An Assessment of the Potential for Electricity Generation in Indiana from Biogas Resources

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Executive Summary

With continuing attention to the use of renewable energy, particularly in the electric power sector, an assessment of the potential for expansion of the use of waste biomass for electricity generation provides a basis for evaluating policies designed to encourage this energy source. This report estimates the potential expansion of electricity generation in the state of Indiana from the combustion of biogas produced from three alternative sources of waste biomass – manure from livestock farms, sewage from wastewater treatment plants, and municipal solid waste from landfills. The impact of alternative policies such as investment tax credits, production tax credits, and feed-in tariffs is also assessed.

Generation of electricity from biogas on livestock farms is only economically viable under restrictive circumstances. The livestock operation must be large enough to be able to make the adoption of the system economical, and the existing manure handling processes and facilities must be compatible with the requirements of the biogas production technology without major new investments. Other barriers include financing and pricing of electricity produced in excess of the needs of the farm.

Generation of electricity from biogas from waste water treatment plants (WWTPs) can be economically viable provided that the size of the treatment facility (measured in millions of gallons per day or MGD) of influent) is sufficient. The critical level is in the 4-10 MGD range with the lower end of the range requiring supplementation of the influent with food service facility wastes, such as fats, oil, grease, food waste, and process waste from beverage industries. Operating a WWTP is electricity intensive, and self-generation of electricity from biogas is virtually never sufficient to allow sales to the grid. Thus, the value of the electricity produced by a WWTP is in terms of the reduction in purchases from the electric utility. However, the utility serving a WWTP plant may apply a different, standby electricity rate for a WWTP that self-generates.

Generation of electricity from biogas from landfills is fairly common with 22 energy projects currently operating in Indiana. This is in part due to EPA requirements that landfills that exceed size criteria for amount of material in the land fill and for the emission of non-methane organic compounds are required to have landfill gas collection systems. Due to this requirement, only the cost of additional equipment to allow generation of the electricity and its delivery to the grid needs to be covered by revenue from electricity sales.

Under current economic conditions, additional biogas-fired generating capacity of about 37 MW appears to be technically and economically feasible. It should be noted that this result is highly sensitive to the capital costs assumed for developing biogas generation, dropping by nearly one quarter when capital costs are increased 10 percent, and dropping by over 60 percent when capital costs are increased by 20 percent. This sensitivity is decreased with the introduction of any type of incentives, and larger incentives make the results more robust to increases in capital costs.

Analysis of policies designed to increase investment in biogas-fired generating capacity, including investment credits, production credits, and feed-in tariffs, indicates that the response is small – on the order of 3 MW of capacity – unless the incentives are quite large. A larger response would require an investment credit of over 30 percent, a production credit of over 5 cents per kWh, or a feed in tariff of about 13 cents per kWh. Because of differences in how the electricity is valued (i.e. whether it is all or in part sold to the grid or is used to offset in-house electricity needs), different facilities will respond to these incentives differently.

Analysis of the costs versus benefits of the alternative policy scenarios compares the total cost of the alternative incentive programs, which range from $10M to over $108M. The most easily quantified benefit is displaced emissions of CO_2, which range from 3.03 million metric tons (no incentives) to 3.34 million metric tons for the policies examined, indicating that the emissions reductions associated with the incentives are modest. When the offset emissions are valued at $13 per metric ton, the value of the emissions reductions associated with the incentives are small – in the range of $2.9M to $4.0M – far less than the costs of the incentives. However, other benefits such as odor reduction are not taken into account because they are difficult to value. There may also be unintended consequences that are not taken into account. For example, subsidizing adoption of electricity generation from biomass may slow the rate of technical progress for that technology and may divert efforts for development and adoption of other renewable energy technologies.

In sum, it appears that the prospects for expansion of electricity generation from biogas in the state of Indiana are limited. Incentive programs either based on investment cost sharing or through subsidizing revenues from grid sales appear to be costly, with the costs exceeding the most easily valued benefits. Nonetheless as the need to develop renewable electricity generation capacity increases, the information available in this report will provide a basis for considering biogas versus alternative renewable energy technologies.

Table of Contents

1. Overview

With continuing attention to the use of renewable energy, particularly in the electric power sector, an assessment of the potential for expansion of the use of waste biomass for electricity generation provides a basis for evaluating policies designed to encourage this energy source. This report estimates the potential expansion of electricity generation in the state of Indiana from the combustion of biogas produced from three alternative sources of waste biomass – manure from livestock farms, sewage from wastewater treatment plants, and municipal solid waste from landfills. The impact of alternative policies such as investment tax credits, production tax credits, and feed-in tariffs is also assessed.

1.1 Introduction

Anaerobic digestion is a common part of organic waste management systems. It occurs when microorganisms break down organic material in an environment free of oxygen. The process produces biogas, which is made up of 50 to 70 percent methane, which can be used as a source of energy. Anaerobic digestion is used in concentrated animal feeding operations (CAFOs) as a way to treat livestock manure, in wastewater treatment plants (WWTPs) to treat sewage, and it occurs in all municipal solid waste (MSW) landfills as the organic waste breaks down. Biogas can be treated and used to generate electricity, used as transportation fuel, used as fuel for space or water heating, or upgraded to natural gas pipeline quality and delivered to the pipeline. Feedstock sources for its production include various organic wastes such as livestock manure, food processing byproducts, food waste, sewage, green waste (i.e. garden waste such as grass clippings or hedge trimmings), fats, oils and grease.

Numerous CAFOs, WWTPs and MSW landfills in the United States, including some in Indiana, are currently producing biogas. While some facilities choose to flare the biogas, others use the biogas for on-site electricity generation and/or to meet heating needs. In addition to being a renewable source of energy, the production and use of biogas has other benefits. Methane (CH_4), the biggest component of biogas, is considered to be a powerful greenhouse gas that has a global warming potential 21 times that of CO_2 (Intergovernmental Panel on Climate Change, 2007). Unless otherwise captured and burned, methane produced at these facilities is released into the atmosphere. Additionally electricity generated using biogas displaces generation at bigger power plants. These may use other fuels such as coal which emits large quantities of greenhouse gases and several different types of pollutants including mercury and sulfur dioxide. Thus, the use of biogas for electricity generation could contribute to a reduction of the emissions of greenhouse gases and air pollutants.

There are many facilities with enough feedstock to generate electricity from biogas in the state of Indiana. Some of these are so small that electricity generation would likely not be profitable.

However many larger facilities are candidates for electricity generation projects, including 32 dairy farms with over 500 dairy cows, 694 hog operations with over 1,000 hogs, 26 WWTPs with a flow greater than 5 million gallons per day (MGD), and 14 landfills. Despite the large number of opportunities for electricity generation from biogas, only projects in MSW landfills have been developed extensively (see Table 1-1). Estimates of the electricity generation potential from biogas for the state of Indiana have not been very accurate. Many of these estimates have been part of national aggregates and have only taken into account the availability of feedstock sources, ignoring factors such as technical and economic feasibility. Assessing the effectiveness of policies that encourage the production and use of this renewable resource requires a better understanding of its availability and the economics of its production. The goal of this report is to estimate the electricity generation potential from biogas for Indiana and explore which policies would be effective in incentivizing biogas electricity projects.

This report first provides background on the anaerobic digestion process in general and as it applies to the specific facilities being considered. The background section also discusses the technical and economic constraints for each type of facility. The procedures section briefly describes the method that was used to evaluate biogas electricity projects and provides a list of the facilities that were identified as suitable for the installation of a biogas electricity project. The results section summarizes how many of these projects can be expected to be profitable under the current economic conditions and under different policy scenarios. The results section also discusses possible consequences of different policy alternatives.

Facility Name	Type of Facility	City	County	MW Capacity
Bio Town Ag, Inc.	CAFO	Reynolds	White	3.30
Bos Dairy	CAFO	Fair Oaks	Jasper	1.05
Culver Duck Farm	CAFO	Middlebury	Elkhart	1.20
Fair Oaks Dairy - Digester 1	CAFO	Fair Oaks	Jasper	0.70
Fair Oaks Dairy - Digester 2	CAFO	Fair Oaks	Jasper	1.05
Herrema Dairy	CAFO	Fair Oaks	Jasper	0.80
Hidden View	CAFO	Rensselaer	Jasper	0.95
Evansville Westside WWTP	WWTP	Evansville	Vanderburgh	N/A
Jasper WWU	WWTP	Jasper	Dubois	0.07
West Lafayette WWTP	WWTP	West Lafayette	Tippecanoe	0.13
Clark-Floyd LF	MSW Landfill	Borden	Clark	2.14
Clark-Floyd LF	MSW Landfill	Borden	Clark	1.40
Deercroft RDF	MSW Landfill	Michigan City	La Porte	3.20
Deercroft RDF	MSW Landfill	Michigan City	La Porte	3.20
Earthmovers LF	MSW Landfill	Elkhart	Elkhart	4.00
Jay County LF	MSW Landfill	Portland	Jay	3.20
Jay County LF	MSW Landfill	Portland	Jay	2.40
Liberty LF	MSW Landfill	Monticello	White	3.20
Liberty LF	MSW Landfill	Monticello	White	3.20
Munster LF	MSW Landfill	Munster	Lake	0.13
Oak Ridge RDF	MSW Landfill	Logansport	Cass	3.20
Prairie View LF	MSW Landfill	Bremen	St. Joseph	3.20
Prairie View LF	MSW Landfill	Bremen	St. Joseph	3.20
South Side LF	MSW Landfill	Indianapolis	Marion	4.00
Twin Bridges RDF	MSW Landfill	Danville	Hendricks	3.20
Twin Bridges RDF	MSW Landfill	Danville	Hendricks	3.20
Twin Bridges RDF	MSW Landfill	Danville	Hendricks	3.20
Twin Bridges RDF	MSW Landfill	Danville	Hendricks	3.20
Veolia ES Blackfoot LF, Inc.	MSW Landfill	Winslow	Pike	3.20
Wheeler RDF	MSW Landfill	Hobart	La Porte	2.40
Wheeler RDF	MSW Landfill	Hobart	La Porte	1.60
Wheeler RDF	MSW Landfill	Hobart	La Porte	0.80
Total				69.72

Table 1-1: Biogas Electricity Projects in Indiana

2. Background

2.1 The Anaerobic Digestion Process

Anaerobic digestion is a biological process in which microorganisms break down organic material in the absence of oxygen. It occurs naturally when manure is stored in liquid manure systems or when organic wastes are buried in landfills, or it can be engineered as part of a waste management system in confined animal feeding operations (CAFOs) and wastewater treatment plants (WWTPs). The process can be divided into three stages that are performed by three different groups of microorganisms (see Figure 2-1). The first stage is called hydrolysis. During this stage cellulose, lipids, proteins, and other complex organic compounds are liquefied by the bacteria and converted into soluble compounds. The second stage is known as the volatile acid fermentation stage. During this stage the soluble organic matter produced in the hydrolysis stage is converted into volatile organic acids through the processes of acidogenesis and acetogenesis. During acidogenesis organic molecules are converted to fatty acids, and during acetogenesis fatty acids are converted to acetic acid, carbon dioxide, and hydrogen. The bacteria that perform the first two steps are commonly known as acidogenic bacteria. The third stage is the biogas production stage. During this step methanogenic bacteria convert the acetic acid into methane, carbon dioxide, and small amounts of water vapor, hydrogen sulfide and ammonia (U.S. EPA, 2006). Maintaining methane production from an anaerobic digester is sensitive, and temperature and pH must be kept with a narrow range.

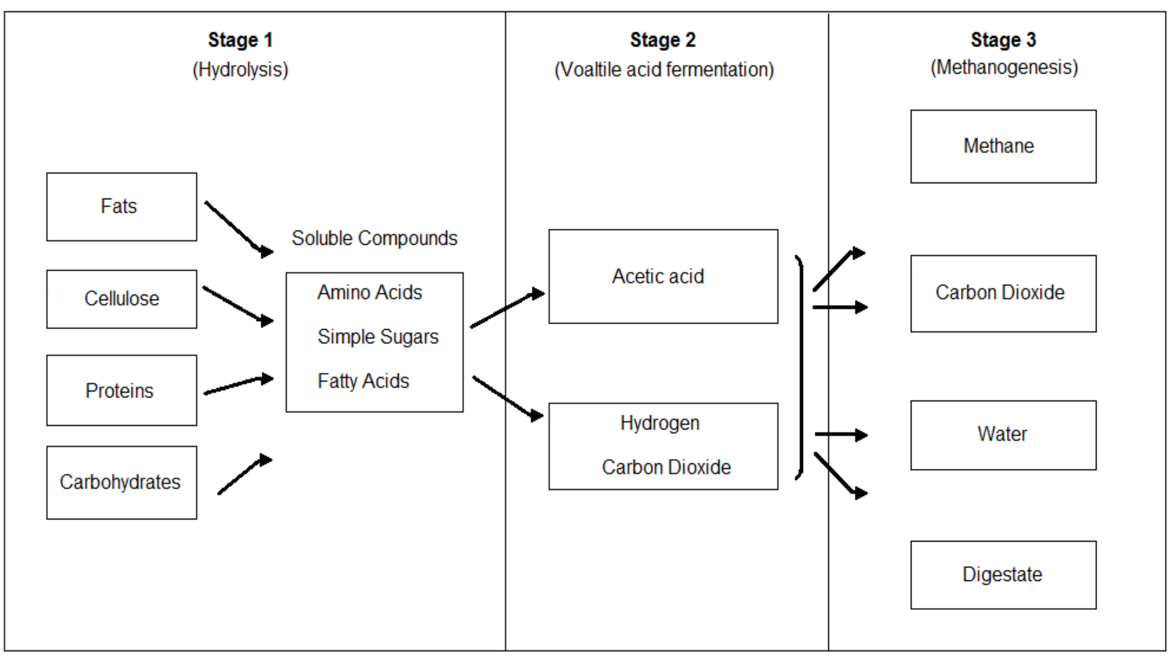

Figure 2-1: The Anaerobic Digestion Process

The composition of the biogas will vary depending on the facility (see Table 2.1). The efficiency of the process will be influenced by the temperature, as higher temperatures are more suitable for bacterial growth, and the retention time, which is the time that the process is allowed to take place. Not all of the soluble organic matter and organic acids will be converted into biogas; some will be unprocessed and become part of the effluent. The rest of the effluent will be a stabilized waste solution, meaning it will have a lower biological activity of organic matter (which can attract disease carrying organisms), a reduced mass of organic solids, and a reduction in the concentration of pathogenic bacteria (Parry, et al., 2004).

Facility	CH_4 (%)	CO_2 (%)	O_2 (%)	N_2 (%)	H_2S (parts per million (ppm))
Landfill	47-57	37-41	< 1	< 1 -17	36-115
WWTP digester	61-65	36-38	< 1	< 2	b.d.*
CAFO digester	55-58	37-38	< 1	< 1-2	32-169

Table 2-1: Biogas Composition from Different Production Facilities
* b.d.—below detection limit 0.1 ppm
Source: Rasi, Veijanen, and Rintala, 2007.

2.2 Confined Animal Feeding Operations

Over the past several decades U.S. dairy and hog operations have undergone a gradual structural change driven by specialization and greater size, resulting in fewer farms and with larger livestock herds (see Table 2-2). This consolidation has meant that an increasing volume of manure is being produced at fewer, larger locations. This creates a challenge for traditional manure management practices involving land application as higher manure-to-cropland ratios and higher application rates increase the risk of contamination of ground and surface water with manure nutrients and pathogens. Additionally, conflicts with nearby communities have increased over odor and air quality (Key and McBride, 2011; Macdonald, et al., 2007). Anaerobic digestion as part of their manure handling system helps to offset some of these problems because it reduces the risk of environmental contamination, reduces offensive odors, and generates renewable energy.

Year	1987	1997	2007
Number of hog farms	238,619	109,754	74,789
Hog farms with herd size of 5,000 or more	1,630	1,851	7,991
Number of dairy farms	202,068	116,874	69,890
Dairy farms with herd size of 500 or more	1,268	2,257	4,866

Table 2-2: U.S. Dairy and Hog Industry Trend for 1987-2007
Source: Census of Agriculture 1987, 1997, 2007.

Technical and economic factors limit the feasibility of the adoption of anaerobic digestion (AD) systems on farms. One important technical factor is related to the manure handling and storage system on the farm (Gloy, 2011). AD systems are designed to handle manure in a semiliquid form that has at least 85 percent moisture content. Manure handling systems that handle manure in a semiliquid form include the flush system, pit recharge, pull plug, and deep-pit system at hog farms and the scrape system and flush system at dairy farms. However the deep-pit system, which is the most common manure handling system at hog farms, is unsuitable for AD systems for two reasons. Because the manure is not removed frequently enough, substantial amounts of methane are produced in the storage pit itself. Also they do not have additional storage where digested manure could be placed. Adding a storage lagoon would significantly increase capital costs as an additional manure storage facility would have to be built. Another limitation is created if inorganic materials such as sand, gravel and dirt are added to the manure as it is collected. This would happen at farms that use sand as bedding or use a dry system. These inorganic materials tend to settle out of suspension and become deposited in the digester. Once enough of this material builds up inside the digester, it has to be opened and cleaned. This causes the operator to incur a substantial cost and digester downtime. These limitations mean that, without costly additional modifications to the manure management system, only hog farms using the flush system, pit recharge, or pull plug system and dairy farms using the scrape system are compatible with AD adoption.

There are several designs of anaerobic digester available; the most appropriate for a particular farm will depend on their manure handling system and the climate where the farm is located. Only the most commonly used designs are addressed in this report. There are 3 main categories of anaerobic digester designs: the covered anaerobic lagoon digester, the complete mix digester, and the plug flow digester.

The covered anaerobic lagoon consists of a pond-like earthen basin that is sealed with a flexible cover that captures the biogas (see Figure 2-2). Anaerobic lagoons are used to treat manure with less than 3 percent solids, therefore they are best suited for systems that handle manure in a liquid form. Because they are unheated and operate at ambient temperature, for energy production they are only viable below the 40^{th} parallel (Natural Resource Conservation Service (NRCS), 2009). This is because warmer ambient temperatures are required to produce enough biogas to support an electricity generator. For this reason this design is not suitable for the state of Indiana (see Figure 2-3).

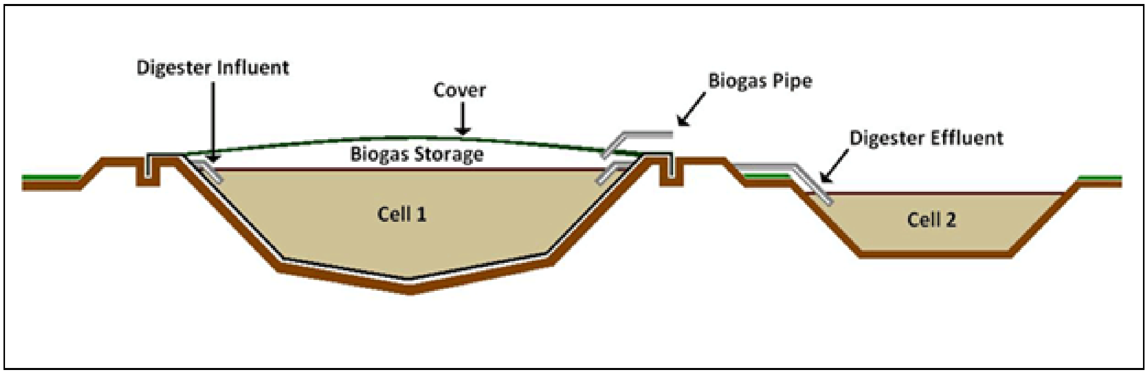

Figure 2-2: Anaerobic Lagoon Digester
Source: EPA AgSTAR, 2012.

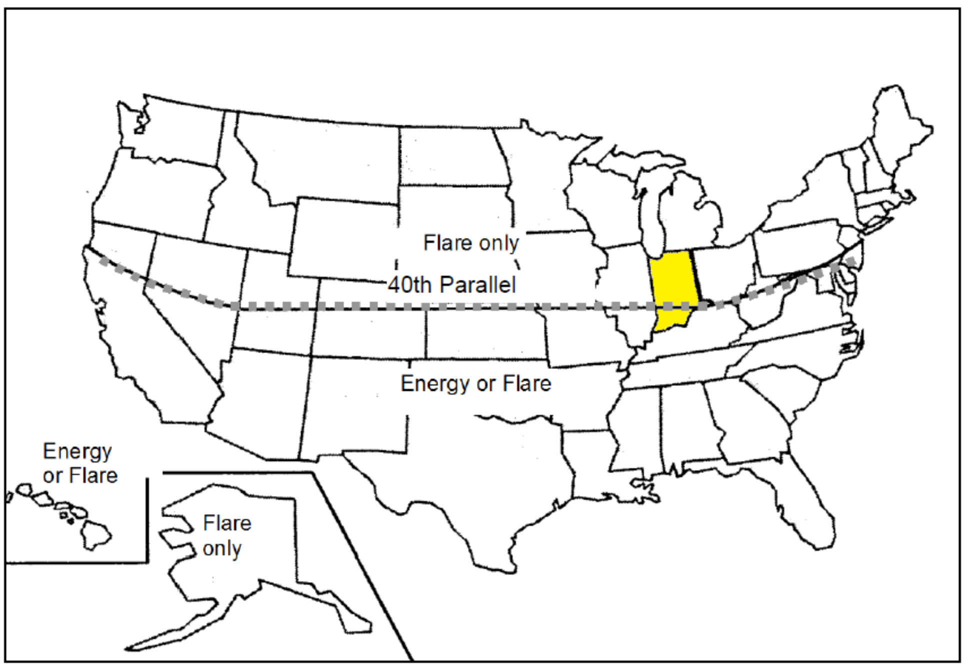

Figure 2-3: Anaerobic Digester Lagoon Geographic Range
Source: U.S. NRCS, 2009.

A complete mix digester (see Figure 2-4) is an enclosed insulated tank, made of reinforced concrete, steel or fiberglass. Heating coils inside the tank circulate hot water in order to keep the operational temperature warm enough to maintain active AD (NRCS, 2009). The contents are mixed with a mechanical, hydraulic, or gas mixing system. As the influent enters the digester, it displaces volume, causing an equal amount to flow out. The system uses a gas-tight cover (that can be flexible or rigid) to trap the biogas. The complete mix digester is best suited to process liquid manure that has 3-12 percent total solids.

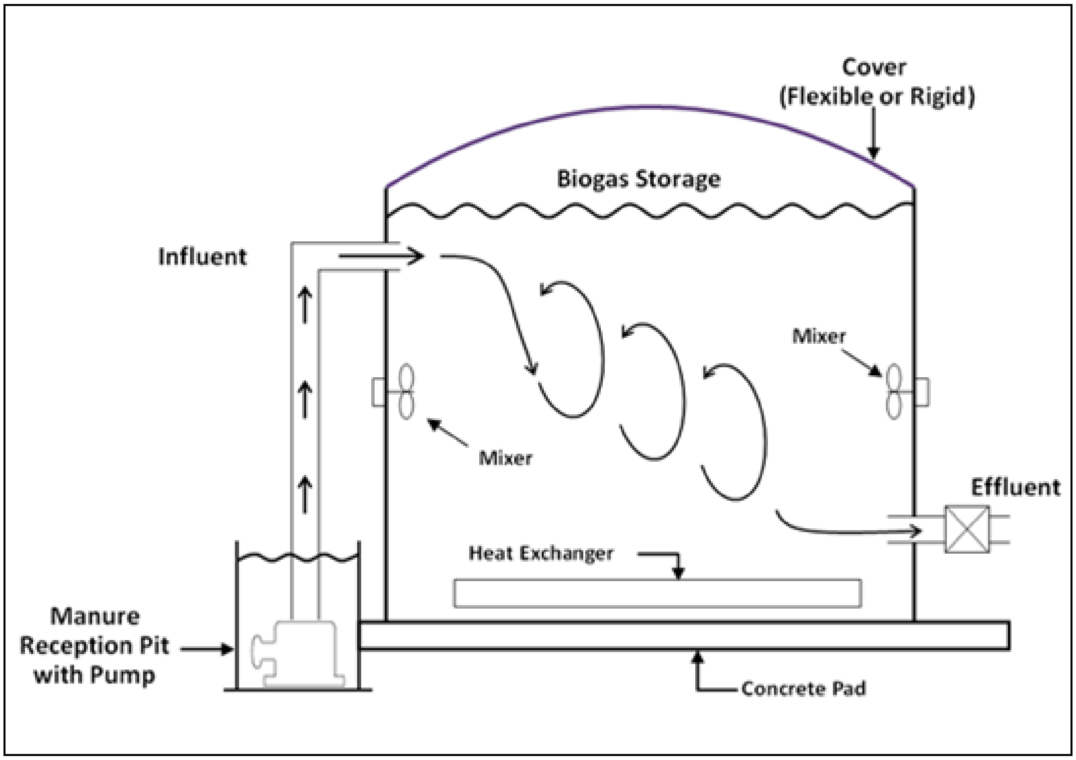

Figure 2-4: Complete Mix Digester
Source: EPA AgSTAR, 2012.

A plug flow digester (see Figure 2-5) is a long and narrow rectangular concrete tank with a flexible or rigid cover to capture the biogas. The tank is heated, insulated, and built partially or fully below the ground in order to limit heating requirements. The tank operates at the mesophilic range[1] and is best suited for dairy manure from a scraped system with 11-14 percent total solids. The manure does not mix as it makes its way longitudinally through the digester. As new manure is added, it displaces an equal volume out, hence the name plug-flow, because the manure moves as a plug through the digester without mixing.

[1] The mesophilic range is between 20°C and 40°C, or between 68°F and 104°F.

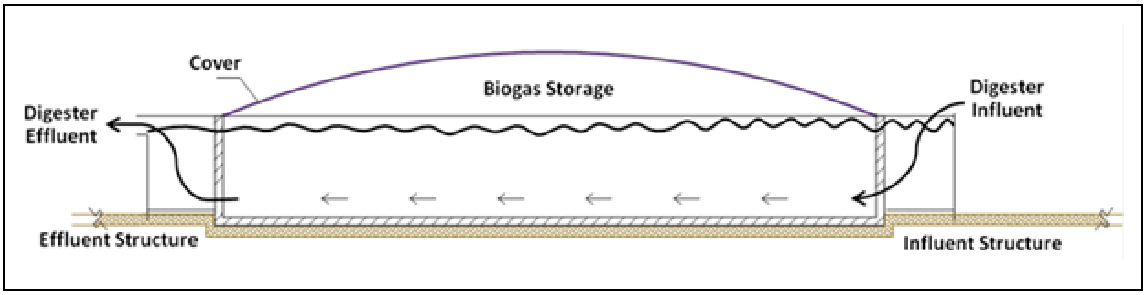

Figure 2-5: Plug flow digester
Source: EPA AgSTAR, 2012.

Both the complete mix digester and the plug flow digester have a heating requirement in order to be able to produce enough biogas to run the electricity generation equipment. In order to meet the heating requirement, AD systems that use either a complete mix or plug flow digester use combined heat and power (CHP) systems. A CHP system is not a single technology but rather is composed of several technologies that allow for the generation of electricity and the recovery of waste heat. The waste heat in this case is used to heat the digester.

There are also economic factors that impact the viability of an AD system at a livestock operation. AD systems exhibit economies of scale related to both capital and maintenance costs. AD systems represent a large capital expenditure of which the biggest component is the construction costs for the digester, storage facility, and buildings. Due to economies of scale, these tend to decline on a per animal unit basis. The operating and maintenance costs of the electricity generation equipment decline on a per kWh basis. There are also fixed costs associated with the selling of electricity that do not vary much with farm size or generation capacity (Key and Sneeringer, 2011). The economies of scale combined with the fixed cost of connecting the generator to the grid make the average total cost of generating electricity lower on larger systems, making AD system adoption more attractive for larger farms.

Apart from the economies of scale there are several other factors that affect the economics of a project regardless of the size. AD systems represent a large capital expenditure, and it is likely that part of the costs will have to be financed. Gloy and Dressler (2010) identified financing as a significant barrier for AD system adoption. The terms and requirements to sell the generated electricity are also important. A producer must meet interconnection requirements of the specific utility including procedures and equipment. Depending on the utility, specific farm location, and power output the interconnection requirements may represent a significant cost.

The operator must also negotiate a power purchase agreement to establish the terms of sale of the surplus electricity. A long-term contract, usually 15 years, is favored in order to ensure the revenue for the project. There are 3 main price levels at which utilities will usually purchase electricity: avoided cost, feed-in tariff, and net metering. Avoided cost is a rate that is approximately one-third to one-fourth of the retail price of electricity and represents the cost that the utility avoids by accepting the generation supplied by the farm – this is primarily the fuel cost of the marginal generating unit (EPA, 2004). A feed-in tariff is a rate that is above the retail price of electricity that may be paid to renewable sources of energy in order to encourage their production. Net metering, which is more suitable for smaller producers (<1 MW), is where the electricity delivered to the grid is priced at the retail rate during the applicable billing period – effectively allowing the producer to "run their meter backwards." From the farm's perspective the value of generation can be divided into 2 separate parts, the avoided cost of electricity purchases (for generation up to the level that is consumed on the farm) and the revenue from the sale of electricity to the utility (for generation exceeding the needs of the farm). Higher electricity price and higher on farm electricity consumption make the adoption of an AD system more viable because they increase the value of avoided electricity purchases. The revenue from electricity sales to the grid depend on the price negotiated by the producer.

Another potential source of revenue is the solid material from the digester effluent which can be separated and used as a crop fertilizer or as livestock bedding. Operators can enhance the economics of an AD system by co-digesting other organic wastes such as wastes from food processing plants, ethanol plants, and produce retailers. Co-digestion increases revenue by increasing biogas production, which therefore increases electricity production, and by receiving tipping fees, which are payments received for accepting the organic wastes. Finally, waste heat from the generators can be used for space heating in the farm buildings, offsetting heating cost.

2.3 Wastewater Treatment Plants

WWTPs are owned by public utilities and are used to treat wastewater and sewage with the purpose of producing an environmentally safe effluent that can be discharged into a body of water. The process of treating the wastewater involves several steps to physically, biologically and chemically remove the solids and pollutants present in the influent (see Figure 2-6). The organic solids removed during the different steps are combined to form a biosolids sludge that must be further processed before final disposal. One of the ways in which the sludge can be treated is using anaerobic digestion.

Wastewater treatment is very energy intensive as it requires the use of large pumps, drives, motors, and other equipment on a 24 hour a day basis. Electricity purchases at WWTPs often account for more than 25 percent of total operating cost (Wiser, Shettler, and Willis, 2010). For this reason WWTPs are among the largest energy users in a community (U.S. EPA, 2008). The use of biogas from anaerobic digestion to generate electricity represents an opportunity for public utilities to reduce their operational costs by offsetting electricity purchases. This would benefit rate and tax payers and allow utilities to run a more sustainable operation.

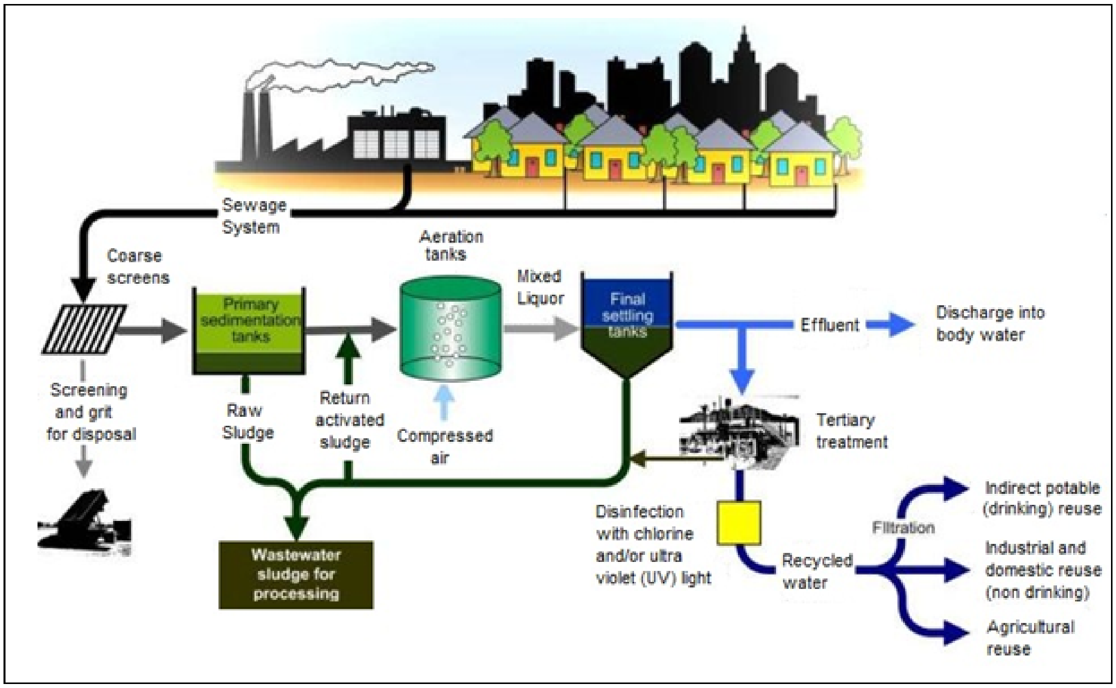

Figure 2-6: Wastewater Treatment Process
Source: Australian Water Association, 2009

Anaerobic digestion is commonly used in WWTPs for treating biosolids sludge. It stabilizes the organic matter in the sludge, reduces pathogens and odors, and reduces the total sludge quantity (U.S. EPA, 2006). The ideal temperature for operating a WWTP's anaerobic digester is at a level that requires heating. For this reason a CHP system where the waste heat is used to heat the digester has been the preferred technology for implementing energy projects at WWTPs.

The economic considerations of installing a CHP system at a WWTP are different than those of an AD system at a livestock operation. Because WWTPs consume so much electricity they will use all of the electricity that they generate. In the U.S. none of the WWTPs operating a CHP system have been able to achieve energy self-sufficiency; at best they offset 40 percent of their electricity purchases (Wiser, Shettler, and Willis, 2010). The decision of a WWTP to invest in a CHP system hinges on whether the savings from reduced electricity purchases are greater than the additional capital and operating costs. Ideally the lower electricity demand would translate proportionally into a lower electricity bill. However, this may not be the case as utilities apply standby rates to customers who generate their own electricity. These standby rates, which are determined by the specific utility, are for the provision of electricity for the portion of usage that is not generated by the CHP system and for periods when there may be scheduled or unscheduled outages. Because standby rates could potentially be high enough to prevent the operator from realizing cost savings large enough to cover the additional expenses of a CHP system they are an important determinant of the decision to invest in a CHP system (U.S. EPA, 2009).

Biogas production at WWTPs (and therefore electricity generation) is related to the daily flow of influent in million gallons per day (MGD). Historically, because of economies of scale, CHP systems have been thought to be economically viable only at WWTPs with influent rates greater than 10 MGD (Wiser, Shettler, and Willis, 2010). Because total capital costs do not scale proportionally with the size of the operation, larger operations are more likely to realize savings large enough to justify the investment. However, in recent times this convention has been challenged as smaller operations, in the range of 4-5 MGD, are successfully operating CHP systems. This is due to the co-digestion of fats, oil, grease, food waste and process waste from beverage industries which increases biogas production and therefore savings from reduced electricity purchases (Wiser, Shettler, and Willis, 2010).

2.4 Municipal Solid Waste Landfills

Municipal solid waste (MSW) landfills are used to dispose of household wastes and non-hazardous commercial and industrial wastes. The composition of this waste is approximately 62 percent organic material made up of yard trimmings, food scraps, wood, and paper (EPA, 2010a). When these organic wastes are deposited in the landfill they are compacted and covered. In this sealed environment they first undergo aerobic (with oxygen) decomposition until all available oxygen is depleted, this stage typically last less than one year. Once the oxygen runs out, the organic wastes start to undergo anaerobic decomposition. Anaerobic decomposition is the same biological process as anaerobic digestion except that it takes place inside the landfill as opposed to a digester. One of the products of this process is landfill gas which is composed of mostly methane and carbon dioxide. Landfill gas production depends on several factors, including: the amount of waste in the landfill, the composition of the waste, characteristics of the landfill receiving the waste (i.e. climate, moisture content), and the age of the garbage. Landfill gas is typically produced at a stable rate for 20 years, however gas will continue to be emitted for more than 50 years after the waste is placed in the landfill (U.S. Agency for Toxic Substances and Disease Registry (U.S. ATSDR), 2001).

Without a collection system, once landfill gas has been produced it migrates to the surface of the landfill and is released into the atmosphere. The emission of landfill gas into the atmosphere causes several adverse effects. The methane in the landfill gas poses a safety risk because of the possibility of an explosion and it is considered to be a greenhouse gas. Landfill gas also contains non-methane organic compounds (NMOC) which contribute to smog formation and threatens air quality. For these reasons the EPA regulates the emission of landfill gases under the Clean Air Act (CAA) New Source Performance Standards and Emissions Guidelines (NSPS/EG). The NSPS/EG states that landfills that can hold 2.5 million metric tons or more and emit 50 metric tons or more of NMOCs are required to install landfill gas collection systems and control landfill gas emissions (U.S. ATSDR, 2001).

The most common way in which landfill gas is collected is by drilling vertical wells into the landfill and connecting those wellheads into piping that transports the gas to a collection header using a blower or vacuum induction system (U.S. EPA, 2010b). Once the gas is collected it can be flared or treated and used for an energy project. Landfill gas can be used to generate electricity or used directly for its thermal capacity (used in boilers, furnaces, or kilns). According to the EPA's Landfill Methane Outreach Program (LMOP) database as of February 2013 there were 604 unique operational landfill energy projects in the U.S., with 446 using the gas to generate electricity and 158 using the gas for direct thermal purposes (U.S. EPA 2012).

Benefits associated with the use of landfill gas for an electricity generating project as opposed to just flaring the gas include the generation of renewable energy and a reduction of indirect GHG emissions by offsetting electricity generation by utilities. However, what drives the decision to implement an electricity project are the economic benefits. The main economic benefit of using landfill gas for electricity generation is that it helps to reduce the environmental compliance costs. If a landfill is required to install a gas collection and control systems it can go the extra step and install electricity generation equipment and use the revenues from the sale of electricity to help pay the capital costs associated with the gas collection and control systems.

The economic feasibility of the project will depend on capital costs, revenue from the sale of electricity, and financing costs. One factor that enhances the economic feasibility of an electricity generation project is that if landfill gas collection and control systems are already in place because of regulation requirements, they can be treated as a sunk cost and only modifications to the system need to be considered. Capital costs for installed landfill gas collection and control systems are approximately $25,772 (2012 dollars) per acre, and $4,402 per acre in operating and management costs (EPA, 2010b).

3. Procedures

3.1 Approach

The analysis begins by identifying "candidate" facilities that are technically suitable for the installation of a biogas electricity project. (This means excluding farms that have incompatible manure handling systems, WWTPs that do not have sufficient capacity, and MSW landfills that are too small to be required to have collection systems.) A capital budgeting model is used to estimate the net present value (NPV) of a biogas electricity project at each candidate facility.[2] The NPV of a project is calculated by discounting and summing all of a project's cash flows (positive inflows and negative outflows) to the present value. If the NPV is positive then the project is assumed to be economically feasible, and its generating capacity potentially available. A statewide estimate of the potentially available generation capacity can then be made by estimating the total generating capacity of facilities that would find the installation of a biogas electricity project economically feasible.

The revenue that these projects generate depends on the price they receive for electricity sales to the grid and the price that they pay for electricity purchases. Typically in the state of Indiana these projects receive the avoided cost rate for the electricity that they sell to the grid. The avoided cost rate represents the cost that the utility avoids by accepting the electricity supplied by the project, which is primarily the fuel cost of the marginal generating unit (EPA, 2004). Unless otherwise specified this report will assume that project owners receive the avoided cost for electricity they sell to the grid. The amount of electricity sold to the grid varies with each type of facility. CAFOs will typically utilize about half of the electricity that they generate and sell the remaining half to the utility. On the other hand WWTPs consume all of the electricity that they generate so all of the electricity is valued at the facility's purchasing rate. MSW landfills typically sell all of the electricity that they generate. Generation that is used to offset electricity purchases is valued at the facility's retail rate, which is assumed for livestock farms to be 8.6 ¢/kWh and for WWTPs to be 6.1 ¢/kWh. Other factors will vary according to the type of facility including taxes, debt interest rate, discount rate, and the percentage of the project financed with equity.

Three different types of incentive policies, similar to existing incentives for biogas electricity projects, are considered. An investment credit (IC) and a production credit (PC) are modeled

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[2] This type of model is based on the idea that a dollar today is worth more than a dollar one year from now, and that a constant annual discount rate can be used to express future dollars in terms of present value. For example, if one dollar received one year from now is worth \$0.80 today, then an annual discount rate of 25 percent is appropriate. That is, $\$0.80 = \$1.00/(1 + 0.25)$, and a dollar two years from now is worth $\$0.64 = \$1.00/(1 + 0.25)^2$.

after the investment tax credit (ITC) and the production tax credit (PTC) under the American Recovery and Reinvestment Act (ARRA) of 2009. An IC is a lump sum of cash equivalent to a prescribed percentage of the capital cost of the project that is paid to project owner. The ARRA of 2009 provides for an ITC of up to 30 percent. A PC is a cash payment for each kWh generated for the first ten years of production. The ARRA of 2009 provides for a PTC of 1.1¢/kWh. A feed-in-tariff (FIT) is an electricity price paid to renewable sources of energy that is above the retail price of electricity in order to encourage production.

3.2 Candidate Confined Animal Feeding Operations

For the purposes of this report, an anaerobic digester (AD) system refers to the anaerobic digester, gas treatment and electricity generation equipment. Only two types of livestock operations are considered: dairy and hog farms. This is because there have been very few AD systems installed at feedlot and poultry operations, and little is known about the technical and economic aspects of these operations. Dairy farms with fewer than 500 dairy cows and hog farms with fewer than and 1,000 hogs are excluded, because these facilities are typically considered too small to justify the installation of an AD system. Candidate CAFOs are identified by creating representative farms in specific size categories based on the 2007 Census of Agriculture and using the U.S. Department of Agriculture's 2009 Agricultural Resource Management Survey (ARMS) Hogs Costs and Returns Report (HCRR), and the 2010 ARMS Dairy Costs and Returns Report (DCRR) to determine how many farms are likely to be suitable for the installation of an AD system.

The EPA's AgSTAR FarmWare model version 3.6 is used to estimate the capital and operating costs, and the potential generating capacity of an AD system at each of the representative farms. Table 3-1 displays the number of candidate farms that were identified aggregated by the type and size of operation. It also includes the capital costs and the potential electricity generation capacity.

Operation type and size	Number of candidate farms	Capital costs ($2013)	Potential electrical generation capacity per farm (kW)
Dairy (500-999)	17	936,375	175
Dairy (1000-2499)	12	1,337,322	365
Dairy (2500 or more)	3	2,396,074	1,204
Hog farrow-to-wean (1000-1999)	4	523,002	22
Hog farrow-to-wean (2000-4999)	2	806,750	53
Hog farrow-to-wean (5000 or more)	2	1,473,390	184
Hog farrow-to-finish (1000-1999)	14	557,500	20
Hog farrow-to-finish (2000-4999)	14	817,909	43
Hog farrow-to-finish (5000 or more)	16	1,708,133	194
Hog finish only (1000-1999)	18	549,834	28
Hog finish only (2000-4999)	22	849,998	68
Hog finish only (5000 or more)	14	1,373,569	181
Hog nursery (1000-1999)	2	574,659	12
Hog nursery (2000-4999)	3	681,562	18
Hog nursery (5000 or more)	1	993,999	38
Total	144		2,605

Table 3-1: Number of Candidate Farms, Capital Costs and Potential Electricity Generation Capacity for Each Candidate Farm Category

3.3 Candidate Wastewater Treatment Plants

A candidate WWTP must have an average daily inflow of wastewater of at least 5 million gallons per day (MGD) (as previous analysis have found that facilities with inflows of less than 5 MGD do not produce enough biogas to make a CHP system technically feasible (U.S. EPA, 2011), the facilities must be operating an anaerobic digester for the processing of biosolids, and the facility must not have an existing energy project that uses the biogas. Based on data from the North East Biosolids and Residuals Association (NEBRA), 17 WWTPs in the state of Indiana were found to meet the criteria (NEBRA, 2012).

Capital and operating costs and the potential generation capacity of a Combined Heat Power (CHP) system at each facility were estimated using data from a report by the U.S. EPA. The report found that each million gallons of inflow can produce enough biogas to support 26 kW of electricity generation capacity for a CHP system (U.S EPA, 2011). Table 3-2 displays the candidate WWTPs and each facility's average daily flow, potential generation capacity, and estimated capital costs.

Facility name	Capital Cost ($2011)	Average flow (MGD)	Potential electricity generation capacity (kW)
Noblesville WWTP	520,000	5.0	130
Speedway WWTP	572,000	5.5	143
Shelbyville WWTP	707,200	6.8	177
Elkhart WWTP	863,200	8.3	216
J.B. Gifford WWTP	884,000	8.5	221
William Edwin Ross WWTF	936,000	9.0	234
Anderson WWTP	998,400	12.0	312
Mishawaka WWTP	998,400	12.0	312
Evansville Eastside WWTP	1,497,600	18.0	468
Muncie WWTP	1,580,800	19.0	494
Lafayette WWTP	1,718,080	20.7	537
Terre Haute WWTP	1,996,800	24.0	624
Hammond WWTP	2,246,400	27.0	702
City of South Bend WWTP	2,340,000	36.0	936
Gary Sanitary District	3,250,000	50.0	1,300
Fort Wayne WPCP	4,030,000	62.0	1,612
Carmel South WWTP	6,175,000	95.0	2,470
Total			10,888

Table 3-2: Candidate WWTPs, Capital Costs and Potential Electricity Generation Capacity for Each Candidate Facility

3.4 Candidate Municipal Solid Waste Landfills

A candidate MSW landfill must have a total design capacity of at least 2.5 million metric tons of garbage, be accepting waste or have closed within the past 5 years, and it must not already have an existing landfill gas project. Landfills that have a capacity of at least 2.5 million metric tons are required by the EPA to collect and control landfill gas, and hence, the costs associated with the gas collection system can be treated as sunk costs with respect to assessing the profitability of an electricity generation project. It must be accepting waste or have closed in the past 5 years because methane production decreases over time, and if a landfill has been closed for more than 5 years it shortens the length of the period during which gas will be emitted in large enough quantities to justify the installation of electricity generating equipment.

Data about the landfills came from the EPA's Landfill Methane Outreach Program (LMOP) landfill and project database and the Indiana Department of Environmental Management. Estimates for the capital and operating costs and the potential generation capacity came from the EPA's LFGcost-Web model. Table 3-3 displays the candidate MSW landfills and each facility's capital costs and potential electricity generation capacity.

Facility Name	Amount of garbage disposed on landfill (tons)	Capital costs ($2012)	Potential electricity generation capacity (MW)
Clinton county	1,170,254	1,331,114	560
New Paris Pike	1,900,000	1,938,470	870
Decatur Hills	1,363,442	1,995,869	900
Hoosier 2	2,143,024	2,240,354	1,030
Bartholomew county 2	1,468,927	2,516,165	1,170
Medora Sanitary	2,509,000	2,578,515	1,200
Wabash Valley	4,488,770	4,673,591	2,290
County Line	4,694,835	4,876,200	2,400
United Refuse	7,125,327	4,963,400	2,440
Sycamore Ridge	4,579,067	8,070,450	4,060
Total			16,920

Table 3-3: Candidate MSW Landfills, Capital Costs and Potential Electricity Generation Capacity for Each Candidate Facility
Source: U.S. EPA's LFGcost-Web Landfill Gas Energy Cost Model version 2.2

3.5 Technically Feasible Capacity

Table 3-4 displays along with the amount of biogas fired generating capacity that was found to be technically feasible in a report from the U.S. Department of Energy (DOE, 2004), the installed biogas powered electricity generating capacity as of June 2013, and the amount of additional generating capacity that this report found to be technically feasible.[3] The DOE report took into account fewer technical constraints when estimating the capacity from CAFOs and WWTPs, which explains why the DOE estimates are much higher than the estimates in this report. However, the DOE estimate for the generating capacity at MSW landfills is similar to the sum of

[3] Facilities that meet the criteria for candidacy in the previous sections are considered to be technically feasible.

currently installed plus additional technically feasible capacity. The 47.95 MW of additional technically feasible capacity represent 0.17 percent of the state's total generating capacity.

	2004 DOE estimate of additional technically feasible capacity (MW)	Installed capacity (MW) as of June 2013	Estimate of additional technically feasible capacity (MW)
CAFOs	123.00	9.05	20.13
WWTPs	66.00	0.20	10.89
MSW landfills	85.00	60.47	16.93
Total	274.00	69.72	47.95

Table 3-4: Estimates of Technically Feasible Biogas Generating Capacity

4. Results

4.1 Effect of Incentives

Figure 4-1 displays the amount of generating capacity that becomes economically feasible (from each sector and total) depending on the level of an investment credit (IC) as a percentage of capital costs. In general the results indicate that 37.10 MW of the technically feasible capacity are already economically feasible given the current operating conditions. However these results are sensitive to model assumptions, as will be discussed below. An IC is only moderately effective in making additional capacity economical with less than a 1.67 MW response at a level of 30 percent. An IC of 40 percent is a bit more effective resulting in additional economical capacity of about 7.66 MW. The figure shows that at a level of 20 percent, the IC is able to make all of the capacity at WWTPs (10.89 MW), MSW landfills (16.93 MW), and dairy farms (10.97 MW) economically feasible. We can observe that only at levels greater than 30 percent does the IC start to have an effect on hog farms. For all of the hog farms to be economically feasible an IC of over 80 percent would be required.

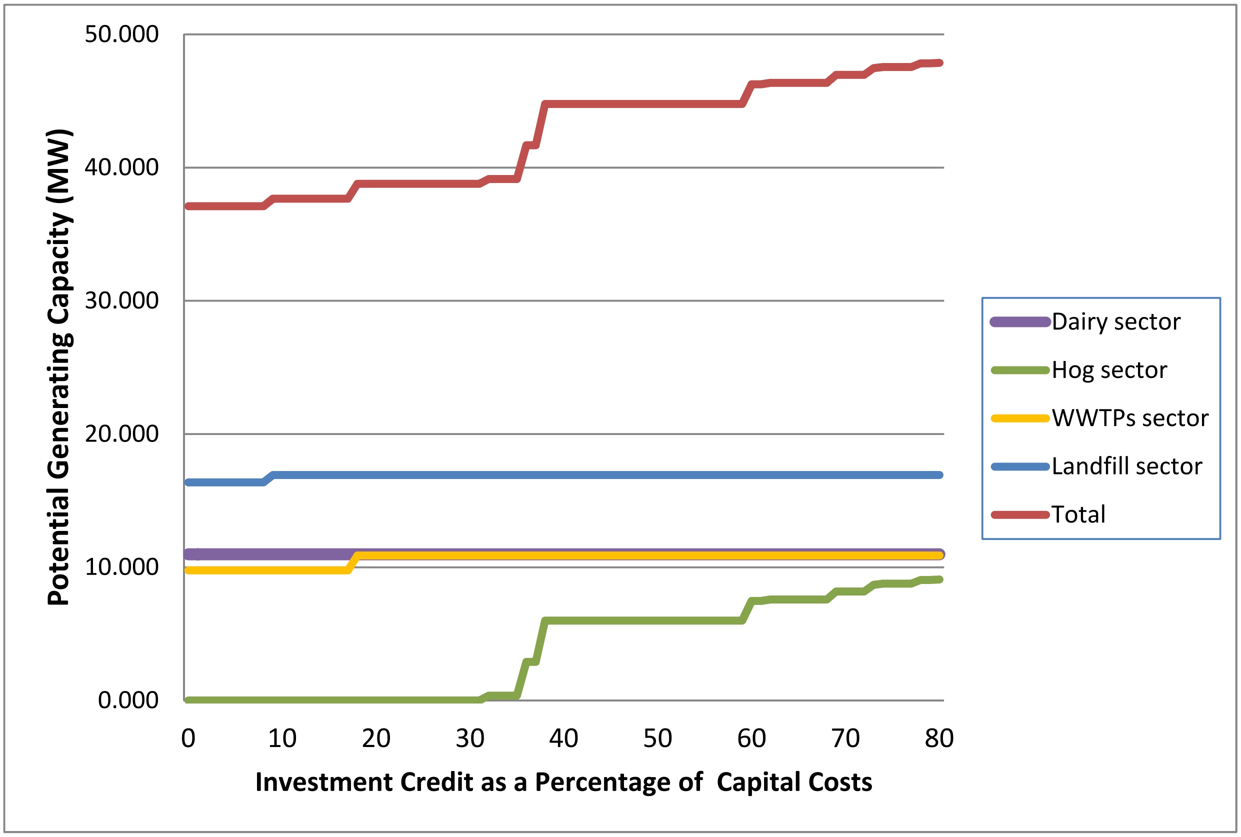

Figure 4-1: Additional Generating Capacity that Becomes Economically Feasible Depending on the level of the IC

Figure 4-2 displays the amount of generating capacity that becomes economically feasible depending on the level of the production credit (PC). This analysis is separate from the IC and assumes that the PC is the only incentive. As the figure indicates, there is very little response (less than 3 MW of additional capacity) for a PC up to 5 ¢/kWh. The PC is able to make all of the MSW landfill projects economically feasible at a level of 0.45 ¢/kWh (16.93 MW), and all of the WWTPs projects at a level of 1.36 ¢/kWh (10.89 MW). All of the capacity at the dairy farms (10.97 MW) is economically feasible without any incentive. The hog farms require a PC at levels greater than 4.73 ¢/kWh in order to become economically feasible. The PC would have to be as high as 84.20¢/kWh in order to make all of the projects at the hog farms economically feasible.

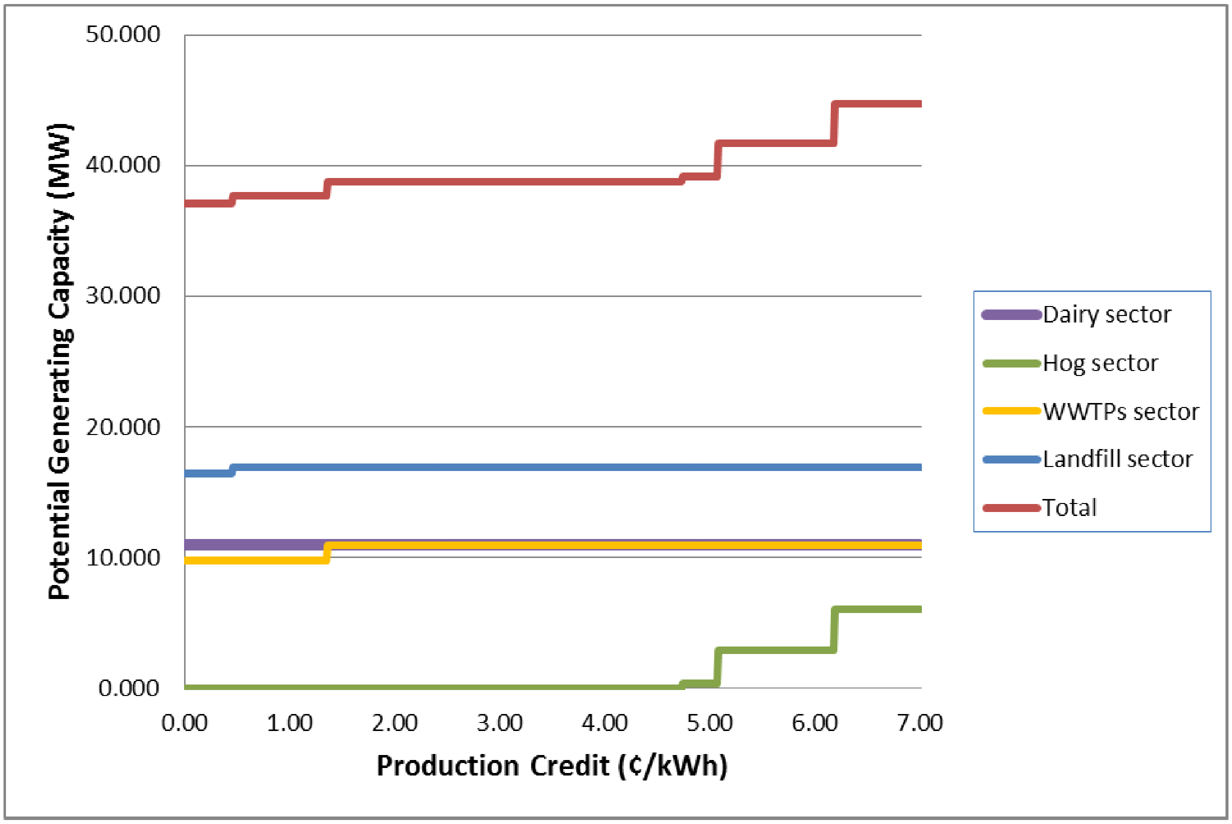

Figure 4-2: Generating Capacity that Becomes Economically Feasible Depending on the level of the PC

Figure 4-3 displays the amount of generating capacity that becomes economically feasible depending on the level of a feed-in-tariff (FIT) that is paid on a per kWh basis. The relevant range for the FIT is above the market price assumed in the analysis, which is indicated by the vertical line at a price of 4.30 ¢/kWh (this price represent the avoided cost rate). Responsiveness is significant at the lower price ranges with an increase of about 20 MW for FIT of 6.0¢/kWh. After this level gains are very modest with a gain of only 3 MW when the FIT is increased from 6.0 ¢/kWh to 12.0 ¢/kWh. Projects at hog farms start to become economically feasible at levels higher than of 10.90 ¢/kWh.

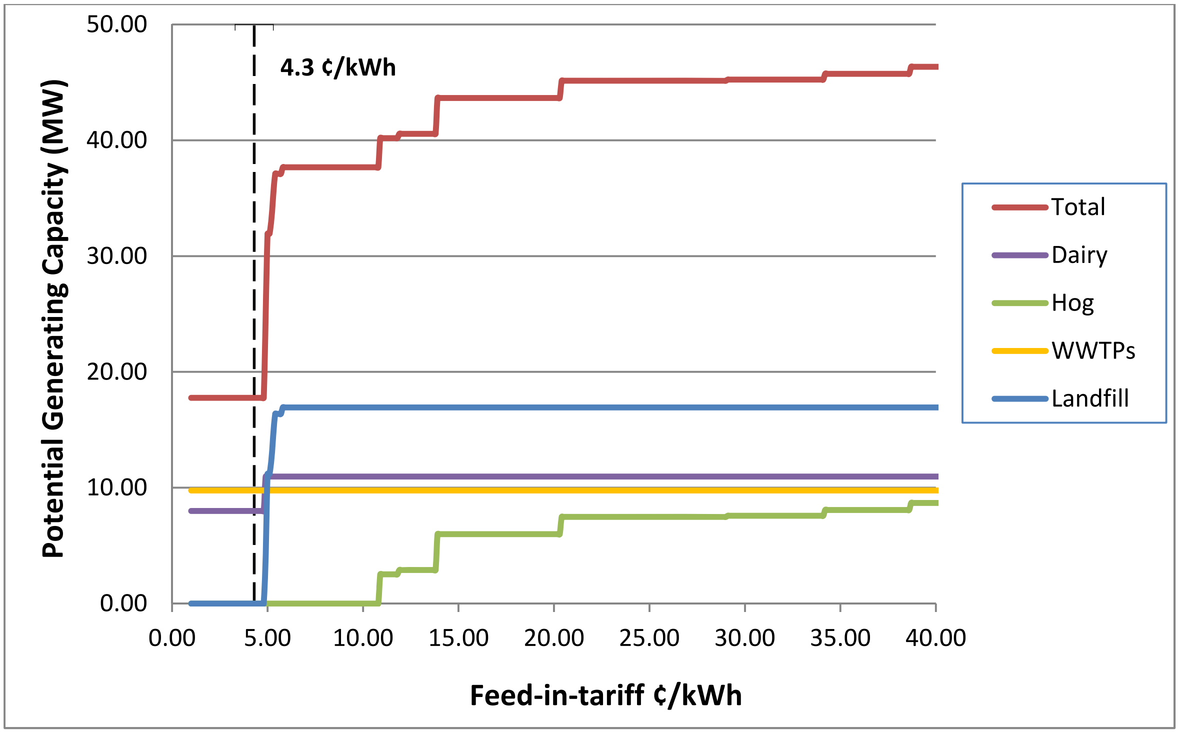

Figure 4-3: Generating Capacity that Becomes Economically Feasible Depending on the level of the Feed-in Tariff

4.2 Sensitivity Analysis

The capital cost estimates that were calculated for these projects came from sources that, while the best that are available, may be biased downwards. To compensate for this possibility a sensitivity analysis was used to determine how robust the results were to the capital cost estimates. Figure 4-4 displays the level of incremental capacity that would be economical under alternative incentives for three different scenarios – the base (original capital costs), capital costs that are 10 percent higher than the base, and capital costs that are 20 percent higher than the base. We can observe that the 37.10 MW of capacity that are economically feasible without any incentives are very sensitive to the assumed level of capital costs. If capital costs were to be 20 percent higher the amount that becomes economically feasible drops to 14.31 MW. However, when any of the incentives are available the results are less sensitive to increases in capital costs, and the higher the incentives the more robust the results become.

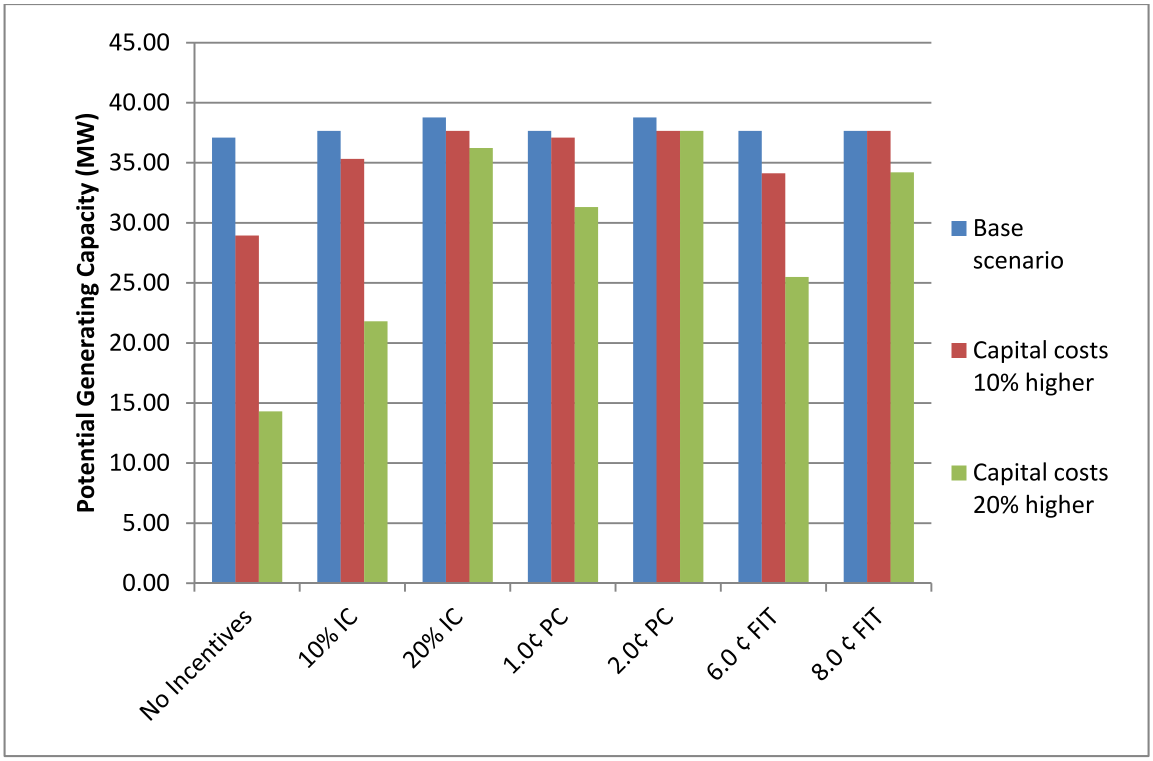

Figure 4-4: Sensitivity Analysis with Respect to Capital Costs

4.3 Policy Alternatives

Table 4-1 displays different incentive levels, the corresponding amount of technical capacity that becomes economically feasible, the costs of the incentives assuming all of the capacity that is economic feasible is installed and the amount of CO_2 emissions that would be displaced from generation at conventional power plants. The table also included the potential value of those emissions offsets as a way to measure the benefits that would be realized by subsidizing biogas electricity projects. Other benefits would accrue but are hard to measure because they do not have market value such as odor control and a slowing of the exhaustion of fossil fuels. When considering policy alternatives things that have to be taken into account are the effects of the policy, the robustness of the results, and the cost of the incentives. The lowest cost option would be to provide no incentives. The results indicate that there would be 37.10 MW of generating capacity would be economically feasible. However, the results are very sensitive to capital cost assumptions. The next lowest cost options are the 10 percent IC or the 6.00 ¢/kWh FIT, both of which are still fairly sensitive to capital cost assumptions. The 20 percent IC is the lowest cost option that offers robustness against capital cost assumptions.

	Potential generating capacity (MW)	Total incentive cost ($)	Incentive cost ($/MWh)	Displaced emissions[(a)] (metric tons of CO2 equivalent)	Potential value of emission offsets[(b)] (assuming $13.00 per metric ton)
No incentive	37.1	-	-	3,030,917	39,401,921
10% IC	37.66	10,234,852	2.18	3,253,536	42,295,962
20% IC	38.78	21,420,780	4.45	3,335,220	43,357,860
30% IC	38.78	32,131,170	6.68	3,335,220	43,357,863
1.00 ¢/kWh PC	37.66	25,080,148	5.35	3,253,536	42,295,968
2.00 ¢/kWh PC	38.78	51,534,223	10.71	3,335,220	43,357,860
3.00 ¢/kWh PC	38.78	77,301,335	16.07	3,335,220	43,357,860
6.00 ¢ FIT	37.66	13,811,845	2.94	3,253,536	42,295,968
8.00 ¢ FIT	37.66	61,060,240	13.01	3,253,536	42,295,968
10.00 ¢ FIT	37.66	108,308,635	23.08	3,253,536	42,295,968

Table 4-1: Policy Alternatives Benefits and Costs

(a) Each MWh produces 1528.76 lbs. of CO_2 equivalent. Source: U.S. EPA, 2012b
(b) California carbon futures were trading at $14.70 per metric ton of CO_2 on April 9, 2013. Source: Bloomberg, 2013.

It is also important to consider the way in which the different incentives work in order to choose the most appropriate incentive. The ICs are a lump sum of money that is paid out at the time when the investment is made. However there is no guarantee that a project will operate for the full project lifespan or at the highest capacity factor possible. Maintenance costs are lumpy in nature and large maintenance expenses may occur with several years left in the project. At that point it may be optimal for the operator to avoid large maintenance expenses because they would not be recovered by the end of the project. If the equipment is not operated for the entire project lifespan the cost per MWh with the ICs would be higher. On the other hand FITs are a "pay for performance" incentive that only pays for actual electricity output. The operators have an incentive to generate electricity for the entire length of the project. If the equipment is operated at lower capacity factors or the projects run for a shorter timespan the incentive cost would commensurately decrease.

The results indicate that the incentives needed to make AD systems at hog farms economically feasible would be very expensive and far above the levels of the incentives currently being offered for other renewable technologies. It would be too expensive to pursue these projects in the present, and it might make more sense to wait until the technology develops further. That being the case an alternative policy could be to offer a 6.50 ¢/kWh feed-in-tariff to CAFOs and

MSW landfills, and a 20 percent IC for WWTPs. This policy would make all of the projects at the dairy farms, MSW landfills, and WWTPs economically feasible (38.79 MW) at a cost of 6.99 $/MWh for the CAFOs and the MSW landfills, and 5.81 $/MWh for the WWTPs. This policy would provide for robust results and a lower risk for the tax payer or rate payer (because of the pay for performance incentive).

It is important to consider any possible unintended consequences that the subsidy may have on the biogas electricity sector and in the different sectors considered in this report. Both anaerobic digesters and generating technologies such as microturbines have experienced technological improvements in recent years. Subsidizing expansion of a technology could negatively impact the industry in the long term by diverting resources from research and development into expanding production, and decreasing the rate of technical progress. There could also be unintended consequences in the other industries. The results indicated that biogas electricity projects are more likely to be profitable in the larger livestock operations. If these projects are subsidized this could benefit the larger farms and encourage further consolidation and a continued growth of farm sizes. In the landfill sector it could divert organic wastes such as paper from recycling to landfills.

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