into Equation 1 as follows:

Equation 1: Capacity Calculation for Plug Flow and Complete-Mix Digesters

$$\frac{\text{Animals} * \text{Biogas} * \text{Btu} * 0.24 * 1.2}{3{,}412 * 24} = \text{Capacity (kW)}$$

where:	Animals	=	Number of animals in herd.
	Biogas	=	Volume of biogas in cubic feet produced by each animal's manure per day. Assumed 100% collectable.
	Btu	=	Btu's per cubic foot of biogas. We assume the biogas to be 60% methane

		(with a heat rate of 1,000 Btu's per cubic foot), therefore the heat rate of biogas is 600 Btu per cubic foot.[30] Market hog biogas has a heat rate of 650 Btu/cft.[31]
0.24	=	Generator efficiency.[32]
1.2	=	Capacity reserve adder is a 20% addition to the capacity to allow for variations in the size of the herd and in biogas production over time.[33]
3,412	=	Energy conversion factor of 3,412 Btu's per kWh.
24	=	Number of hours in a day reduces the figure to a hourly rate, or capacity.

The basic capacity calculation for the covered lagoon digesters is the same as Equation 1 except for the addition of the manure collection efficiency factor. Manure collection efficiency will be discussed in the section on digesters. Equation 2 shows the capacity calculation for the covered lagoon digesters. Assumptions for Equation 1 hold for Equation 2.

Equation 2: Capacity Calculation for the Covered Lagoon Digesters

$$\frac{\text{Animals} * \text{Biogas} * \text{Btu} * 0.24 * 1.2 * 0.55}{3{,}412 * 24} = \text{Capacity (kW)}$$

where: 0.55 = The collectable manure, parlor waste water and feed apron waste, account for approximately 55% of the total manure.[34]

The volume of gas produced by each animal is dependent upon the type of animal and the amount and type of feed it eats. Typical biogas production from diary cow manure is 55 cubic feet per day.[35] In general, dairy cows in California produce more biogas than the national average.[36] For this study, California and Texas dairy cows produce 70 cubic feet of biogas per animal per day compared to 55 cubic feet for South Dakota. For the market hog farm model in Nebraska, each market hog produces 4.4 cubic feet of biogas per animal per day.[37]

The capacity reserve adder increases the size of the engine-generator set by 20% to allow for variations of the size of the herd and gas production. This increase in capacity creates additional costs for the project. There is a direct relationship between the capacity reserve adder and manure collection efficiency. For the covered lagoon digesters there are two factors that may increase biogas production. Adding 20% to the capacity to allow for the first factor, herd growth, also allows for the second factor, improvement in the manure collection efficiency. For example, the capacity of the California digester including the additional 20% capacity is 81 kW. The actual capacity required based on the herd size (that is without the capacity adder) is 68 kW. If the manure collection efficiency improved from 55% to 65%, the capacity required to handle the increased amount of biogas produced would be 81 kW. This would leave no additional capacity to allow for herd growth.

Installation Costs

Installation costs are the costs for engineering design, obtaining permits, and installation of the necessary equipment including labor, equipment, and materials. Each technology has a different cost-per-kW capacity due to variations of design, amount and cost of materials, and amount of labor involved in construction. There are trade-offs between the cost of construction and the amount of energy produced and the amount of labor needed to operate the facility on a day-to-day basis. However, it is not necessarily true that the less expensive a system is to build, the less energy it produces or the more labor intensive it is to operate.

Manure Digester Costs

Three types of manure digesters are included in this economic analysis. Data for the total costs of installing digesters was obtained from several sources. All cost data was converted to a 1991 base year dollar amount by multiplying each by a price inflator. Finally, the total cost figures are divided by the capacity of the project, in kWs, to give an easily comparable cost per kW figure. Two methods were used to derive cost data for the four digester projects in this study. The first was to graph the cost-per-kW figures for each type of digester and then "eyeball" an appropriate cost per kW based on the previously calculated capacity. The other method used regression analysis of the cost data with capacity as the independent, or explanatory, variable. With this method, the capacity, in kW, was entered into the resulting equation to give a cost per kW for each model.

Cost Graphing

Graphing the cost-per-kW data and then "eyeballing" a cost to match the capacity for each of the three types of digesters results in a cost figure that is, at best, an approximation. Figures 6.1 and 6.2 plot the installed cost per kW capacity in 1991 dollars for plug flow and covered lagoon digesters, respectively. The project capacities used in this study are indicated by vertical lines. Choosing a cost-per-kW figure could result in a wide range of values.

In general, as the capacity of the project increases the cost per kW decreases. There are two possible explanations for this fact. First, improvements in technology may make digester facilities less costly over time. Second, as the capacity of the digester facilities increase they become less costly to build on a per-kW basis. The latter explanation is referred to as economies of scale.

If costs are decreasing over time due to technological advances, trying to estimate cost per-kW graphically from data without regards to when the facility was built will give unreliable estimates. If there is no technological influence on cost, then there is much less error in graphical estimations of per-kW costs. To test whether costs have changed over time due to technological advancement, it is necessary to determine what correlation exists between historical project costs and the year the projects were built. By analyzing the sample data of plug flow digesters, by means of econometric methods, it can be shown that there exists very little correlation between cost per kW and the year of project. The value of the correlation coefficient (r) is -0.047. The negative sign indicates that installed costs per kW have fallen over time, however the degree of decline has been minimal. The size of the sample and the near zero correlation coefficient demonstrate that there is little statistical evidence to support the explanation of costs decreasing over time due to improvements in technology. This finding corroborates opinions of those within the biomass industry.[38] There is insufficient data to perform the same test for either the complete-mix or covered lagoon digesters.

Regression Analysis

A more precise method of estimating the installed cost per kW is by regression analysis. The installed cost data was used as the dependent variable and capacity as the independent variable. Estimates of installation costs for three of the four digester models are calculated by plugging the capacities, in kWs, into the resulting equations. There is sufficient data for both the plug flow and covered lagoon digesters to derive statistically sound estimates using this method. However, there was insufficient data to do so for the complete-mix digester.

A problem arose while trying to determine the proper equation, or functional form, for the regression. If lines were drawn on Figures 6.1 and 6.2 to best represent the plotted data, the best fit of the data would be curves rather than straight lines. The concept of economies of scale leads to a curvilinear fit for both technologies. Data, such as generating capacity, can be transformed to render a data plot that is easier to model with a straight line regression. This method of finding the best fit is not as complex as logarithmic and exponential regression equations.

Taking the inverse of capacity and plotting the data leads to a straighter and less trended data plot than those in Figures 6.1 and 6.2. Estimating the regression using a straight line equation with the inverse independent variable led to a cost estimate for the plug flow digester with an R-squared of 0.62 and an estimate for covered lagoon digesters with an R-squared of 0.73. The R-squared statistic measures the percent variation in the dependent variable, installed cost per kW, explained by the variation in the independent variable, the inverse of capacity. Given the size of the data sets (26 and 11 observations for the plug flow and lagoon models, respectively) and the simplicity of the models, these R-squares indicate sound models. Equations 3 and 4 show the resulting regression equations for plug flow and covered lagoon digesters, respectively.

Equation 3: Regression Equation for the Plug Flow Digester

$$\text{Installed Cost per kW (Plug Flow)} = \$1960.00 + \$75447.00 * \frac{1}{\text{kW}} \qquad (R^2 = 0.62)$$

Equation 4: Regression Equation for the Covered Lagoon Digester

$$\text{Installed Cost per kW (Lagoon)} = \$1834.60 + \$52863.50 * \frac{1}{\text{kW}} \qquad (R^2 = 0.73)$$

From this point it is necessary only to take the capacity for each of the plug flow and lagoon digesters and insert them into the equations to calculate an installed cost per kW in 1991 dollars. Multiplying the installed cost per kW by the capacity results in an estimate of the total installed cost for each project.

The regression method of cost estimation is more reliable than "eyeballing" a cost from the graphs, and renders more viable estimates for the plug flow and lagoon digesters. Due to the

Figure 6.1. Installed Cost per kW: Plug Flow Digesters

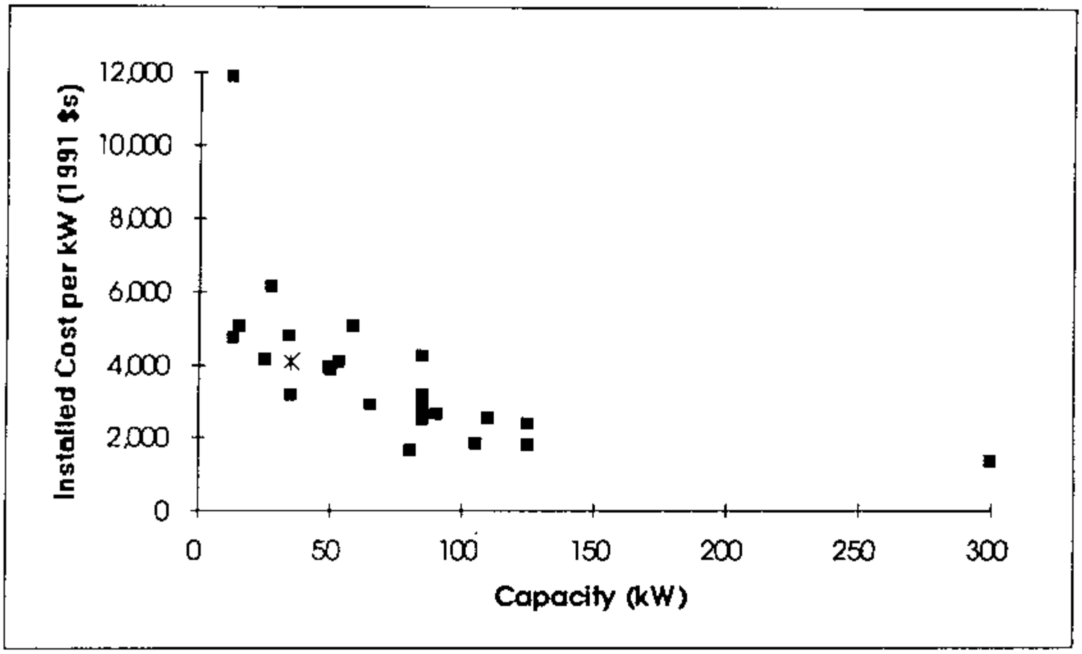
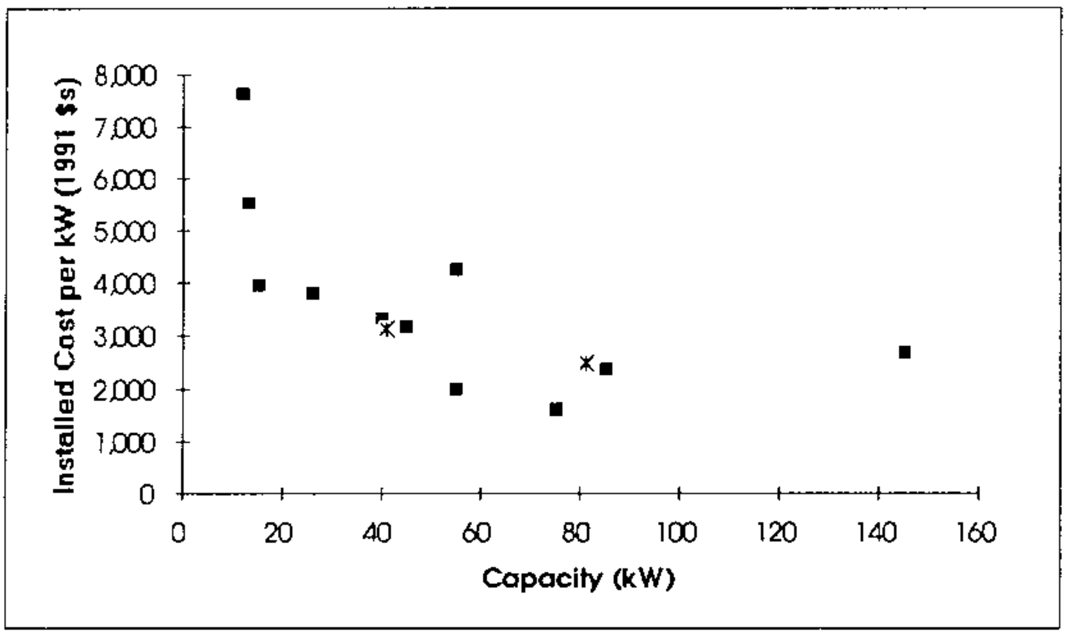


Figure 6.2. Installed Cost per kW: Covered Lagoon Digesters



scarcity of data for the complete-mix digester, the cost data were derived from data for a similarly sized complete-mix digester.[39] The cost of installing a digester depends on the type of technology used. The digester installed costs on a per kW basis for the three types of digesters in this study are (from lowest to highest): covered lagoon, plug flow, and complete-mix. This is due to the covered lagoon digesters requiring the least materials and construction, and complete-mix digesters requiring the most.

Operations and Maintenance Costs

Data for the costs of operating and maintaining manure digester systems are site specific. Factors such as: weather, quality of design, construction, and materials; and mechanical knowledge of the operator all influence operations and maintenance (O&M) costs. Since the economic models are for hypothetical projects, the same O&M cost figure is used for all four digester models.

There is a wide variation in estimates for O&M costs. Some estimates are based on a percentage of the capital cost (installed cost) annually, which may or may not include additional labor costs. Other estimates were extrapolated from the O&M costs for operating digester facilities.[40] However, the amount of data available to base these estimates on is very small and the variations large. Because of the large variations in estimates, it was difficult to ascertain an estimate for a "normally operating" facility. As mentioned above, there are many factors influencing O&M costs. Understanding which factors have affected any given digester operation is impossible, therefore knowing the plausibility of a given estimate is impossible. Ultimately, estimates for O&M costs were obtained from RTI's Biomass State-of-the-Art Assessment. Inflating RTI's O&M figures to 1991 values gave total O&M costs (including fixed and variable costs) of approximately \$0.015/kWh for each of the four digester facilities. This figure is in line with reported O&M costs from operating digesters. Again, the true cost figures will vary due to a multitude of factors.

The cost of fuel for the digesters is assumed to be zero since the manure comes from the farm itself. It is further assumed that there is a negative fuel cost to the farm operator by not having to pay for manure disposal. This savings is reflected in the income section of the pro forma income statements and will be discussed in more detail in the next section.

The O&M figures for the direct combustion facility are based on the reported O&M costs for power plants of similar size.[41] Due to the additional costs of acquiring, transporting, and storing the manure fuel, the total O&M costs for the direct combustion power plant are approximately \$0.026/kWh. Because the cost of fuel is a large part of the costs of operation, the fixed and variable costs of operation decrease. Again, as for the cost of building a power plant, economies of scale lead to decreasing per unit costs for larger plants. In this case, the total O&M costs for the direct combustion plant were about \$0.011/kWh *not including the cost of fuel*. This represents, approximately, a 27% decrease in total O&M costs from the digester facilities.

Energy Conversion Technology

The fuel for the digesters and the direct combustion facility is animal manure. The costs of transporting, handling, and storing the manure affect the economics of the power plant. Dairy manure has a different per kW cost than does market hog manure.

<u>*Digesters*</u>

The digester facilities and engine-generator sets are sized to accommodate the volume of manure and biogas that can be produced on-site. Up to this point, manure has been a waste problem that requires disposal. For this study, the methods of manure elimination are hauling, scraping, or flushing.

Hauling the manure away by truck is used at the South Dakota facility. The hauling is performed by a trucking company which charges a ton-per-mile fee. The cost of hauling, shouldered by the farm or dairy operator, is assumed to be $24/cow/year in 1991 dollars.[42] Since the manure will be fed into the digester, there is no longer a need for disposal. Disposal, which has been an expense until now, becomes a savings which appears as revenue to the farm operator. One hundred percent of the manure will be collected and placed in the digester. This is most often achieved by scraping the manure from the apron and feedlanes daily. The manure is then mixed with sufficient water to make the resulting slurry semi-solid so no separation of liquid and solids occurs. Daily manure production is assumed to be 14 pounds of total solids per animal per day. The manure has a moisture content of 87%, resulting in a daily per animal manure production of 108 pounds.[43]

The Nebraska complete-mix digester is located on a farrow-to-finish hog farm using under-floor scrapers or pull-plugs to move the manure from the building into a lagoon or pond. Typically, the manure solids settle in the lagoon and the liquid is used to irrigate fields. Little biogas is produced in the lagoon because the average yearly temperatures in Nebraska are too low to foster biogas production. A heated plug flow digester is not an option, either, because there are too few manure solids in the lagoon effluent to prevent the manure solids from settling. A complete-mix digester can be heated and the constant mixing prohibits the settling of the manure solids.

Manure is collected at the two covered lagoon digesters by periodic scraping of the apron and feedlane and daily flushing of the milking parlor with water. For the Texas and California facilities it is assumed that the manure removed from the apron and parlor accounts for approximately 55% of the manure produced at the farm. The remaining 45% of the manure, located on dirt drylots or other areas, is not feasible to regularly remove.[44] Uncollected manure, left too long, becomes dry and loses its capacity to produce biogas. Dairy cows in Texas and California are assumed to produce 15.6 and 15 pounds, respectively, of total solids per animal per day. Assuming 87% moisture content and 40% of the farm's total manure collected from the apron, 48 and 46 pounds per animal, respectively, of manure need to be disposed of daily.

The byproducts of the digester process, namely the digested solids and liquids, can be disposed of in many ways. The solids can be used for animal bedding material or soil amendment. For the South Dakota facility analysis, it is assumed that the digested solids will be used as soil amendment with a value of $2,000 annually.[45] The Nebraska digester and the two lagoon digesters will not use the digester byproducts for beneficial use. The liquids are easily used for irrigation but are assumed to have no monetary value in this analysis. The manure, which once was a disposal liability, can become a product available for resale or use on the farm at a savings.

Direct Combustion

The sizing of the direct combustion facility is more difficult than that of the digesters because it is dependent on the amount of manure available in the area. The amount of manure available is further subject to any seasonal variations which would require the availability of a sufficient manure storage area. On-site storage must be sized to allow operation of the power plant during periods of low manure production or extended intervals between manure deliveries. If one determines that there is sufficient manure resources to warrant a given power plant size, the next step is procuring manure supply contracts. The assumed manure cost in the model is derived from a similarly sized manure fueled power plant in California. The manure is collected free of charge from the dairies and feedlots. The cost includes transporting, handling, processing, and storing the manure.

The moisture content of manure determines the amount of power derived from its combustion. A low moisture content gives a greater percent of combustible material per ton of manure. This implies a higher heat rate and more power resulting from the combustion of drier manure. The power plant operator has little control over the moisture content and manure quality if the manure drying process takes place at the farms and feedlots. Drying the manure at the power plant site requires a large area to permit a continual rotation of newly arrived, drying, and ready-to-burn manures. The climate at the power plant dictates the measures which must be taken and the length of time needed to allow proper drying of the manure. The California facility is assumed to have sufficient area for on-site manure drying.

The byproduct of the direct combustion process is ash. The single operating manure burning power plant reports manure ash content of 17% by weight. Generally, there is little demand for ash and, consequently, it must be disposed of in landfills. Ash is difficult to transport and store and it accumulates quickly. Some wood-fueled biomass power plants are presently marketing non-hazardous ash for uses such as soil amendment, absorbent, and road surfacing material. For the facility in this study it is assumed that the ash will be marketed as soil amendment at the wholesale and retail levels. Because an exact market value is unknown, we assume that 10% of the total ash produced will be sold at $5 per ton. This value is similar to the market values from other power plants selling their ash. The remainder will be disposed of at a landfill. The cost for disposal of the remaining ash was not included in the analysis.

Depreciation Method and Salvage Values

The method used to depreciate the installed cost of the power plants is the straight line method. The purpose of these economic analyses is to determine the feasibility of some hypothetical power plants. Since taxes are not a significant consideration in these analyses, a tax depreciation scheme such as the Modified Accelerated Cost Recovery System is not required. It was anticipated that the equipment life for the digester, engine, generator, and related equipment was ten years. It is assumed that the power plant began operation on January 1, thus each calendar year receives a full 10% depreciation expense.

The salvage value of the equipment for all the digester power plants, except the Nebraska facility, is estimated to be 20% of the original cost the engine and generator sets. The original cost of the engine and generator sets is assumed to be $1,050/kW. This cost does not include labor, installation materials, or structures. The salvage value of the Nebraska complete-mix digester is assumed to be 10% of the installed cost. The complete-mix digester is different than the plug flow and lagoon digesters in that the digester itself is salvageable. The salvage value of the direct combustion equipment includes all physical plant which is assumed to be 20% of the installed cost.

Electricity Prices

The prices for buying and selling electricity are the most difficult to generalize of all the assumptions. Prices vary by location, season, demand, utility service territory, and time-of-day. In one study, the cost of electricity, including milking, barn heating, and pumping the water to irrigate the feed at a dairy located in the San Joaquin Valley of California, was approximately 3.8% of the total cost of production per cow.[46] Any decrease in the cost of electricity would increase the profit margin of the dairy farmer. Being able to produce one's own energy at a lower cost than purchasing from the utility could give a competitive boost to the operator of the dairy facility. Basically, the assumed prices are generalized for the location and size of each power plant.

__Buying Electricity__

The types of digesters discussed in this study are designed to use no-cost manure. The cost of taking advantage of this source of energy includes; designing, building, and operating the digester facility. The current price of electricity must be sufficiently high to then consider the cost of building the digester system. The operator must decide if a digester power plant can be built and operated for less than the cost of purchasing energy for the next ten years.

The cost of electricity varies by geographical region, the time of year it is consumed, how much is being consumed at any instant, the time of day it is consumed, and even by the willingness of the consumer to have service interrupted or cut back by the utility. Table 6.7 shows an average price that could be expected in the areas near the power plants. Depending on the local utility, a demand charge may exist. If there is, there may be a threshold below which the demand charge is zero, as is assumed to be the case with the South Dakota and Nebraska digesters. With the increasing popularity and use of equi-proportional marginal cost (EPMC) pricing of electricity, there is more pressure on the agricultural electricity user to be more economical and flexible in his energy use. In California, the move towards full EPMC based prices signifies an increase in electric rates for agricultural users due to the phase-out of historical subsidies by other rate classes.

As agricultural electricity rates increase, they will improve pro forma income statement results. Higher prices equate with greater savings, which are treated as revenues in the income statements. As revenues increase, so does the economic vitality of each project.

Selling Electricity

Operators of manure fueled power plants with surplus electricity may be able to sell the excess power to local utilities. Each state's and utility's requirements and prices will vary, but, if it is possible, the added revenue will increase the viability of the power plant. As can be seen in Table 6.7, sell back rates are nearly 60% of purchase rates. However, the rates in many areas can be significantly less. Usually, the sell back price is a representation of the utility's avoided cost of building additional capacity or generating the additional kWh. In California, the sell back price varies depending on when the contract stating the utility's willingness to buy the excess power was signed. The current selling price of a guaranteed rate contract signed under a Standard Offer 4 (SO4) schedule in late 1982 would be almost ten cents per kWh. However, for a new contract in 1992 the current avoided cost-based selling price would be approximately 3.5 cents per kWh.

The plug flow and complete-mix digesters in this study produce more electricity than is consumed on the farm. On the other hand, the two covered lagoon digesters produce less electricity than is consumed due to the low manure collection efficiencies. The direct combustion power plant consumes only a negligible amount of power on-site which is used to keep ancillary systems operating. Therefore, as is shown in Table 6.7, it would not be built to provide power for on-site consumption but to provide power to sold on a wholesale basis to a utility.

Table 6.7. Electricity Purchase and Sell Prices Including Energy and Demand/Capacity

Location & Technology	Purchase		Sell	
	Energy ($/kWh)	Demand ($/kW/yr)	Energy ($/kWh)	Capacity ($/kW/yr.)
South Dakota Plug Flow Digester	0.075	N/A	0.045	N/A
Nebraska Complete-Mix Digester	0.067	N/A	0.04	N/A
Texas Covered Lagoon Digester	0.036	95.76	0.022	46.69
Texas Covered Lagoon Digester	0.036	95.76	0.022	46.69
California Direct Combustion	N/A	N/A	0.035	56

Sources: Envirosphere Co./Arthur Young and Co. 1983.
Biomass State-of-the-Art Assessment, Volume 1: Guide, EPRI 1990.
Pacific Gas & Electric Company 1990.
NEOS Corporation, California Biomass Facilities Surveys, 1990.
Meri Hanson, California Public Utility Commission, 1992.

Electricity Calculations

Electricity Production

Equations 5 and 6 are used to determine the electricity produced by the plug flow and covered lagoon digesters, respectively. Equations 5 and 6 are similar to Equations 1 and 2, except there is no capacity reserve adder, the resulting value is for an entire year, and an availability factor is included. The availability factor is the percentage of time the power plant is in operation. A power plant may be inoperable due to regularly scheduled maintenance, equipment breakdown, or unfavorable economic operating conditions. In the case of the four digester power plants, the assumed availability factor is 85%. This figure varies with the amount and quality of regular maintenance and attention given to the operation of the digester and engine-generator set. The direct combustion facility in California has an assumed availability factor of 80%. This figure is based on data collected from the operators of a similar facility already operating in California. This lower figure reflects its mechanical complexity and unique fuel.

The energy production calculation in Equation 5 is for the plug flow digester in South Dakota and the complete-mix digester in Nebraska. It calculates the number of kWhs produced annually.

Equation 5: Energy Production Calculation for the Plug Flow Digester

$$\frac{\text{Animals} * \text{Biogas} * \text{Btu} * 0.24 * 365 * 0.85}{3{,}412} = \text{Electricity Produced (kWh)}$$

where:	Animals	=	Number of animals in herd.
	Biogas	=	Volume of biogas in cubic feet produced by each animal's manure per day. Assumed 100% collectable.
	Btu	=	Btu's per cubic foot of biogas. We assume the biogas to be 60% methane (with a heat rate of 1,000 Btu's per cubic foot), therefore the heat rate of biogas is 600 Btu per cubic foot. Market hog biogas has a heat rate of 650 Btu/cft.
	0.24	=	Generator efficiency. per kWh.
	365	=	Days in a year
	0.85	=	Availability Factor
	24	=	Number of hours in a day reduces the figure to a hourly rate, or capacity.
	365	=	Days in a year.
	3,412	=	Energy conversion factor of 3,412 Btu's per kWh.

Equation 6, the energy calculation for the two covered lagoon digesters in Texas and California includes the manure collection efficiency figure as in Equation 2. The assumptions are the same as for Equation 5, except for the addition of the manure collection factor.

Equation 6: Energy Production Calculation for Covered Lagoon Digesters

$$\frac{\text{Animals} * \text{Biogas} * \text{Btu} * 0.24 * 0.55 * 365 * 0.85}{3{,}412} = \text{Electricity Produced (kWh)}$$

where: 0.55 = The collectable manure, parlor waste water and feed apron waste, account for approximately 55% of the total manure.

As with calculating the capacity, the amount of energy produced by the covered lagoon digesters can be increased considerably by increasing the manure collection efficiency. Increasing the collection efficiency from 55% to 65% increases the number of kWh produced by over 18%. The manure collection efficiency of 55% is an assumed average. Dairies will exist with higher efficiencies and therefore have an improved financial statement. Collection efficiency can have a large influence on the financial success of the project.

Electricity Consumption

The amount of electricity consumed on-site per animal is derived from available data. For dairy cows, the data for kWh consumed range from one to two kWh/cow/day. One utility memorandum estimates a 688 kWh/cow/year consumption figure which is much higher than a case study of two California dairies which had consumption figures of 557 and 421 kWh/cow/year. For the California covered lagoon and South Dakota plug flow digesters, an on-farm electricity consumption of 600 kWh/cow/year was used to reflect these figures. For the Texas covered lagoon digester, 535 kWh/cow/year was assumed.

The Nebraska complete-mix digester is to be fueled by hog manure from a farrow-to-finish hog farm. A large market hog farm in California, which installed a cover over a portion of its lagoon, reported a consumption of 43 kWh/hog/year. We assume consumption for the Nebraska facility will be the same. Energy consumption, per-hog, in Nebraska may be higher than in California. However, there is no data or literature to confirm this.

Financial and Economic Rates

The financial and economic assumptions made in this study are the most important in terms of the sensitivity analysis. The farm operator has no control over the changing financial and economic conditions such as the tax rates, inflation rate, and discount rate. The operator must wait for any or all of the rates to become more favorable. The interest rates on commercial loans are more controllable as one can shop around for the best rate. However, there will be little variation among available rates as banks and lending institutions compete for borrowers.

The mean annual growth in the Gross Domestic Product (GDP) between 1960 and 1991 was 4.68%. For this study we assume the inflation rate to be 5% annually, based on the GDP growth.

For this study, the projects are to be funded by borrowing. A borrower has the most control over the down payment on a loan. Government loans and grants are available for small businesses at favorable interest rates. The Small Business Administration (SBA), the largest source of small business funding in the country, helps the borrower by offering guaranteed loans. The SBA will guarantee a certain percentage of the loan up to $750,000. The loans are made by private lenders and there is no maximum loan amount. Currently, the maximum allowable interest rates on SBA loans are the prime rate plus 2.25% for loans of less than seven years and prime plus 2.75% for loan over seven years. The economic analysis for this study assumes a prime rate of 6.5% and a loan of ten years resulting in a loan rate of 9.25%.

The down payment and interest rate on a loan are generally negotiated between the lender and the borrower. For the SBA loans, the borrower's contribution to capital must be one-third of the total project costs. Therefore, for this analysis, the SBA loan is no more than two-thirds the total installed cost of the project, thus the borrower's down payment is one-third or 33.3%. the down payment for the California manure burning power plant is also assumed to be 33.3% despite its high installed cost. As will be seen later, the size of the down payment has little affect on the NPV of the project. In fact, reducing the down payment to zero decreases the NPV by only two-thirds of one percent or $220,000.

6.2 Pro Forma Income Statement Analysis

The pro forma income statements developed for each of the power plants cover the first ten years of the power plant's life. Tables 6.9 through 6.13 show the income statements resulting from use of the basic assumptions discussed in the previous section and shown in detail in Tables 6.2 through 6.6. Table 6.8 summarizes the significant financial information from Tables 6.2 through 6.6 and 6.9 through 6.13.

Table 6.8. Summary of Assumptions and Income Statements for Manure-Fueled Power Plants

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester	California Combustion Power Plant
Capacity (kW)	35	101	41	81	20,000
Yearly Energy Production (kWh)	216,047	624,137	252,055	504,111	115,632,000
Installed Cost	$144,047	$249,753	$128,082	$201,466	$60,000,000
Net Present Value	$43,484	$14,167	($8,857)	$48,772	($33,365,506)
Internal Rate of Return	21.51%	10.27%	3.96%	21.36%	-21.44%
Levelized Cost ($/kWh)	$0.1126	$0.0693	$0.0847	$0.0767	$0.0847

Table 6.10. Pro Forma Income Statement for Nebraska Complete-Mix Manure Digester

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Income										
Electricity Savings	$28,810	$30,251	$31,763	$33,351	$35,019	$36,770	$38,608	$40,539	$42,565	$44,694
Surplus Electricity	7,765	8,154	8,561	8,990	9,439	9,911	10,406	10,927	11,473	12,047
Heat Savings	5,889	6,183	6,493	6,817	7,158	7,516	7,892	8,286	8,701	9,136
Total	42,465	44,588	46,817	49,158	51,616	54,197	56,907	59,752	62,739	65,876
Expenses										
Interest	15,409	14,407	13,312	12,116	10,809	9,381	7,822	6,118	4,256	2,222
Fixed O+M	1,333	1,400	1,470	1,543	1,621	1,702	1,787	1,876	1,970	2,068
Variable O+M	8,114	8,519	8,945	9,393	9,862	10,355	10,873	11,417	11,988	12,587
Total	24,856	24,326	23,727	23,052	22,292	21,438	20,481	19,410	18,213	16,877
Operating Income	17,608	20,261	23,090	26,106	29,324	32,758	36,425	40,341	44,526	48,999
Less: Depreciation	22,478	22,478	22,478	22,478	22,478	22,478	22,478	22,478	22,478	22,478
Pretax Income	(4,869)	(2,216)	612	3,628	6,846	10,281	13,947	17,864	22,048	26,521
Income Taxes	0	0	122	726	1,369	2,056	2,789	3,573	4,410	5,304
Net Income	(4,869)	(2,216)	490	2,903	5,477	8,224	11,158	14,291	17,639	21,217
Cash Flow										
Net Income	(4,869)	(2,216)	490	2,903	5,477	8,224	11,158	14,291	17,639	21,217
Depreciation	22,478	22,478	22,478	22,478	22,478	22,478	22,478	22,478	22,478	22,478
Salvage Value										24,975
Less: Repayment to Capital	10,835	11,837	12,932	14,128	15,435	16,862	18,422	20,126	21,988	24,022
Net Cash Flow	$6,774	$8,425	$10,036	$11,253	$12,520	$13,840	$15,214	$16,643	$18,129	$44,648
Present Value of Net Cash Flow	$6,774	$7,729	$8,447	$8,689	$8,870	$8,995	$9,071	$9,104	$9,098	$20,557

Net Present Value:	$14,167	Levelized Cost:	$0.0693 /kWh
IRR:	10.27%		

The Income Statement by Section

Income: Includes all revenues, both real and apparent, received by the operator of the power plant. Revenues are categorized into the following sources.

Electricity Savings: Apparent revenue created by no longer having to pay for electricity. The product of electricity purchase price and on-farm electricity consumption. Demand charges are included for the lagoon digesters because of their size.

Surplus Electricity Sales: Real revenue created by selling excess energy to a local utility. The product of the difference between energy produced and energy consumed on-farm and the sell back price of electricity.

Manure Disposal Savings: (South Dakota Plug Flow Digester only.) Apparent revenue from discontinuing manure disposal. The product of manure produced per animal, number of animals, and the cost of disposal. Assumed to be $24.00 per cow per year.

Heat Savings: Cost of forgone propane purchases due to the substitution of waste heat from the engine. Propane is assumed to have a heat content of 93,000 Btu per gallon. The price of propane is assumed to be $0.75 per gallon. The available waste engine heat is valued according to these two figures.

Digester Byproduct Savings: (South Dakota Plug Flow Digester only.) Some of the solid byproducts of the digestion process can be used as soil amendment. They are substituted for chemical and other soil amendments. The annual savings of $2,000 are treated as revenues.

Ash Sales: (California Direct Combustion facility only.) Revenues from the sale of ash as detailed in section 6.1.

Expenses: Includes interest charges on the loan as well as fixed and variable O&M costs. The cost of manure transportation, handling, processing, and storing is included in the California Direct Combustion facility's expenses.

Operating Expenses: Income less Expenses.

Pretax Income: Operating Income less Depreciation.

Net Cash Flow: Sum of Net Income, Depreciation, salvage value (in the tenth year), and repayment to capital which is the portion of the year's loan payment that goes toward paying off the principal.

Net Present Value (NPV): The sum of the present values from each year minus the operator's initial investment. It is the single most important investment criteria. A financing rule of thumb is to accept a project if it has a positive net present value.

Internal Rate of Return (IRR): The percentage rate at which the net present value of the net cash flows is equal to the present value of the initial investment. The initial investment in this case is the amount the farm operator pays (the down payment) towards the installed cost of the power plant. The rule for capital budgeting on the basis of the internal rate of return is to accept an investment project if the internal rate of return is greater than the discount rate.

Levelized Cost: The cost of building and operating the power plant over the first ten years of its life per kWh. Calculated by summing the total expenses, taxes, loan payments, and depreciation for each year and determining the net present value then dividing by the total kWhs produced during the ten year period. The levelized cost will vary as the size of the down payment changes (which will be discussed in detail later) because the principal and interest payments change.

The Power Plant Income Statements

Tables 6.9 through 6.13 detail the income statements for each of the manure-fueled power plants based on the assumptions stated in Tables 6.2 through 6.6. Table 6.8 summarizes the important assumptions and figures for each power plant.

South Dakota Plug Flow Digester (Tables 6.2 and 6.9)

Based on the assumptions in Table 6.2 the plug flow digester located in South Dakota has a NPV of $43,484 and an IRR of 21.51%. As detailed in Table 6.8, the levelized cost of building and operating the digester for the first ten years is $0.1226/kWh. This is the highest levelized cost of the five power plants.

Levelized cost is heavily influenced by the debt load of the power plant's owner. Typically, for the power plants modeled, loan payments were almost one-half of annual operating expenses. Depreciation was approximately one-third of annual operating expenses. The remainder was O&M costs, taxes, and purchases of additional electricity. The South Dakota Plug Flow digester had the highest installed cost on a per-kW-basis. It was also the smallest of the power plants. This means that for its power generating ability it has the highest debt load. It has to generate more electricity over the long-run or generate electricity more cheaply than alternative sources. Had the power plant been larger, its levelized cost would have decreased.

Nebraska Complete-Mix Digester (Tables 6.3 and 6.10)

The NPV of the complete-mix digester is $14,167, the levelized cost is $0.0693/kWh for ten years, and the IRR is 10.27%.

This project's problems stem from the fact that complete-mix digesters are the most expensive to build, per kW. In addition, the farm is assumed to be a farrow-to-finish hog farm. Hog manure is very low is total solids. Because of this, the only types of digesters that could be used are a mixed digester, such as the complete-mix, and a covered lagoon digester. Putting a cover over the lagoon captures the escaping biogas. However, a lagoon cannot be heated and the temperatures in Nebraska are too cold during the winter to sustain digestion. Thus the only alternative is the mixed-tank digester. Since the manure was assumed to have been scraped into a lagoon previously, there is no manure disposal savings to boost the revenue figures.

6.3 Sensitivity Analysis

Sensitivity analysis measures the change in a major statistic caused by the change in an assumption. For this analysis, the percent change from the base case brought about by 10% increases and decreases in an assumption will indicate which assumption has the most influence on the financial viability of a project. The effects on the NPV, IRR, and levelized cost caused by altering the discount rate, down payment, inflation rate, interest rate, and installed cost are analyzed by changing one factor at a time. Multiple-factor sensitivity analyses are performed to measure the effects of the most likely combination of variations in assumptions because it is more likely that many assumptions change at one time.

Single Factor Analysis

Single factor analysis is a sensitivity analysis varying one factor at a time. By keeping the other assumptions constant, the change in the major financial figures resulting from 10% increases and decreases in a single assumption were measured as a percent change from the base case. Tables 6.14, 6.15, and 6.16 show these effects on NPV, IRR, and levelized cost, respectively. In each table, the base value of the figure for each of the five power plants are listed at the top of each column. The five assumptions varied for the analysis are listed underneath with the values resulting from the low (10% decrease) and high (10% increase) variations in that assumption. Beside each resulting value, in parentheses, is the percent change from the base value at the top of the column. The percent change figures may vary due to rounding.

Each of the five assumptions will have an effect on the three financial figures for a different reason. They will also have differing proportional effects. As referred to above, the reason for the sensitivity analysis is to determine which assumptions have the greatest effect.

Discount Rate

The discount rate represents the time value of money or the opportunity cost of capital. It is called the opportunity cost because it is the return forgone by investing in the project rather than investing in another option such as securities. The discount rate is used to "discount" a future cash flow to present value. It has no effect on the IRR because the IRR is calculated using the non-discounted cash flows. The NPV and levelized cost figures are affected by the discount rate. Decreasing the discount rate increases the present value of future cash flows resulting in a higher NPV.

Down Payment

Varying the size of the down payment changes the amount of capital borrowed. Increasing the down payment lowers the principal and the interest payments which lower the total costs of operation. For this reason, it would appear at first glance, that increasing the down payment raises the IRR. However, increasing the down payment also increases the initial investment the farm operator makes, and though the net cash flows increase due to the lower costs, the increases are not sufficient to make up for the increased initial investment. Increasing the down payment *decreases* the IRR and NPV. The levelized cost decreases with an increase in down payment because the operating costs are decreased. The converse holds true for all three cases.

The down payment can affect implicit factors such as the farmer's opportunity costs of borrowing money. The farmer may decide that the opportunity cost of using his own money is too high, therefore, he borrows money. For example, if the loan interest rate is 10% and his opportunity cost is 15%, he should borrow money rather than use his own. In this situation the farmer should opt for a smaller down payment and larger loan for a given investment. The smaller down payment results in increased loan payments with the same effects on NPV, IRR, and levelized cost as noted above.

Inflation Rate

Only the operating income portions of the pro forma income statements are affected by the inflation rate. Therefore, increasing the inflation rate increases the apparent revenues and costs. Because all the projects have positive operating incomes, raising the inflation rate causes the cash flows to increase which in turn raises the IRR. The levelized cost increases as the inflation rate increases simply because the costs increase. NPV increases for the same reason.

Interest Rate

The interest rate affects the operating costs by changing the amount of interest paid on the loan. Increasing the interest rate increases operating costs which lowers the project's NPV and IRR, and increases the levelized cost.

Installed Cost

The effect of changing the installed cost of the project on NPV, IRR, and levelized cost is the same as that of the interest rate. Increasing the installed cost of the project increases the operating costs through increased interest payments and larger down payment which decreases NPV, IRR, and increases the levelized cost.

Effects on Financial Figures

Table 6.14 details the sensitivity analyses of the five factors on the net present value (NPV). In general, the greater the absolute magnitude to the NPV, the less sensitive it is to changes in a factor. For example, the California manure burning power plant has the greatest NPV when taken as an absolute value. It is the least sensitive of the five power plants to all factors. Conversely, the Texas lagoon digester has the smallest NPV and it is the most sensitive of the power plants to changes in factors. NPV is most sensitive to the installed cost of the project. Even the NPV of the California manure burning power plant changed ±16.6 by a ±10% change in installed cost. And this power plant was the least sensitive to installed cost of the five power plants.

Table 6.15 shows the IRR results from the sensitivity analysis. The effects of the discount rate are not included in Table 6.15 because the discount rate does no affect IRR as described above. Of the remaining factors, all but down payment have the same effect on IRR as on NPV; the greater the absolute magnitude of IRR, the less sensitive it is to changes in the factor. There appears to be no relationship between the magnitude of IRR and its sensitivity to change in the down payment. Like NPV, IRR is most sensitive to installed cost.

Table 6.14. Single Factor Sensitivity Analysis Net Present Value (NPV) for Manure Fueled Power Plants

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester	California Combustion Power Plant
Base Case NPV	$43,484	$14,167	-$8,857	$48,772	-$33,365,506
Discount Rate					
Low	$47,073 (8.2%)	$18,489 (30.5%)	-$7,258 (18.0%)	$54,277 (11.3%)	-$33,598,443 (-0.7%)
High	$40,109 (-7.8%)	$10,113 (-28.6%)	-$10,355 (-16.9%)	$43,626 (-10.6)	-$33,132,104 (0.7%)
Down Payment					
Low	$43,422 (-0.1%)	$13,768 (-2.8%)	-$9,162 (-3.4%)	$49,648 (1.8%)	-$33,387,347 (-0.1%)
High	$43,547 (0.1%)	$16,566 (2.8%)	-$8,546 (3.5%)	$47,877 (-1.8%)	-$33,343,201 (0.1%)
Inflation Rate					
Low	$40,205 (-7.5%)	$9,709 (-31.5%)	-$10,943 (-23.5%)	$44,269 (-9.2%)	-$33,895,067 (-1.6%)
High	$46,884 (7.7%)	$18,735 (32.2%)	-$6,721 (24.1%)	$53,399 (9.5%)	-$32,820,846 (1.6%)
Interest Rate					
Low	$46,805 (7.6%)	$20,505 (77.0%)	-$5,381 (39.2%)	$52,143 (6.9%)	-$31,742,947 (4.9%)
High	$40,100 (-7.8%)	$7,582 (-46.5%)	-$12,393 (-39.9%)	$45,333 (-7.0%)	-$35,017,450 (-5.0%)
Installed Cost					
Low	$55,999 (28.8%)	$36,229 (15.6%)	$3,514 (139.7%)	$62,622 (28.4%)	-$27,828,253 (16.6%)
High	$30,882 (-28.8%)	-$8,665 (-161.2%)	-$21,554 (-143.3%)	$34,922 (-28.4%)	-$38,902,759 (-16.6%)

Note:The left-hand figure in each column is the net present value due to 10% decrease (Low) or 10% increase (High) in factors on left. Figure in parentheses is percent change in net present value from base case caused by Low/High change in factor.

Table 6.15. **Single Factor Sensitivity Analysis Internal Rate of Return (IRR) for Manure Fueled Power Plants**

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester	California Combustion Power Plant
Base Case IRR21.51%	10.27%	3.96%	21.36%	-21.44%	
Down Payment					
Low	22.71% (5.6%)	10.44% (1.6%)	3.56% (-10.1%)	22.69% (6.2%)	-23.29% (-8.6%)
High	20.48% (-4.8%)	10.11% (-1.6%)	4.30% (8.6%)	20.22% (-5.4%)	-19.67% (8.3%)
Inflation Rate					
Low	20.73% (-3.6%)	9.43% (-8.2%)	2.98% (-24.7%)	20.46% (-4.2%)	-22.37% (-4.3%)
High	22.29% (3.6%)	11.09% (8.0%)	4.90% (23.7%)	22.26% (4.2%)	-20.50% (4.4%)
Interest Rate					
Low	22.51% (4.6%)	11.46% (11.6%)	5.36% (35.3%)	22.14% (3.6%)	-19.77% (7.8%)
High	20.49% (-4.7%)	9.02% (-12.2%)	2.51% (-36.6%)	20.56% (-3.7%)	-23.16% (-8.0%)
Installed Cost					
Low	26.85% (24.8%)	15.05% (46.5%)	9.03% (128.0%)	26.04% (21.9%)	-18.63% (13.1%)
High	16.86% (-21.6%)	6.02% (-41.4%)	-0.72% (-81.8%)	17.33% (-18.9%)	-23.84% (-11.2%)

Note:The left-hand figure in each column is the IRR due to 10% decrease (Low) or 10% increase (High) in factors on left. Figure in parentheses is percent change in IRR from base case caused by Low/High change in factor.

Table 6.16. Single Factor Sensitivity Analysis Levelized Cost ($/kWh) for Manure Fueled Power Plants

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester	California Combustion Power Plant
Base Case Levelized Cost	$0.1126	$0.0693	$0.0847	$0.0767	$0.0847
Discount Rate					
Low	$0.1163 (3.3%)	$0.0716 (3.3%)	$0.0875 (3.3%)	$0.0793 (3.4%)	$0.0875 (3.3%)
High	$0.1090 (-3.3%)	$0.0707 (-3.2%)	$0.0820 (-3.2%)	$0.0742 (-3.3%)	$0.0821 (-3.1%)
Down Payment					
Low	$0.1148 (1.9%)	$0.0707 (2.0%)	$0.0865 (2.1%)	$0.0779 (1.6%)	$0.0866 (2.2%)
High	$0.1103 (-2.1%)	$0.0679 (-2.0%)	$0.0828 (-2.9%)	$0.0754 (-1.7%)	$0.0828 (-2.2%)
Inflation Rate					
Low	$0.1119 (-0.6%)	$0.0688 (-0.7%)	$0.0842 (-0.6%)	$0.0759 (-1.0%)	$0.0843 (-0.5%)
High	$0.1132 (0.5%)	$0.0697 (0.6%)	$0.0851 (0.5%)	$0.0776 (1.2%)	$0.0851 (0.5%)
Interest Rate					
Low	$0.1110 (-1.4%)	$0.0683 (-1.4%)	$0.0833 (-1.6%)	$0.0760 (-0.9%)	$0.0832 (-1.8%)
High	$0.1141 (1.3%)	$0.0703 (1.4%)	$0.0861 (1.6%)	$0.0774 (0.9%)	$0.0863 (1.9%)
Installed Cost					
Low	$0.1043 (-7.4%)	$0.0644 (-7.1%)	$0.0779 (-8.0%)	$0.0724 (-5.6%)	$0.0780 (-7.9%)
High	$0.1208 (7.3%)	$0.0743 (7.2%)	$0.0916 (8.1%)	$0.0810 (5.6%)	$0.0914 (7.9%)

Note:The left-hand figure in each column is the levelized cost due to 10% decrease (Low) or 10% increase (High) in factors on left. Figure in parentheses is percent change in levelized cost from base case caused by Low/High change in factor.

Table 6.16 shows the levelized costs of the manure plants to be much less sensitive to changes on the five assumptions than the IRR. Like both NPV and IRR, levelized cost is most sensitive to the installed cost of the power plant, though not to as great a degree.

As can be seen from the tables, the installed cost has the greatest effect on the financial viability of the power plants. Its effect is most pronounced over the NPV.

Multiple Factor Analysis

It is unlikely that only one assumption would vary while others remained constant. It is more likely that a change in one assumption would occur simultaneously with a change in another assumption. Multiple factor analysis measures the effect these scenarios have on the models. There are three possible situations for each assumption in each scenario. Just as in the single factor analysis, each assumption may decrease, remain unchanged, or increase. With five assumptions the number of possible combinations is 3^5 or 243. This number can be reduced if we have some insight into the relationship between the assumptions.

Because of the economic relationships between the assumptions, it is likely that a change in one assumption would cause or, at least, coincide with a change in another assumption. For example, the correlation between interest rates and inflation between 1980 and 1990 was 0.92. This means that 92% of the time when one changed the other changed *in the same direction*. There is no causation taken into account as no causation should be inferred from correlation.

The discount rate is a function of both interest rates and inflation and, as a result, moves with them. From this, 216 combinations can be removed from the analysis as unlikely to occur. To further simplify the analysis we will not model the situation where the assumption remains unchanged. Therefore, there will be two basic scenarios. One is when the discount, inflation, and interest rates are all decreased and the other when they are increased. We will refer to these two scenarios as "Most Probable Scenario (Low)" and "Most Probable Scenario (High)". The down payment and installed cost will still vary because they are independent of the first three assumptions. Under each of the two main scenarios there are four combinations of outcomes.

Figures 3 and 4 each contain five columns: one listing the five assumptions included in the sensitivity analyses, and one for each of the four possible scenarios. As discussed earlier, we will assume that discount rate, interest rate, and inflation rate change together. Therefore, since Figure 3 shows the Low scenarios where discount rate, interest rate, and inflation rate are decreased, they are represented by minus signs in each column. Down payment and installed cost are assumed to be independent of the first three assumptions. Therefore, their change may be either positive or negative. For example, in the scenario Low-2, discount rate, interest rate, inflation rate, and down payment are all decreased by 10% while installed cost is increased by 10%. The resulting analysis shows what affect this combination of assumptions has on NPV, IRR, and levelized cost.

Figure 4 shows the High scenarios where discount rate, interest rate, and inflation rate are all increased by 10%. Again, down payment and installed cost are assumed independent of the first three. For example, in the scenario High-2, discount rate, interest rate, inflation rate, and installed cost are all increased by 10% while down payment is decreased by 10%.

For each of the five power plant sites, eight scenarios are analyzed: four low and four high. The five assumptions are increased or decreased by 10% from their base levels indicated in Tables 6.2 through 6.6.

Figure 6.3 Most Probable Scenarios (Low)

	Low -1	Low -2	Low -3	Low -4
Discount Rate	-10%	-10%	-10%	-10%
Interest Rate	-10%	-10%	-10%	-10%
Inflation Rate	-10%	-10%	-10%	-10%
Down Payment	-10%	-10%	+10%	+10%
Installed Cost	-10%	+10%	-10%	+10%

Figure 6.4 Most Probable Scenarios (High)

	High -1	High -2	High -3	High -4
Discount Rate	+10%	+10%	+10%	+10%
Interest Rate	+10%	+10%	+10%	+10%
Inflation Rate	+10%	+10%	+10%	+10%
Down Payment	-10%	-10%	+10%	+10%
Installed Cost	-10%	+10%	-10%	+10%

Tables 6.17, 6.18, and 6.19, like Tables 6.14 through 6.16, show the base case values for the three financial figures (NPV, IRR, and levelized cost) and the resulting value and percent change from the base case due to the high and low changes as diagrammed in Figures 3 and 4.

For example, in Table 6.17 which shows the effects of the sensitivity analysis on NPV. Looking at the California Covered Lagoon Digester one can see the base NPV was $48,772. Scenario Low-2, as described above, caused the NPV to decrease by 17.7% to $40,121. That is, the particular combination of changes in the five assumptions in scenario Low-2 resulted in a 17.7% decrease in the NPV of the California Covered Lagoon Digester.

Net Present Value (NPV)

Table 6.17 portrays the multiple sensitivity analysis on NPV. There are four scenarios (Low-1, Low-3, High-1, and High-3) which cause the NPVs for all five power plants to increase. In all four scenarios the installed cost is decreased. Regardless of the direction of change in the other four factors. The scenarios leading to the greatest apparent increase in NPV are Low-1 and Low-3. As can be seen in Figure 6.3, scenario Low-1 contains decreases in all five factors. The Low-3 scenario is the same except that the down payment is increased by 10%. Conversely, the four scenarios in which installed cost was increased all lead to decreases in NPV. In the single factor sensitivity analysis, installed cost was seen as the influential to NPV. Even with the combined effects of four other factors, installed cost is the most influential.

The Nebraska complete-mix power plant was the most sensitive to the installed cost. Its NPV was the lowest, in absolute terms, of the five power plants. The High-2 scenario caused a

212.5% decrease in NPV, turning a feasible project into a money loser. The High-2 scenario is the antithesis of the Low-3 scenario. In High-2 every factor is increased resulting in a NPV of -$15,934.

Internal Rate of Return (IRR)

Table 6.18 illustrates the effects of the scenarios on the IRR. The four scenarios with increases in IRR, Low-1, Low-3, High-1, and High-3, all include a decrease in installed costs. There is not a great difference between Low-1 and High-1 or Low-2 and High-2, etc., particularly for the California lagoon digester. The only difference between the low and high scenarios is the direction of change for the discount rate, interest rate, and inflation rate. As was seen previously in the single factor analysis, the discount rate has no effect on the IRR. The interest rate and inflation rate have opposite effects although the effect of the interest rate is slightly stronger than that of inflation.

The scenario causing the greatest improvement in the IRR, overall, was Low-1. For the one project with negative IRR (the Texas lagoon digester), Low-3 caused the greatest improvement. The difference between Low-1 and Low-3 is the change in the down payment. For the negative IRR project, the higher down payment increased IRR more. The combination of assumptions in Low-1 with the ten percent decreases in both down payment and installed cost actually cause an 19% decrease in the down payment.[47] Since the IRR is calculated using the down payment, a smaller down payment is equivalent to paying a smaller principal while receiving the same returns. This is why Low-1 increases the IRR. The combination of assumptions in Low-3 leads to a down payment almost equal to that of the base case.[48] Also, though the down payment in Low-3 is virtually the same as in the base case, the interest costs are lower as is the repayment to capital. Both these figures are unaffected by inflation and, in the case of the low scenarios, inflation decreases so the disparity between the interest payments and the other costs is lessened over time. This may explain why Low-3 is more favorable to the negative IRR project than Low-1.

As was noted above, IRR is most sensitive to changes in installed cost. The same appears to be true in the multiple factor analysis. Comparing scenarios 1 with 2, and 3 with 4, shows how increasing or decreasing the installed cost by ten percent alters the outcome greatly. As seen in Figures 3 and 4, the assumptions in the layers above scenarios 1 and 2 and above 3 and 4 are the same.

Levelized Cost

Looking at Table 6.19, the scenarios that would appear to cause a decrease in levelized costs would be those with a combination of high discount rate and low installed cost since they are the two most influential factors. The scenarios matching this combination are High-1 and High-3. Table 6.19 shows it is High-3 that causes the largest average decrease in levelized cost for the five projects. The order of percent change from the base case in the High-3 scenario from highest to lowest is the opposite of the high to low order of the IRR. The same is true for the order of percent change from the base case in scenario Low-2 which causes the greatest average increase in levelized cost.

Table 6.17. Multiple Factor Sensitivity Analysis Net Present Value (NPV) for Manure Fueled Power Plants

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester	California Combustion Power Plant
Base Case NPV	$43,484	$14,167	-$8,857	$48,772	$-33,365,506
Scenario					
Low-1	$59,440 (36.7%)	$41,702 (194.4%)	$6,124 (169.1%)	$67,574 (38.5%)	$-26,998,566 (19.1%)
Low-2	$34,573 (-20.5%)	-$2,501 (-117.6%)	-$18,743 (-111.6%)	$40,121 (-17.7%)	$-37,982,378 (-13.8%)
Low-3	$59,534 (36.9%)	$41,927 (195.9%)	$6,459 (172.9%)	$66,107 (35.5%)	$26,962,018 (19.2%)
Low-4	$34,687 (-20.2%)	-$1,510 (-110.6%)	-$18,059 (-104.0%)	$38,328 (-21.4%)	$37,937,708 (-13.7%)
High-1	$52,563 (20.9%)	$30,410 (114.6%)	$531 (106.0%)	$59,450 (21.9%)	$-28,646,449 (14.1%)
High-2	$26,960 (-38.0%)	-$15,934 (-212.5%)	-$25,023 (-182.5%)	$31,861 (-34.7%)	$-39,812,423 (-19.3%)
High-3	$52,697 (21.2%)	$31,022 (119.0%)	$1,052 (111.9%)	$57,734 (18.4%)	$-28,603,686 (14.3%)
High-4	$27,338 (-37.1%)	-$14,467 (-202.1%)	-$24,177 (-173.0%)	$29,764 (-39.0%)	$-39,760,157 (-19.2%)

Note:The left-hand figure in each column is the net present value due to the "Low" or "High" scenarios as diagramed in Figures 3 and 4. Figure in parentheses is percent change in levelized cost from base case caused by "Low"/"High" scenario.

Table 6.18. Multiple Factor Sensitivity Analysis Internal Rate of Return (IRR) for Manure Fueled Power Plants

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester	California Combustion Power Plant
Base Case IRR21.51%	10.27%	3.96%	21.36%	-21.44%	
Scenario					
Low-1	28.81% (33.9%)	16.06% (56.4%)	9.61% (142.7%)	27.66% (29.5%)	-19.57% (8.9%)
Low-2	18.05% (-16.1%)	6.37% (-38.0%)	-0.90% (-102.3%)	18.29% (-14.4%)	-24.85% (-15.9%)
Low-3	25.56% (18.8%)	14.72% (43.3%)	9.28% (134.3%)	24.37% (14.1%)	-16.41% (23.5%)
Low-4	16.36% (-23.9%)	6.53% (-36.4%)	0.43% (-89.1%)	16.35% (-23.4%)	-21.20% (1.1%)
High-1	28.19% (31.1%)	15.21% (48.1%)	8.56% (116.2%)	27.86% (30.4%)	-21.09% (1.6%)
High-2	17.22% (-19.9%)	5.27% (-48.7%)	-2.17% (-154.8%)	18.35% (-14.1%)	-26.72% (-24.6%)
High-3	25.30% (17.6%)	14.30% (39.2%)	8.66% (118.7%)	24.74% (15.8%)	-17.57% (18.1%)
High-4	15.97% (-25.7%)	5.85% (-43.0%)	-0.42% (-110.6%)	16.60% (-22.3%)	-22.69% (-5.8%)

Note:The left-hand figure in each column is the IRR due the "Low" or "High" scenarios as diagramed in Figures 3 and 4. Figure in parentheses is percent change in IRR from base case caused by "Low"/"High" scenario.

Table 6.19. Multiple Factor Sensitivity Analysis Levelized Cost ($/kWh) for Manure Fueled Power Plants

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester	California Combustion Power Plant
Base Case Levelized Cost	$0.1126	$0.0693	$0.0847	$0.0767	$0.0847
Scenario					
Low-1	$0.1077 (-4.3%)	$0.0664 (-4.2%)	$0.0804 (-5.1%)	$0.0744 (-3.0%)	$0.0804 (-5.1%)
Low-2	$0.1249 (10.9%)	$0.0767 (10.7%)	$0.0946 (11.7%)	$0.0835 (8.9%)	$0.0943 (11.3%)
Low-3	$0.1037 (-7.9%)	$0.0640 (-7.6%)	$0.0722 (-8.8%)	$0.0721 (-6.0%)	$0.0770 (-9.1%)
Low-4	$0.1199 (6.5%)	$0.0736 (6.2%)	$0.0906 (7.0%)	$0.0807 (5.2%)	$0.0902 (6.5%)
High-1	$0.1050 (-6.7%)	$0.0648 (-6.5%)	$0.0787 (-7.1%)	$0.0726 (-5.3%)	$0.0790 (-6.7%)
High-2	$0.1219 (8.3%)	$0.0751 (8.4%)	$0.0926 (9.3%)	$0.0814 (6.1%)	$0.0928 (9.6%)
High-3	$0.1009 (-10.4%)	$0.0623 (-10.1%)	$0.0754 (-11.0%)	$0.0703 (-8.3%)	$0.0756 (-10.7%)
High-4	$0.1168 (3.7%)	$0.0719 (3.7%)	$0.0886 (4.6%)	$0.0786 (2.5%)	$0.0885 (4.5%)

Note:The left-hand figure in each column is the levelized cost due to the "Low" or "High" scenarios as diagramed in Figures 3 and 4. Figure in parentheses is percent change in levelized cost from base case caused by "Low"/"High" scenario.

The High-1 scenario has the third greatest impact on decreasing costs. Low-3 has the second greatest impact despite the low discount rate. Here it would seem that in combination with the interest rate and inflation rate, the discount rate has less effect on levelized cost than the down payment. The decrease in percent change from High-3 to High-1 is greater than from High-1 to Low-3. This indicates that changing the down payment has more effect than changing the discount rate. It is interesting to note that the Low-1 scenario, which caused the greatest average improvement in IRR, caused the least improvement in levelized cost of the four scenarios with decreased levelized costs.

Even with the combined influence of the four other assumptions, the increase or decrease in installed cost still causes the sign to change on all three financial figures. Looking at the scenario pairs of Low-1/Low-2, Low-3/Low-4, etc., one can see the NPV and IRR rising and falling inversely to, and levelized cost rising and falling with the installed cost. Conversely, looking at pairs Low-1/Low-3, Low-2/Low-4, etc., shows that keeping installed cost unchanged and varying down payment does not cause the financial figures to change with down payment. Finally, comparing scenario pairs Low-1/High-1, Low-2/High-2, etc., shows that changing the discount, interest, and inflation rates together while keeping down payment and installed cost constant does not cause the three financial figures to rise or fall with them but adds to the trend initiated by installed cost. Looking at the percent change figures for every scenario on Tables 6.16 through 6.19 shows that only installed cost caused figures to rise and fall with it. The other assumptions only accentuated or muted the effect of the installed cost.

Other Factors

The five manure-fueled power plants modeled were most dependent on installed cost for their feasibility. One assumption that was not included in the sensitivity analysis was the price of electricity. This is not only the price one pays for electricity but what one sells it back to the utility for, if possible. As discussed above, the price of electricity can change yearly, seasonally, and even hourly. Because of this, the sensitivity analysis of the price of electricity would be mercurial. The majority of the revenues for the four digesters were made up of money saved through costs no longer incurred. For the California manure-burning power plant, the only source of revenue was from the sale of electricity produced to the local utility. Varying the price received for the sale of electricity from the power plant changed the NPV and IRR. NPV was more sensitive to the installed cost than to the price paid for electricity. The effect of a 10% increase in the price paid for electricity was an increase in NPV of 12.1%. A 10% decrease in the installed cost led to a 16.6% rise in NPV. Conversely, the effect of the price of electricity on the California manure burner's IRR was greater than that of installed cost. Increasing the price received by 10% caused the IRR to rise 21.3%. Decreasing the installed cost by 10% caused the IRR to rise 13.1%. This same analysis was performed on the South Dakota digester and found to have a lesser effect than installed cost. This is because, as discussed earlier, the digesters are less reliant on electricity sales for feasibility.

The Standard Offer 4 (SO4) rates discussed earlier that are currently being paid to many existing independent power plants are no longer available. The only rates currently available are SO1 rates which were used in the income statement analysis for the California direct combustion power plant. In late 1993 a new SO4 will become available to QF operators. It is impossible to tell exactly what the energy price will be because it will depend on the bids submitted to the utilities by the QF operators. Historically, with SO4 contracts the power plant operator had the choice of selecting a fixed price per kWh or a floating price or a combination of both. The price paid is the utility's avoided cost which was forecast to increase at a much greater rate than it has. Those operators that chose to sign a fixed rate contract are receiving a price that is much higher than the utility's current avoided cost.

Given the assumptions used in the income statement, the energy prices received for the manure burning power plant's electricity must be very high to make it feasible. Break-even analysis using increases in the prices paid to the producer for electricity shows that both the energy and demand rate would have to increase 95% before the manure burning plant's NPV became positive.

The installed cost of the digester facilities was seen to be the single most influential assumption of those analyzed. The installed cost is based on the generating capacity of the power plant. As demonstrated earlier, the capacity is based on the number of animals at the farm and the amount of manure collected. The "capacity reserve adder" adds 20% to the basic kW capacity figure calculation. The purpose of the adder was to assure sufficient power generating ability if there should be an increase in either the number of animals or an increase in manure collection efficiency. Adding the extra capacity also raises the cost of installing the power plant.

Because the installed cost is so important to the financial feasibility of the project, the income statement analyses were performed again, this time without the capacity reserve adder. Table 6.20 shows the resulting capacities, installed costs, and financial figures when the capacity is not increased by 20%. The installed costs of all the digesters, except Nebraska, do not decrease as much as the capacity. The Nebraska digester's installed cost is based on the cost of a similarly sized digester. Economies of scale reduce the cost at a lower rate than the reduction in capacity. Without the reserve adder all the digester projects have IRRs greater than zero. The California manure-burning power plant is not included because its capacity is not calculated using the reserve adder.

Table 6.20. Summary of Assumptions and Income Statements for Manure Digesters Without 20% Capacity Reserve Adder

	South Dakota Plug Flow Digester	Nebraska Complete-Mix Digester	Texas Covered Lagoon Digester	California Covered Lagoon Digester
Capacity (kW)	29	84	34	68
Installed Cost	$132,287	$207,715	$115,240	$177,616
Net Present Value	$53,818	$43,450	$3,654	$65,574
Internal Rate of Return	25.94%	17.44%	9.09%	27.26%
Levelized Cost ($/kWh)	$0.1059	$0.0605	$0.0780	$0.0716

The number of animals at the site of a manure fueled power plant can also have an effect on the feasibility of a project. To demonstrate, the number of cows at the Texas covered lagoon digester was increased so that its herd became the same size as the assumed size of the California covered lagoon digester herd. Because both facilities use the same type of digester and their capacity calculation and electricity production calculation assumptions are the same, the resulting capacities and installed costs were identical. The electricity price assumptions were left alone as were the O&M costs.

Because the differential between the assumed buying and selling prices of electricity were greater in California than in Texas, the Texas digester still did not perform as well financially as the California digester. However, compared to the smaller Texas herd, the large Texas herd increased the net present value by more than thirteen times to $2,952, increased the IRR to 8.26%, and decreased the levelized cost by over 18% to $0.0693/kWh. Most of the difference caused by doubling the size of the herd was the result of doubling the capacity without doubling the installed cost. The installed cost increased by only 57% due to economies of scale in the installed cost which was previously shown graphically in Figures 3 and 4.

6.4 Economic Analysis Conclusions

Pro forma income statements were calculated and analyzed to model the feasibility of five separate manure fueled power plants. Four of the power plants modeled were anaerobic manure digesters producing flammable biogas to be burned in internal combustion engines which then turned electrical generators. The four digesters, located in South Dakota, Nebraska, Texas, and California were designed to produce electricity in sufficient quantities as to make the farm or dairy electrically self-sufficient. The fifth power plant modeled was a large steam power plant which burned the manure directly to produce steam which spun steam-turbines and then electrical generators. This plant, located in California, was designed only to produce electricity for resale to a local electric utility. The assumptions used in the income statement models were based on prior research and the data available that best fit the technology being modeled and the location of the facility.

The pro forma income statements were calculated for a ten year period. Financial statistics included in the analysis were net present value (NPV), internal rate of return (IRR), and levelized cost. Also taken into account in the income statements were expenses related to borrowing for capital. Funding for the projects was assumed to be from U.S. Small Business Administration (SBA) loans which offer low interest rates and are guaranteed for up to $750,000.

The results of the analysis concluded that the large direct combustion power plant in California was not feasible based on the rates the electricity would sell for. The utility's avoided cost, upon which is based the price the utility offers for energy it buys, is too low for the power plant to pay for itself. Given the model's assumptions, the price paid for the power plant's electricity would have to rise 95% before the NPV became positive. If the impending SO4 rates are at least that much higher than current SO1 rates the power plant would be feasible.

Three of the four digester power plants would be feasible, based on their positive NPVs, with the given assumptions. The only digester judged not feasible was the covered lagoon digester in Texas. However, its NPV of -$8,857 and IRR of 3.96% were not so low that they could not be improved. In the sensitivity analysis of the Texas power plant, two assumptions, the interest rate and installed cost, proved to have the most influence on NPV and IRR. The other three digesters modeled were the South Dakota plug flow digester, Texas covered lagoon digester, and California covered lagoon digester. All three were judged to be feasible given the assumptions. All three had positive NPVs and IRRs of at least 10.3%.

The assumption with the most influence on the financial strength of the digesters was the installed cost of the power plant. When the effects of varying the assumptions were combined, installed cost had more influence than the other assumptions. For the direct combustion power plant the price paid by the utility for the electricity produced was most significant. The price of electricity did not have the same influence on the digesters because their largest source of revenue was the savings created by no longer having to buy electricity.

Using the assumptions given, the South Dakota plug flow digester, the Texas covered lagoon digester, and the California covered lagoon digester are all financially feasible. The Nebraska complete-mix digester and the California manure burning power plant are not feasible. With a lower interest rate or a decrease in the assumed installed cost the Nebraska digester could easily be feasible. The California manure burning power plant needs to be able to sell its electricity for almost 100% more than the going rate in California to be feasible.