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Carbon Emissions, Renewable Electricity and Profits:
Comparing Alternative Policies to Promote Anaerobic Digesters on Dairies

Nigel Key and Stacy Sneeringer[*]

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Abstract:

Biogas recovery systems that use methane from manure to generate electricity have not been widely adopted in U.S. mainly because the costs of constructing and maintaining these systems have exceeded the value of the benefits provided. Climate change mitigation and renewable energy policies could increase profits for the operators of such systems thereby making digester adoption more widespread. For the U.S. Dairy sector, we examine digester adoption rates, emissions reductions, net returns, electricity generation, and program costs under different policy scenarios. We find that 3% or fewer dairies would need to adopt digesters to meet the policy goals of reducing 25% of greenhouse gas emissions from dairy manure or generating one million megawatt hours of electricity per year. A carbon pricing program provides the highest net social benefits for almost all policy goals considered.

Keywords: anaerobic digester, methane, dairy, renewable electricity, subsidy, carbon offsets, climate change

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[*] Senior authorship is shared. The authors are economists with the Economic Research Service of the U.S. Department of Agriculture. The views expressed are the authors' and do not necessarily reflect those of the Economic Research Service or the USDA. Please direct correspondence to: Nigel Key, 1800 M St. NW, Washington, DC 20036. nkey@ers.usda.gov.

Anaerobic digesters that collect and burn methane from manure can provide numerous benefits to livestock producers and the environment. They can supply a renewable source of electricity that can be used on the farm or sold. Digesters can reduce odors from manure, lower the potential for surface water contamination, and be used to recycle manure solids for animal bedding material. By burning methane, digesters can also reduce greenhouse gas (GHG) emissions from manure management. Despite these benefits, anaerobic digesters have not been widely adopted in the U.S.: currently, there are only 157 digester operating systems, of which 126 are on dairies and 24 on hog operations (USEPA, 2010a).

Increasing fuel prices, a focus on renewable energy, and a desire to reduce carbon emissions have renewed interest in policies to encourage capturing methane emissions from livestock manure to produce energy. A 2010 Environmental Protection Agency (EPA) – U.S. Department of Agriculture (USDA) joint statement announced the agencies' intention to provide $3.9M to encourage farm adoption of biogas recovery systems that generate energy from manure-based methane. The EPA estimates that 6,900 farms could feasibly generate 6.3 million kWh of electricity annually from biogas (EPA, undated). Cap-and-trade climate legislation like that recently debated in Congress (HR 2454, the American Clean Energy and Security Act of 2009) could also encourage the adoption of farm-based methane digesters as producers gain the ability to sell offsets in the proposed carbon market. Under the proposed cap and trade system, livestock producers who reduce methane emissions from their operations could sell carbon offsets to other greenhouse gas emitters (such as electric utilities) who face emissions caps.

Despite the apparent political desire to encourage biogas capture at livestock facilities, little empirical research accounting for costs and benefits examines which policies could induce widespread voluntary adoption of digesters and what these policies' subsequent impacts may be.

The EPA study identifying the 6,900 farms that would find it "profitable" to adopt digesters explicitly notes that it does not include a cost analysis (EPA, undated, p. 4), instead defining profitability on the basis of size and manure management method. Other studies have examined the economic attractiveness of digesters for particular types of farms (Lazarus and Rudstrom, 2007; Leuer, Hyde, and Richard, 2008; Stokes, Rajagopalan and Stefanou, 2008; and Bishop and Shumway, 2009). While useful, these studies may not be sufficiently generalizable to predict nation-wide adoption levels. Only Gloy (2010) and Key and Sneeringer (2011) consider national adoption rates of digester systems, but both studies focus primarily on the climate change policy and the carbon price and do not explore alternative policies to promote digester use.

There are several policy approaches that could make digesters more profitable for operators. Policies currently in use include: 1) construction cost subsidies (e.g., loan guarantees, accelerated depreciation, cost-share programs); 2) policies that raise demand for, and hence the price of, digester-generated electricity; and 3) carbon offset markets. We estimate and compare the effects of these alternative policy approaches in terms of operator net returns, digester adoption, electricity generation, GHG emissions, and program costs. We also estimate the social net benefits of these alternative policies under various assumptions about the social benefits to renewable energy and GHG emission reductions. The analysis highlights some of the potential long-run implications and unintended consequences of these alternative policy approaches.

We develop a model of digester profitability based on farm size; manure management method; electricity price, generation, and use; and digester capital and variable costs to estimate how government cost-sharing, policies affecting electricity pricing, and the development of a carbon offset market affect producers' decision to adopt biogas recovery systems. We parameterize the model using multiple case studies to reflect actual farm-level costs and experiences with energy production using digester technology, and then use state-level data from government sources to account for regional variation in electricity prices, methane emissions, and energy source. We apply the model to Agricultural and Resource Management Survey (ARMS) data for dairies to predict adoption levels under different policy scenarios and assumptions about the social benefits of greenhouse gas emission reductions and renewable energy.

We find that few dairies would need to adopt digesters to meet our policy goals of reducing 25% of GHG emissions from dairy manure or generating one million Mwh of electricity per year. Reducing GHG emissions from dairy manure management can be achieved most efficiently with a carbon pricing policy (like an offset program). Meeting specific electricity generation target amounts (including energy replaced on-farm) can be achieved at the lowest cost with a capital cost-share program; a subsidy for renewable energy is most efficient at meeting specific amounts of digester-generated electricity for sale. Electricity subsidy programs do not lead to an overall net increase in carbon emissions, although they can induce some individual farms to increase their emissions. A carbon pricing program provides the highest net social benefits for almost all policy goals.

Methane Creation and Capture on Livestock Operations

Livestock generate large amounts of manure that must be stored, spread on fields, or moved off-farm. Manure mixed with water is often stored in lagoons, ponds, tanks, or pits, creating anaerobic conditions. The decomposition of livestock or poultry manure without oxygen produces a biogas containing about 60% methane.[1] When manure is handled as a solid or

[1] The remaining gas consists primarily of carbon dioxide (about 40%), plus small amounts of toxic gases, including hydrogen sulfide, ammonia, and sulfur derived mercaptans (ATTRA, 2006).

deposited on fields it tends to decompose aerobically and produces much less methane. The quantity of methane released also depends on climate (temperature and rainfall) and the conditions under which manure is managed (oxygen level, water content, pH, and nutrient availability).

Methane is a potent greenhouse gas, with one ton of methane having 25 times the global warming potential as one ton of carbon dioxide. In 2008, methane emissions from manure management were responsible for about 10.5% of GHG emissions from the agriculture sector.[2] Agriculture as a whole was responsible for 6.1 percent of total U.S. greenhouse gas emissions (EPA, 2010, p2-12).[3] Dairy cattle and swine producers, who often use anaerobic (without oxygen) manure management systems, were responsible for 43.1% and 43.6% of methane emissions from manure management, respectively (EPA, 2010, table 6-3). Beef cattle, sheep, poultry and horses were collectively the source of only 13.3% of total manure methane, mainly because manure from these animals is usually handled in aerobic (with oxygen) conditions.

A biogas recovery system, known as an "anaerobic digester," "methane digester," "biodigester," or "methane recovery system," can be used to capture methane from anaerobic manure storage facilities.[4] Such systems collect manure, optimize it for the production of methane by adjusting temperature and water content, and capture the biogas. The captured methane can then be burned for heat or, with the addition of a generator, can be used to produce electricity. By burning methane, its global warming potential is reduced from the equivalent of 25 tons to 1 ton of carbon dioxide.

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[2] Livestock also emit methane from enteric fermentation produced during digestion. In 2008, over three times as much methane was released from enteric fermentation as from manure management (EPA, 2010, table 2-8).
[3] This total does not include emissions from inputs to agricultural production that are attributed to other sectors, including fertilizer production, transportation, and electricity generation.
[4] Anaerobic "digestion" occurs when bacteria break down (or "digest") biodegradable material such as manure without the presence of oxygen.

Anaerobic digesters are generally added to two main types of manure storage. These are "lagoon"-based systems in which a cover is placed over an earthen storage pond, and "pit"-based systems in which manure is processed through a heated tank to encourage methane production. Operations with aerobic manure storage systems, such as a stacking slab, or those that do not store manure generally do not produce enough concentrated methane from manure to make a digester feasible.

There are three main types of digesters: complete-mix, plug flow, and covered lagoon. A complete-mix digester is a large concrete or steel container, usually circular in shape. A plug-flow digester is often in the shape of a trough and built below ground level, with an air-tight expandable cover. Manure is collected daily and added to one end of the trough, and this "plug" slowly pushes the existing manure down the trough. A covered lagoon digester is an earthen lagoon fitted with an impermeable cover that rests on the surface of the lagoon. The industrial fabric cover collects biogas as it is produced from the organic wastes.

Methane digesters have not been widely adopted because the costs of constructing and maintaining these systems have exceeded the benefits they provide to the farm operator. Construction costs for digesters are significant. Total capital construction costs include costs of the design, manure collection and pretreatment, lagoon cover, tank, generator, and utility connection. A review of 23 case studies (Key and Sneeringer, 2011) suggests that costs range from $160K to $2.5M, and average $713 per cow.[5] Covered lagoon digesters are generally less expensive to construct than complete-mix and plug flow digesters, but lagoon digesters cannot be heated to increase methane output in cooler climates.

Non-Policy Factors Affecting Digester Adoption

[5] Values in 2009 dollars. For details of these case studies, see Key and Sneeringer (2011).

The decision to adopt a digester depends on a number of factors including the manure management method employed, the size of the operation, the start-up and ongoing costs of the technology, the price of electricity, on-farm electricity expenditures, the amount of electricity that can be generated, and the physical capacity to sell electricity not used on the farm.

Manure management method and operation size are the two primary factors affecting digester adoption. A concentrated supply of methane is necessary for the effective running of a digester. As such, only operations that store manure in anaerobic conditions generating significant quantities of methane are viable candidates for biogas recovery systems (unless an operation converts to a different management method). About 50% of dairies have an anaerobic manure system, 16% use an aerobic system (open slab or covered shed), and 34% report having no manure storage system.

Anaerobic manure management systems are generally less common on small-scale operations. For example, only 46.0% of dairy operations with fewer than 250 head use anaerobic manure management systems compared to 73-88% of operations in larger size categories (table 1). Larger operations are also more likely to have lagoon manure systems, which have higher initial methane emission rates than pit systems.

Farm size is an important determinant of digester profitability because it is associated with manure management methods and because of economies of scale in construction and maintenance of methane digesters. As illustrated by the case study data described later in the paper, the costs of constructing the storage facility and generator generally decline on a per-unit basis with the size of the operation. Finally, there are numerous fixed transactions costs associated with selling electricity or certifying and marketing offsets that do not vary substantially with farm size. Larger operations can spread these fixed costs over a larger revenue base.

Whereas type of manure storage and size largely decide the technical feasibility of a digester on an individual farm, other non-policy factors help determine profitability. Electricity use, generation, and price are key factors determining methane digester profitability as they determine the costs savings from farm-generated electricity and the revenues that can be earned from the sale of surplus electricity.

An average dairy with 154 head of cows uses 128,918 kWh of electricity per year, or 837 kWh per head.[6] However, there is significant variation in energy usage across farm sizes, with larger operations using substantially less electricity per-head than smaller operations (table 1). There is also significant variation across regions in electricity use: on average, dairies used 1,102 kWh of electricity per head in the Midwest, compared to only 791 kWh per head in the South, reflecting both differences in average operation size and climate.

Another pertinent factor in digester profitability is the ability to sell generated electricity to the grid. If operations are unable to sell surplus electricity back to the grid, then the benefits from electricity generation are limited to the avoided on-farm energy costs associated with heating or cooling, drying grain, pumping water, lighting and operating dairy or other machinery. In addition to being able to physically connect to the grid, another key determinant of digester profits is the price received from the utility company for the electricity generated and sold. To some extent this price will depend on policies established at the local, state, or federal level. In the next section, we discuss some key policies affecting the electricity price.

Finally, climate can affect the amount of methane generated (particularly for lagoon-based systems), and thereby determine the amount of electricity generated. More methane is

[6] Authors' calculations using ARMs data.

emitted from anaerobic systems at higher temperatures, so digesters in warmer climates will be able to generate more electricity, and provide more emissions reductions that could be sold in a carbon offset market.

Policies Affecting Digester Profitability and Adoption

There are several policy approaches that can be taken to make digesters more profitable and encourage their adoption. Approaches currently in use include: construction cost subsidies; operating cost subsidies; policies that raise demand for, and hence the price of, digester-generated electricity; and carbon pricing mechanisms. Other potential policies and programs include emissions performance standards and manure management technology standards that require installation of a digester.

In this paper we compare the effects of three alternative policies that are currently in use: 1) a construction cost-share subsidy, 2) an electricity selling price subsidy, and 3) a carbon price (offset) policy. We evaluate these alternatives in terms of operator net returns, digester adoption rates, program costs, electricity generation, and GHG emission reductions.

Construction costs subsidies

Construction cost subsidies can take a variety of forms, including grants (e.g. the US Department of Agriculture Rural Energy for America Program Grants), tax credits (e.g., the Renewable Electricity Production Tax Credit), accelerated depreciation (Accelerated Cost Recovery System, which allows qualifying renewable energy systems to be depreciated using an accelerated schedule for tax purposes), or property and sales tax exemptions (usually at the state level).

Typically cost-share programs are capped at a particular level. For example, the Rural Energy for America Program Grants/Renewable Energy Systems/Energy Efficiency

Improvement Program (REAP/RES/EEI) grants can be up to 25% of total eligible project costs and are limited to $500,000 for renewable energy systems.[7] However, it is possible for operators to obtain grants or subsidies from multiple sources making it difficult to determine a broadly representative cut-off point.

Electricity price subsidies

Methane is a biogas that qualifies as a renewable energy source, so digester owners could obtain Renewable Energy Certificates (RECs) for the electricity they generate and supply to the grid. RECs are allocated by a certifying agency to renewable energy providers. Providers then feed the renewable energy into the electrical grid and sell the accompanying RECs in a market. Customers can buy RECs whether or not they have access to renewable power through their local utility and can purchase RECs without having to switch electricity suppliers. The buyers of RECs have effectively purchased renewable energy, because the sellers of the RECs - the producers of renewable energy - receive revenue from the REC sales (USDOE, 2011). Hence, sales of RECs provide a production subsidy to generators of renewable electricity.

There are two main types of markets for RECs – compliance and voluntary. Compliance markets for RECs have been established in the 30 states having a Renewable Portfolio Standard (RPS) (a RPS is sometimes called a Renewable Electricity Standard). A RPS is a mechanism for obliging a utility to supply a specified fraction of their electricity from renewable energy sources. The utility can satisfy a RPS by purchasing RECs from renewable energy producers.

In 2009, the U.S. Senate passed out of committee federal legislation that would have, among other things, required electric utilities nationwide to meet 15% of their electricity sales through renewable sources of energy by 2021. However, this legislation, the "American Clean Energy Leadership Act," was not enacted into law. At the state level, there is a wide variety of

[7] For more information: http://www.rurdev.usda.gov/rbs/busp/9006grant.htm

renewable energy targets and technology standards. Taking the largest dairy states as examples, California has a RPS requiring 20% of electricity be from renewable source in 2010, which increases to 33% in 2020. Wisconsin has the goal of achieving 10% of its electricity from renewable sources by 2015.

In voluntary REC markets, customers (usually corporation or households) voluntarily choose to buy renewable power. Renewable energy generators located in states that do not have a RPS can sell their RECs in voluntary markets, usually at a lower price than in compliance markets.

Prices for RECs depend on a number of factors, including the local supply and demand for RECs. The average unweighted residential price premium for RECs in 2010 was $18.90/MWh (or about $0.02/kWH) (National Renewable Energy Laboratory, 2010).

Pricing GHG emissions reductions

One approach to mitigate greenhouse gas emissions from manure management is to pay farmers for emissions reductions. Farmers could be compensated directly with government payments or through carbon offset sales. As with RECs, carbon offsets can be exchanged in compliance or voluntary markets. Compliance markets usually operate in conjunction with a cap-and-trade regime that places a legal limit on the quantity of greenhouse gases that can be emitted by regulated firms in a particular time period. Under such a system, regulated firms must obtain permits to emit greenhouse gases. To meet their emissions targets, regulated firms could reduce their own emissions or purchase permits from other “capped” firms. Alternatively, firms could pay non-regulated emitters, such as livestock operations, to reduce emissions – i.e., the firms could purchase offsets.

Compliance markets have been established at the international, national, and regional levels. Regimes that govern international compliance markets include the Kyoto Protocol and the European Union's Emissions Trading Scheme. In the U.S., ten eastern states recently implemented the Regional Greenhouse Gas Initiative (RGGI), the first mandatory market-based effort in the U.S. to reduce greenhouse gas emissions. Under the RGGI, the capped sector (power generation) can purchase emission offsets from other sectors such as agriculture that reduce or sequester greenhouse gas emissions. Projects that reduce methane emissions from manure management are eligible for offset allowances. In 2009, the U.S. House of Representatives approved climate change legislation (H.R. 2454, the American Clean Energy and Security Act of 2009) that, if signed into law, would have established a national cap-and-trade system and provided a further opportunity for farmers to sell offsets from reducing their manure methane emissions.

Voluntary offset markets function outside of compliance markets and allow companies and individuals to voluntarily purchase carbon offsets. For example, individuals might seek to offset their travel emissions or firms might seek to compensate for emissions related to their production. In the U.S., the Chicago Climate Exchange (CCX) is a voluntary, but legally binding, carbon trading regime. In this privately administered cap-and-trade system, methane emissions reductions from livestock operations can qualify as offset projects.

The offset revenue that a livestock operation could earn from a digester system depends on the type of manure storage and handling facility that an operation has been using. Offset programs usually require documentation of baseline emissions and certification that offsets are for emissions reductions that are below the baseline. Consequently, only operations that had been using an anaerobic manure storage facility before the creation of an offset market would likely qualify for an offset program. This largely limits the pool of potential offset market participants to swine and dairy operations having lagoon or pit systems. Operations with slab or shed manure systems or with no storage facilities would not generate sufficient methane to satisfy the "additionality" requirements for offset certification – that is, a digester project would not reduce emissions below the baseline.

In the major international compliance markets, carbon offset prices have ranged between \$15 and \$30 per ton of carbon dioxide equivalent emissions in the last decade.[8] In overseas voluntary markets, prices have generally been somewhat lower – ranging between \$5 and \$15/tCO_2e. In the U.S., offset prices have been lower. The average price for carbon allowances in the RGGI has ranged between \$1 and \$3/tCO_2e between 2008 and 2010.[9] The CCX carbon price has ranged between \$1 and \$7/tCO_2e since 2004, but has been trading at its floor price under \$1/tCO_2e between 2009 and 2010.[10] There is a great deal of uncertainty as to the eventual carbon price under a national cap-and-trade system. The EPA estimated that in the near-term, the proposed House bill (H.R. 2454) would have resulted in a price of \$13/tCO_2e of carbon dioxide equivalent emissions (USEPA, 2009). However, the carbon price could fall short of or exceed this level over the medium or long term.

Climate change legislation that raises the price of carbon could also be expected to increase electricity prices. Regions where electricity is generated using more carbon-intensive methods would likely see larger price increases.

Other policies affecting digester adoption

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[8] Offsets are measured in tons of carbon dioxide equivalent emissions (tCO_2e). Reductions in other greenhouse gases such as methane are converted to an equivalent quantity of carbon dioxide based on that gas's relative global warming potential.

[9] See Regional Greenhouse Gas Initiative, *Market Monitor Reports*, http://www.rggi.org/market/market_monitor

[10] See Chicago Climate Exchange, *CXX Carbon Financial Instrument Contracts Daily Report*, http://www.chicagoclimatex.com/market/data/summary.jsf

A “net metering” law is another policy that could influence digester adoption by changing the value of generated electricity for the producer. Under net metering, when surplus electricity is produced on-farm, the electricity meter spins backwards, effectively saving the electricity until it is needed. Over the billing period, the operation is only billed for its net electricity usage. This eliminates concerns of when the electricity is produced and differential pricing over the course of a day.

Net metering laws vary widely across the forty states that have adopted them (DSIRE, 2010). In some states there is a maximum generator size that is eligible for net metering, which may be below the optimal size used with a digester. Operators in states facing a binding generator size limit will obtain a lower value for their generated electricity. Consequently, without net metering, operations may not obtain the retail price for the electricity they generate but do not consume. In this analysis, we assume that net metering is available for all operations, and do not consider the effect of altering this assumption.

Empirical Framework

Recent studies that have modeled the economic benefits and costs of methane digesters include Lazarus and Rudstrom (2007), Leuer, Hyde, and Richard (2008), Stokes, Rajagopalan and Stefanou, (2008), and Bishop and Shumway (2009). These studies focus on particular regions, markets, or types of farms, and do no attempt to estimate nation-wide digester adoption rates or profits. Exceptions are Gloy (2010) and Key and Sneeringer (2011) who develop models of digester profitability in order to estimate the potential supply of carbon offsets from the sector. Key and Sneeringer also explore the distributional implications of such a policy. The modeling approach used here in this study is similar to these studies, but we extend the model in several ways as detailed below.

Our basic approach is to model the profitability of digesters and then predict, using nationally representative data, adoption rates and other outcomes under various policy scenarios. We use the net present value (NPV) to assess the profitability of a digester project. The NPV is the sum of all future cash flows (e.g., revenues from electricity or carbon offsets minus capital and variable costs) discounted to their present values. If the NPV of the digester project is positive, we assume that the operator adopts.

We establish five policy "goals" and then use the investment model applied to the data to determine 1) the level of policy intervention needed to meet the goal, 2) the adoption rate of digesters among producers, 3) the amount of electricity generated by the digesters, 4) the amount of electricity sold by the digesters, 5) carbon emissions reductions, 6) digester net revenues accruing to the farmer, and 7) the total cost of the policy. The five policy goals that we consider are 1) reducing by 25% and 75% the carbon emissions from dairy manure management, 2) generating 15 million and 45 million Mwh of electricity over 15 years, 3) selling 5 million and 10 million Mwh of electricity over 15 years, 4) achieving a digester adoption rate on dairy operations of 10% and 20%, and 5) limiting the 15-year policy cost to $1B and $5B.

Once we have estimated the outcomes for these various policy goals, we can also estimate the social benefits of each policy. To do this we assign a social price of $0.02/KWh for generated electricity, which is the average residential price premium for renewable energy certificates.[11] For GHG emissions reductions we use the price of $13/tCO2e, which is the estimated price of a carbon offset under a national emissions trading regime (EPA, 2009).

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[11] National Retail Renewable Energy Certificate Products (last updated August 2010), National Renewable Energy Laboratory. Accessed April 15, 2011 at: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

Investment Model

Operators face different decisions with regards to policies based on their present manure management method (see Fig. 1). Producers with anaerobic manure management systems face a decision to adopt a methane digester with an electricity generator, adopt a digester without a generator and just flare collected methane, or not adopt either technology. If such a producer adopts a digester with an electricity generator, then s/he has the additional choice of whether to sell offsets or not. Producers with aerobic manure management systems can decide to do nothing, or convert their systems to either lagoon or pit-based anaerobic systems and sell electricity. These producers would not satisfy "additionality" requirements of offset programs and therefore could not sell offsets; hence flaring would not be a profitable option.

Allow RE_{isft} to denote the value of electricity generated by a digester and generator for operation i, located in state s, using manure management facility type f, in time t. RO_{isft} is the value of offset sales. CD_{ift} is the cost of the digester plus the electricity generator, and CO_t is the cost to sell offsets. Allow γCD_{ift} to be the cost of a digester without the electricity generator, where $0 < \gamma < 1$. Finally, allow T to represent the lifespan of the digester and d to represent the discount rate.

An operator with an anaerobic manure management system who is considering investing in a methane digester chooses between four outcomes based on the maximum of the expected discounted stream of net revenues of each:

a) $\sum_{t=0}^{T}[(RE_{isft} + RO_{isft} - CD_{ift} - CO_t)/(1+d)^t]$; build a digester with an electricity-producing generator and sell offsets.

b) $\sum_{t=0}^{T}[(RE_{isft} - CD_{ift})/(1+d)^t]$; build a digester with an electricity-producing generator but do not sell offsets.

c) $\sum_{t=0}^{T}[(RO_{isft} - \gamma CD_{ift} - CO_t)/(1+d)^t]$; build a digester without a generator, flare the collected methane, and sell offsets.

d) 0; do not adopt a digester.

An operator with a current aerobic manure management system can decide to switch to one of two anaerobic systems, but would not be eligible to sell offsets based on additionality rules. Allowing $f = 1$ to denote a lagoon manure management type and $f = 2$ to denote pit-based manure management type, and W_{ift} to denote the cost of switching systems. An operator with an aerobic manure management system who is considering investing in a methane digester chooses between three outcomes based on the maximum of the expected discounted stream of net revenues of each:

a) $\sum_{t=0}^{T}[(RE_{is1t} - CD_{i1t} - W_{i1t})/(1+d)^t]$; switch to a lagoon system and adopt a digester with an electricity-producing generator.

b) $\sum_{t=0}^{T}[(RE_{is2t} - CD_{i2t} - W_{i2t})/(1+d)^t]$; switch to a pit system and adopt a digester with an electricity-producing generator.

c) 0; do not switch manure management methods and do not adopt a digester.

The value of electricity generated by the digester RE_{isft} depends on time and on whether the quantity generated on-farm E_{if}^{G} is less than or greater than the quantity used on-farm E_{i}^{U} as well as the buying ("retail") and selling ("wholesale") prices of electricity, P_{s}^{ER} and P_{s}^{EW} (respectively). In the event that the selling price is above the retail price, the producer will sell all electricity generated and buy back any needed electricity at the retail price, regardless of whether s/he generates more electricity than is used on-farm (this is equivalent to selling RECs for the full amount generated). If the buying price is above the selling price, then the producer uses digester-generated electricity to replace any on-farm needs; if more electricity is generated than used, this amount is sold at the wholesale price:

$$(1) \quad RE_{isft} = \begin{cases} 0 & \text{if } t = 0 \\ P_s^{EW} \cdot E_{isf}^G & \text{if } 1 \leq t \leq T \text{ and } P_s^{ER} < P_s^{EW} \\ P_s^{ER} \cdot E_{isf}^G & \text{if } 1 \leq t \leq T \text{ and } P_s^{ER} \geq P_s^{EW} \text{and } E_{isf}^G \leq E_i^U \\ P_s^{ER} \cdot E_i^U + P_s^{EW} \cdot \left(E_{if}^G - E_i^U\right) & \text{if } 1 \leq t \leq T \text{ and } P_s^{ER} \geq P_s^{EW} \text{ and } E_{isf}^G > E_i^U \end{cases}$$

We assume that net metering laws are in effect and therefore the operation can replace used electricity with generated electricity at the retail rate.

Since the power generation sector is likely to be affected by climate change legislation, we allow the retail and wholesale electricity prices to depend on the carbon intensity of the state energy sources and the price of carbon. Specifically, the retail price of electricity is a function of the observed current retail price P_s^E plus an increase that is proportional to the average carbon dioxide equivalent emissions rate from power plants ϕ_s (in pounds per kW/h) times the carbon price P^M :

$$(2) \qquad P_s^{ER} = P_s^E + 0.00045 \cdot \phi_s \cdot P^M,$$

where we multiply by 0.00045 to convert pounds to metric tons.

The selling price of farm-generated electricity will likely also increase with the carbon price. For simplicity, the selling price of electricity is assumed to be proportional to the retail price:

$$(3) \qquad P_s^{EW} = P_s^{ER} - \theta^W + \eta,$$

where θ^W is the constant difference between the retail and wholesale prices and η is a electricity subsidy parameter that can be varied for policy simulations.

Electricity generation depends on the type of manure storage and the quantity of manure produced. Since the quantity of manure produced is a linear function of the number of head, the quantity of electricity generated can be expressed simply as:

(4) $$E_{if}^{G} = e_{sf} \cdot N_i.$$

For covered lagoon systems, the electricity generated per head, e_{sf}, will depend on climate (characterized at the state level). For plug-flow and complete mix digesters, generation is assumed not to depend on climate because digesters can be heated.

The costs of the biogas system consist of the capital investment K_{if} at the beginning of the project ($t = 0$) plus maintenance and operating costs V_{if} for years 1 through T. Capital investment includes costs of the constructing and designing the pump, pit, heating, building, solids separator, effluent holder, generator, power lines, and so forth. Operations that are in areas in "non-attainment" of the Clean Air Act for ozone face an additional scrubber cost A associated with the electricity generator in the initial year. Allow scrubber costs to be A in non-attainment areas and zero elsewhere. Costs of installing a digester without a generator are modeled as a portion γ of the overall digester-plus-generator costs. Let $\gamma = 1$ for operations that adopt a digester and a generator. A share of capital investment $1 - \lambda$ is born by a government cost-share program such that operators only face the capital cost multiplied by λ. Operating costs are therefore:

(5) $$CD_{ift} = \begin{cases} \lambda\gamma(K_{if} + A) & \text{if } t = 0 \\ \gamma V_{if} & \text{if } 1 \leq t \leq T \end{cases}$$

Since the scrubber costs are only associated with electricity generation, those adopting a digester and flaring the gas would not face potential scrubber costs (i.e., if $\gamma < 1$ then $A = 0$). As operations can obtain subsidies from multiple sources, we do not model a grant cap in this analysis.

Capital investment costs K_{if} increase with the scale of the operation at a decreasing rate that depends on manure-management-type-specific parameters a_f and b_f:

(6) $$K_{if} = a_f \cdot (N_i)^{b_f}$$

Annual variable costs V_{if} include costs of maintenance and repairs. Following past studies, we assume that variable costs are proportional to the quantity of electricity generated (which depends on farm size and type of manure handling facility):

(7) $$V_{if} = v \cdot E_{if}^{G} = v \cdot e_f \cdot N_i.$$

The revenue from selling carbon offsets is dependent on time, the price of carbon, and the amount of methane that can be reduced below the baseline:

(8) $$RO_{isft} = \begin{cases} 0 & \text{if } t = 0 \\ \frac{24}{25} \cdot P^M \cdot M_{isft} & \text{if } 1 \leq t \leq T \end{cases}$$

where P^M is the price of carbon offsets (\$/t CO_2e) and M_{isft} is the quantity of methane produced. Methane has 25 times the global warming capacity of carbon dioxide over 100 years (IPCC, 2007). Burning methane emits 1 ton of CO_2, so burning one ton of methane is equivalent to eliminating 24 tons of carbon dioxide. Thus only $\frac{24}{25}$ of the methane produced could be sold for offset credits.

The quantity of methane produced before installing a digester varies according to manure management method. For operations with anaerobic manure management systems, the quantity of methane produced is:

(9) $$M_{isft} = \begin{cases} 0 & \text{if } t = 0 \\ N_i \cdot m_{sf} \cdot 25 \cdot 365 \cdot 0.001 & \text{if } 1 \leq \text{t} \leq \text{T} \end{cases}$$

where N_i is the number of head and m_{sf} is the methane emission factor (kg CH4 per head per day), which is multiplied by 25 (t CO_2e/t CH_4), 365 (days per year), and 0.001 (tons per kg) in order to express M_{isft} in tons of carbon dioxide equivalents (t CO_2e). For operations with aerobic systems, the amount of methane produced by manure management is assumed to be zero.

Changes in methane produced based on digester installation also vary according to original manure management method. The amount of methane reduced (M_{isft}^R) will be:

$$(10) \qquad M_{isft}^R = \begin{cases} 0 & \text{if } t = 0 \\ \frac{24}{25} \cdot M_{isft} & \text{if } 1 \leq \text{t} \leq \text{T and anaerobic} \\ -N_i \cdot m_{sf} \cdot 365 \cdot 0.001 & \text{if } 1 \leq \text{t} \leq \text{T and aerobic} \end{cases}$$

Transaction costs associated with selling carbon offsets include the initial one-time fixed start-up cost for entering the offset market (Z^E) plus on-going annual costs of monitoring and verification (Z^V):

$$(11) \qquad CO_t = \begin{cases} Z^E & \text{if } t = 0 \\ Z^V & \text{if } 1 \leq t \leq T \end{cases}.$$

Finally, costs of switching from aerobic to anaerobic manure management systems depend on the type of system f and the number of animals N_i; these costs are only incurred in $t = 0$:

$$(12) \qquad W_{ift} = \begin{cases} \lambda(\varpi_f + \pi_f N_i) & \text{if } t = 0 \\ 0 & \text{if } 1 \leq t \leq T \end{cases}.$$

Policy costs

The policy cost for pricing carbon emissions reductions is equal to the discounted total value of offsets, summed over all digester adopters. Allow D_i to be an indicator variable equal to one if the operator i adopts a digester. The policy cost for a per-ton payment for emission reductions is:

(13) $\sum_i D_i \{\sum_{t=0}^{T}[(RO_{isft})/(1+d)^t]\}$

This cost will be borne by the "capped" industries in an emission trading scheme, and the consumers of the products produced by these industries. Or, if the price is a subsidy paid for reducing emissions, the cost will be borne by taxpayers.

The policy cost of subsidizing digester construction will be borne only in the first year, and includes capital, scrubber, and switching costs. Allowing Q_i to be an indicator variable equal to one if the operator i switches from an aerobic to an anaerobic system, policy costs are:

(14) $\sum_i D_i\,(1-\lambda)[\gamma K_{if} + A + Q_i(\varpi_f + \pi_f\, N_i)]$

The policy cost for subsidizing electricity "selling" price will equal the subsdidy rate η multiplied by the amount of electricity sold. Like the value of electricity generated by the digester, the electricity subsidy cost depends on time and on how the quantity generated compares to the quantity used on-farm as well as the retail and selling (subsidized) prices of electricity. For each operator i and time t, the electricity subsidy policy cost GE_{isft} will be:

(15) $$GE_{isft} = \begin{cases} 0 & \text{if } t = 0 \\ \eta E_{isf}^{G} & \text{if } 1 \le t \le T \text{ and } P_s^{ER} < P_s^{EW} \\ 0 & \text{if } 1 \le t \le T \text{ and } P_s^{ER} \ge P_s^{EW} \text{ and } E_{isf}^{G} \le E_i^{U} \\ \eta(E_{isf}^{G} - E_{isf}^{U}) & \text{if } 1 \le t \le T \text{ and } P_s^{ER} \ge P_s^{EW} \text{ and } E_{isf}^{G} > E_i^{U} \end{cases}$$

The total electricity subsidy policy cost will be:

(16) $\sum_i D_i \{\sum_{t=0}^{T}[(GE_{isft})/(1+d)^t]\}$.

If the subsidy is derived from a mandated Renewable Portfolio Standard, the policy cost will be borne by the utility company and electricity consumers.

Social Benefits

Social benefits include the social benefits of renewable electricity and carbon emission reductions. Allow P^{EX} to be the externality cost per kilowatt hour associated with conventionally generated electricity. Since the renewable digester-generated electricity replaces conventionally generated electricity, the social benefit from digester-produced electricity is:

(17) $$\sum_i D_i\left\{\sum_{t=0}^{T}[(P^{EX}E_{if}^{G})/(1+d)^t]\right\}.$$

Allow P^{CX} to be the externality cost per ton of carbon-equivalent emissions. The social benefit from carbon emissions reductions is therefore:

(18) $$\sum_i D_i\left\{\sum_{t=0}^{T}[(P^{CX}M_{isft}^{R})/(1+d)^t]\right\}.$$

The total social benefits will include the total net revenues accruing to digester adopters as well as the social benefits from renewable electricity and carbon.

Caveats

The NPV approach used in this model is deterministic in the sense that real prices are assumed to be known and constant by the operator throughout the economic life of the digester. In fact, many of the benefits and costs associated with a digester are uncertain and variable. For example, the price of electricity – both the retail and selling price – is likely to fluctuate depending on global economic conditions and policy changes that are difficult to predict. Similarly, carbon offset prices have varied dramatically over time, and estimating future carbon prices is difficult. There is also uncertainty about digester variable costs and methane and electrical output, which could fluctuate from year to year depending on system reliability and unexpected weather or mechanical failures.

If we had information about the probability distribution of prices and other model parameters, then it would be possible to estimate the distribution of the NPV, which would provide a more accurate representation of a digester project's value (Leuer, Hyde and Richard, 2008). A further extension could also take into account the irreversible nature of a digester investment. Stokes, Rajagopalan and Stefanou, (2008) use a real option framework to estimate the value to a producer of the option to delay investment in a digester. The authors find that producers would require significant financial compensation – perhaps in the form of assured grant funding or greater electricity prices in order to immediately adopt the technology, rather than delay investment even if the NPV is positive.

By not accounting for the stochastic nature of a digester's benefits and costs nor the option value of delaying investment, we may overestimate the value of digester systems and consequently overestimate digester adoption. However, as noted in the text, we do not account for some possible benefits from a digester such as from "tipping fees" or bedding sales, which reduces our estimate of the project's value. In addition, the study does not account for non-market benefits from a digester such odor control, or reduced water or air pollution, which also causes us to underestimate the private and social benefits of the project. Consideration of these additional factors is beyond the scope of the current research. However, because these concerns are constant across all policy scenarios, the relative effects may be more pertinent.

Data and Parameter Values

To predict digester adoption we utilize data from the 2005 Dairy Production Practices and Costs and Returns Reports, a portion of the Agricultural Resource and Management Surveys (ARMS). The ARMS is a restricted-use dataset compiled by the National Agricultural Statistics Service (NASS) in conjunction with the Economic Research Service (ERS) of the U.S. Department of Agriculture. The unit of analysis in the ARMS data accessed is the farm. For our purposes, the ARMS contains information on the number of head of animals, type of manure management, location of farm, and costs of electricity consumed.

We parameterize our model using information from case studies, government sources, and other documents. Most of these parameters are described in Key and Sneeringer (2011). The additions to this model from prior work focusing only on carbon offset policies include allowing aerobic producers to switch to anaerobic manure management, additional capital costs for producers in areas of Clean Air Act non-attainment, the potential for producers with anaerobic systems to flare methane without converting it to energy, and an adjustment to electricity pricing. For details of these new parameters as well as listings of all parameter values, see Appendix A.

Results

Table 2 illustrates the benefits and costs associated with the three alternative policies when the policy goals are to reduce GHG emissions by 25 percent and 75 percent of baseline levels. These policy goals can be met at the lowest cost with the carbon price (e.g. offset market) policy. GHG reductions 25 percent below the baseline levels can be achieved with an adoption rate of 1% and policy cost equivalent to $6 per ton of CO2e eliminated. For the more ambitious goal of a 75% reduction in carbon emissions, the adoption rate increases to 11% of operations and a policy cost equivalent to $31/tCO2e . It is not surprising that a policy or program that prices carbon emissions is the most efficient of the three policies, since it is the only policy that directly targets GHG emissions reductions.

The cost-share policy is the second most cost-effective policy, achieving the 25% target at a cost of $10/tCO2 compared to $21/tCO2 for the electricity price subsidy. Among the three policies, the cost-share policy induces the highest adoption rates among farmers. For the 75%

target, the cost share induces 64% of operations to adopt compared to 23% for the electricity subsidy and 11% for the carbon price policy.

Part of the reason that the electricity subsidy is the least cost-effective policy for reducing methane emissions is that the high electricity price required to induce sufficient digester adoption provides an incentive for some operations having an aerobic manure management system to convert to an anaerobic systems for the purpose of generating electricity. With the 25% emissions reduction goal, only 3 operations are predicted to convert under the carbon pricing policy compared to nearly 300 under the other two policies. When an operation switches from an aerobic manure system to an anaerobic system the GHG emissions from manure management increase. However, since much of the additional methane produced by the anaerobic manure system is combusted in the process of generating electricity, the net increase is GHG emissions is limited.

Another way of comparing the policy alternatives is to consider their total social net benefits – that is, social benefits gained from reducing emissions and generating electricity, plus the additional profits earned by producers from adopting digesters, less the policy costs. As shown in Table 2, the carbon offset policy has the highest net social benefits at both target levels. In fact, for a 75% reduction in emissions, only the carbon price policy has positive net benefits. While both the cost-share and electricity subsidy policies generate more electricity than the carbon price policy, and the electricity subsidy results in higher profits for the producers than the carbon price policy, the carbon price policy has the lowest cost and consequently the highest net benefits.

Table 3 illustrates the tradeoffs from alternative policies aimed at generating 15 million and 45 million MWh of electricity from digesters over 15 years. The cost-share policy is the most cost-effective, with the lower goal met with a 47% cost share valued at $21/MWh generated and the higher goal met with an 80% cost share equivalent to $61/MWh. The other two policies are substantially more costly.

The cost-share policy is more efficient than the electricity subsidy because the cost-share policy directly targets the policy objective – generating electricity (in the absence of a carbon pricing program that would promote digesters with flares and without generators). In contrast, the electricity price subsidy policy provides an incentive for producers to sell electricity. There are a significant number of producers who find replacing their on-farm electricity with digester-generated electricity profitable, with a relatively low cost share. These same producers would not find it profitable to sell electricity until the selling price were above the retail price, which would require a substantial price subsidy to achieve, and consequently a relatively large program outlay. These different policy effects are reflected by the differences in the adoption rate between the electricity price subsidy and the cost-share programs.

If the objective was to produce electricity that can be sold to the grid and marketed by a utility, then the electricity price subsidy is more efficient than the cost-share policy (Table 4). As mentioned above, the electricity subsidy increases the selling price of electricity which increases the incentive to sell electricity, and only indirectly increases the incentive to produce electricity. In contrast, the cost-share policy lowers the costs of generating electricity, but does not target the selling of electricity. For these reasons the price subsidy achieves the electricity marketing goals more costs-effectively than the cost-share policy.

For the power generation and power sales objectives, the carbon price policy again has the highest net benefits. While carbon price policy meets the policy goals at the highest cost, the policy results in much higher producer profits than the alternative policies and the carbon price policy results in greater GHG reductions.

Table 5 illustrates the outcomes for a policy goal of 10% and 20% of operations adopting a digester. The policy goals are achieved at the lowest cost by the cost-share program. This program is the most efficient because it directly lowers the costs of constructing a digester. For both adoption rate targets, the carbon price policy again has the highest net benefits. The electricity subsidy actually has negative net benefits for both target levels.

Table 6 illustrates the benefits and costs of the three policy approaches given 15-year budgets of $1 billion and $5 billion. With all three policies having identical costs, we find that the cost-share policy would generate the most electricity. For the $1 billion budget, the cost share policy would generate electricity costing $35/MWh compared to $43/MWh for the electricity price subsidy, and $53/MWh for the carbon price policy. In contrast, the carbon price policy reduces GHG emissions most cost-effectively. With the $1 billion budget the carbon policy reduces emissions at a cost of $11/tCO2e, compared to $13/tCO2e for the cost-share, and $19/tCO2e for the electricity price subsidy.

Among the three policies, the carbon price policy achieves the highest net benefits, which also include operator profits. Our estimates indicate that the construction cost-share policy would not result in positive net social benefits if the full $5 billion budget were expended. The reason is that the policy induces a large number of producers to install a digester (the adoption rate is 43%, compared to 12% for the electricity subsidy and carbon price policies). In aggregate, these relatively small-scale producers generate a comparable amount of electricity and reductions in GHG emissions, but they earn, on average, relatively low profits.

One of the most notable aspects with the policy analyses is that the stricter policy objectives imply much higher costs per unit of electricity generated or per unit of GHG emissions reduced. These higher costs, when not accompanied by other benefits, can often result in negative net social benefits for the cost-share and/or the electricity price subsidy policies. However, the carbon offset policy displays positive net benefits under all the policy scenarios considered. Also, for every policy goal except raising the adoption rates (Table 5), the carbon policy achieves higher net benefits under the stricter policy objective. The carbon policy, while generally more costly to achieve the policy objective (except reducing GHG emissions) was efficient at transferring these policy costs to operators, resulting in much higher operator profits.

Finally, we consider how the social net benefits of the alternative policy approaches depend on assumptions about the social benefits of renewable energy and GHG reductions (Table 7). We compare the policy optimal instruments given a $1 billion policy cost over 15 years – that is, the left half of Table 5. We consider two values for benefits of renewable energy: the baseline $0.02/kWh and a higher value of $0.05/kWh, and we consider three values for carbon emission reductions: $0/tCO2e, the baseline $13/tCO2e, and $26/tCO2e.

When renewable energy is valued at $0.02/kWh and no value is placed on carbon emission reductions, none of the projects have a positive net present value. At a higher electricity value ($0.05/kWh), the construction cost subsidy provides the highest net benefits. If GHG emissions are valued at $13 or $26/ton then all projects obtain a positive value, with the policy that prices carbon emissions obtaining greatest benefits at either electricity price. The construction cost subsidy provides a similar but somewhat smaller level of benefits. The electricity price subsidy provides substantially fewer social benefits.

Conclusion

We find that few dairies would need to adopt digesters to meet the relatively modest policy goals of reducing 25% of GHG emissions from dairy manure or generating one million Mwh of electricity per year (or 15 million Mwh over 15 years). Adoption would need to substantially increase for more ambitious policy goals.

The findings demonstrate the importance of matching policy objectives with targeted policy instruments. Reducing GHG emissions from dairy manure management can be achieved most efficiently with a carbon pricing policy (like an offset program), while generating electricity for sale to a grid can be most efficiently done via an energy subsidy. A capital construction cost-sharing program is the most cost-efficient policy for promoting renewable energy generation or for achieving a desired digester adoption rate among producers.

Meeting the less stringent policy goals defined in each category yields positive net social benefits, and these benefits are generally highest for the carbon pricing program. However, meeting some more ambitious policy goals (like a 75% reduction in emissions from dairy manure) yields negative net social benefits for the electricity subsidy and cost share programs. These finding demonstrate the importance of choosing appropriately-scaled policy objectives.

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Table 1. Characteristics of U.S. Dairy Operations

Category	Number of farms in category	Percent of total gross value of production	Percent with lagoon or pit manure system	Percent with lagoon (could also have pit)	Percent of total methane emissions	Electricity use per head (kWh/year)	Electricity price ($/kWh)
All farms	52,237	100%	42%	11%	100%	1,048	0.069
Number of Head							
>2500	248	13.0%	55.6%	48.0%	19.7%	494	0.078
1,000-2,499	917	18.3%	63.5%	38.9%	20.9%	723	0.081
500-999	1,615	14.1%	71.3%	41.5%	18.4%	743	0.079
250-499	3,040	13.5%	72.8%	40.0%	16.0%	775	0.068
<250	46,417	41.1%	38.0%	6.9%	25.0%	1,085	0.068
Region							
West	6,095	33.3%	56.5%	38.1%	43.1%	893	0.058
Midwest	28,438	36.4%	40.2%	5.8%	26.0%	1,102	0.064
South	4,034	9.2%	53.0%	27.1%	15.6%	791	0.065
Northeast	13,670	21.1%	34.3%	3.8%	15.3%	1,080	0.085

Notes: Data from 2005 ARMS Cost of Production Survey for Dairies. All dollar values in real 2009 terms.

Table 2. Policy goal: 25% and 75% reduction in carbon emissions

	25% reduction in carbon emissions			75% reduction in carbon emissions		
	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions
Policy instrument value[a]	0.54	0.070	6	0.91	0.192	31
Digester adoption rate (share of operations)	0.03	0.02	0.01	0.64	0.26	0.11
Electricity generated (mil. MWh)	21	23	12	71	61	32
Electricity sold (mil. MWh)	6	23	3	12	61	7
Carbon emissions reductions (share)	**0.25**	**0.25**	**0.25**	**0.75**	**0.75**	**0.75**
Policy cost (mil. $)	522	1,118	354	6,888	8,475	4,848
Cost per unit electricity ($/MWh)	25	48	31	97	138	150
Cost per carbon reduction ($/tCo2e)	10	21	6	44	54	31
Digester net revenues (mil. $)	219	443	206	1,253	4,336	3,540
Social benefits renewable electricity (mil. $)	286	320	160	985	847	448
Social benefits carbon reductions (mil. $)	677	677	677	2,031	2,031	2,031
Total benefits (mil. $)	1,182	1,439	1,043	4,269	7,214	6,019
Net benefits (mil. $)	661	321	689	-2619	-1260	1170

[a]Policy instrument value refers to 1) construction cost share, 2) electricity subsidy ($/kWh), or 3) carbon price ($/tCO2e).

Notes: Electricity generated and sold are the totals over 15 year life of the project. All monetary values are the net present value for the 15-year project. Social benefits are valued at $0.02/kWh for electricity generated, and $13/tCO2e for carbon emissions reductions.

Table 3. Policy goal: 15 million MWh and 45 million MWh generated

	15 million MWh generated			45 million MWh generated		
	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions
Policy instrument value[a]	0.47	0.050	9	0.80	0.142	56
Digester adoption rate (share of operations)	0.02	0.01	0.02	0.19	0.10	0.20
Electricity generated (mil. MWh)	**15**	**15**	**15**	**45**	**45**	**45**
Electricity sold (mil. MWh)	4	15	4	10	45	10
Carbon emissions reductions (share)	0.19	0.19	0.41	0.58	0.59	0.84
Policy cost (mil. $)	319	524	777	2,745	4,437	9,844
Cost per unit electricity ($/MWh)	21	35	52	61	99	219
Cost per carbon reduction ($/tCo2e)	8	13	9	23	36	56
Digester net revenues (mil. $)	161	174	440	703	2,188	8,040
Social benefits renewable electricity (mil. $)	208	208	208	623	623	623
Social benefits carbon reductions (mil. $)	518	514	1,122	1,573	1,596	2,282
Total benefits (mil. $)	887	895	1769	2,899	4,408	10,945
Net benefits (mil. $)	568	372	992	154	-29	1101

[a]Policy instrument value refers to 1) construction cost share, 2) electricity subsidy ($/kWh), or 3) carbon price ($/tCO2e).

Notes: Electricity generated and sold are the totals over 15 year life of the project. All monetary values are the net present value for the 15-year project. Social benefits are valued at $0.02/kWh for electricity generated, and $13/tCO2e for carbon emissions reductions.

Table 4. Policy goal: 5 million MWh and 10 million MWh sold by dairies

	5 million MWh sold			10 million MWh sold		
	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions
Policy instrument value[a]	0.54	0.032	12	0.82	0.038	58
Digester adoption rate (share of operations)	0.03	0.00	0.03	0.22	0.01	0.21
Electricity generated (mil. MWh)	21	7	20	50	10	46
Electricity sold (mil. MWh)	**5**	**5**	**5**	**10**	**10**	**10**
Carbon emissions reductions (share)	0.26	0.11	0.51	0.61	0.15	0.85
Policy cost (mil. $)	522	150	1,273	3,149	267	10,250
Cost per unit electricity ($/MWh)	25	22	63	63	26	221
Cost per carbon reduction ($/tCo2e)	9	7	12	25	9	58
Digester net revenues (mil. $)	219	35	746	775	70	8,426
Social benefits renewable electricity (mil. $)	286	94	277	694	141	643
Social benefits carbon reductions (mil. $)	717	298	1,379	1,663	398	2,294
Total benefits (mil. $)	1,223	427	2,402	3,132	609	11,363
Net benefits (mil. $)	701	277	1,130	-17	341	1,112

[a]Policy instrument value refers to 1) construction cost share, 2) electricity subsidy ($/kWh), or 3) carbon price ($/tCO2e).

Notes: Electricity generated and sold are the totals over 15 year life of the project. All monetary values are the net present value for the 15-year project. Social benefits are valued at $0.02/kWh for electricity generated, and $13/tCO2e for carbon emissions reductions.

Table 5. Policy goal: 10% and 20% of dairies adopting a digester

	10% of dairies adopt			20% of dairies adopt		
	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions
Policy instrument value[a]	0.74	0.140	28	0.81	0.183	57
Digester adoption rate (share of operations)	**0.10**	**0.10**	**0.10**	**0.20**	**0.20**	**0.20**
Electricity generated (mil. MWh)	38	45	31	48	57	46
Electricity sold (mil. MWh)	9	45	7	10	57	10
Carbon emissions reductions (share)	0.48	0.58	0.74	0.60	0.72	0.84
Policy cost (mil. $)	1,791	4,337	4,297	2,922	7,159	10,041
Cost per unit electricity ($/MWh)	48	97	138	61	127	218
Cost per carbon reduction ($/tCo2e)	18	36	28	23	47	57
Digester net revenues (mil. $)	527	2,126	3,043	738	3,643	8,232
Social benefits renewable electricity (mil. $)	519	620	432	663	782	637
Social benefits carbon reductions (mil. $)	1,309	1,580	1,994	1,633	1,960	2,287
Total benefits (mil. $)	2,355	4,326	5,470	3,034	6,386	11,157
Net benefits (mil. $)	564	-11	1,172	112	-773	1,115

[a]Policy instrument value refers to 1) construction cost share, 2) electricity subsidy ($/kWh), or 3) carbon price ($/tCO2e).

Notes: Electricity generated and sold are the totals over 15 year life of the project. All monetary values are the net present value for the 15-year project. Social benefits are valued at $0.02/kWh for electricity generated, and $13/tCO2e for carbon emissions reductions.

Table 6. Policy goal: $1 billion and $5 billion 15-year policy cost

	$1 billion 15-year policy cost			$5 billion 15-year policy cost		
	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions
Policy instrument value[a]	0.65	0.07	11	0.88	0.16	32
Digester adoption rate (share of operations)	0.05	0.02	0.03	0.43	0.12	0.12
Electricity generated (mil. MWh)	28	22	19	63	48	33
Electricity sold (mil. MWh)	7	22	5	11	48	7
Carbon emissions reductions (share)	0.38	0.25	0.48	0.71	0.62	0.76
Policy cost (mil. $)	**1,000**	**1,000**	**1,000**	**5,000**	**5,000**	**5,000**
Cost per unit electricity ($/MWh)	35	45	53	80	104	152
Cost per carbon reduction ($/tCo2e)	13	19	11	34	39	32
Digester net revenues (mil. $)	352	396	638	1,056	2,480	3,708
Social benefits renewable electricity (mil. $)	394	310	264	869	666	454
Social benefits carbon reductions (mil. $)	1,037	668	1,294	1,926	1,676	2,045
Total benefits (mil. $)	1,782	1,374	2,195	3,852	4,821	6,207
Net benefits (mil. $)	782	374	1,195	-1,148	-179	1,207

[a]Policy instrument value refers to 1) construction cost share, 2) electricity subsidy ($/kWh), or 3) carbon price ($/tCO2e).

Notes: Electricity generated and sold are the totals over 15 year life of the project. All monetary values are the net present value for the 15-year project. Social benefits are valued at $0.02/kWh for electricity generated, and $13/tCO2e for carbon emissions reductions.

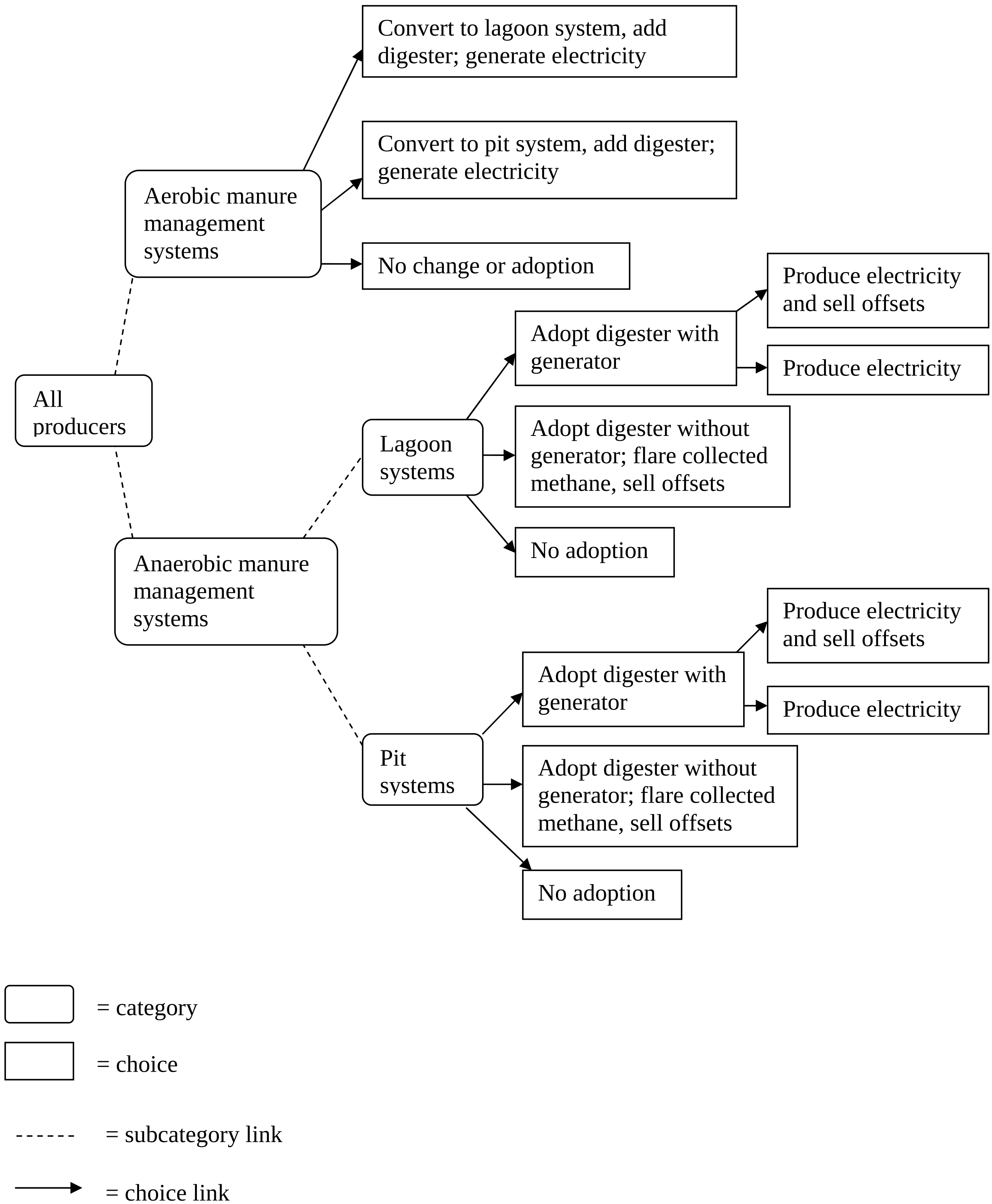
Table 7. Social benefits under alternative benefit assumptions: 15-year policy cost of $1 billion

	Social value of renewable energy = $0.02/kWh			Social value of renewable energy = $0.05/kWh		
	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions	Subsidize construction costs	Subsidize electricity selling price	Price carbon emissions reductions
Policy instrument value[a]	0.65	0.067	11	0.65	0.067	11
Social value of carbon emission reduction = $0/tCO2e						
Social benefits renewable electricity (mil. $)	394	310	264	985	775	659
Social benefits carbon reductions (mil. $)	0	0	0	0	0	0
Total social benefits (mil. $)	746	706	902	1,337	1,171	1,297
Net social benefits (mil. $)	-254	-294	-98	337	171	297
Social value of carbon emission reduction = $13/tCO2e						
Social benefits renewable electricity (mil. $)	394	310	264	985	775	659
Social benefits carbon reductions (mil. $)	1,037	668	1,294	1,037	668	1,294
Total social benefits (mil. $)	1,782	1,374	2,195	2,374	1,839	2,591
Net social benefits (mil. $)	782	374	1,195	1,374	839	1,591
Social value of carbon emission reduction = $26/tCO2e						
Social benefits renewable electricity (mil. $)	394	310	264	985	775	659
Social benefits carbon reductions (mil. $)	2,074	1,336	2,587	2,074	1,336	2,587
Total social benefits (mil. $)	2,819	2,042	3,489	3,411	2,507	3,884
Net social benefits (mil. $)	1,819	1,042	2,489	2,411	1,507	2,884

[a]Policy instrument value refers to 1) construction cost share, 2) electricity subsidy ($/kWh), or 3) carbon price ($/tCO2e).

Notes: Electricity generated and sold are the totals over 15 year life of the project. All monetary values are the net present value for the 15-year project. Social benefits are valued at $0.02/kWh for electricity generated, and $13/tCO2e for carbon emissions reductions.

Fig. 1: Decision to Adopt Digester



Appendix A

Appendix Table A1: Model Parameters, Values, Description, and Sources				
Variable	Value	Units	Description	Source
Estimated parameters				
$e_{f=pit}$	841	kWh/cow	Electricity produced per dairy cow at an operation utilizing a pit-based digester	Averages based on case studies
$e_{f=lagoon}$	$698 \times m_{sf=lagoon}$	kWh/cow	Electricity produced per dairy cow at an operation utilizing a lagoon-based digester	
v	0.033	$/ kWh	Variable cost for dairies	
$a_{f=pit}$	13,712	No unit	Capital investment cost parameter for pit-based digesters	Regression estimates based on case studies
$b_{f=pit}$	0.547	No unit		
$a_{f=lagoon}$	7,391	No unit	Capital investment cost parameter for lagoon-based digesters	
$b_{f=lagoon}$	0.618	No unit		
γ	0.716	%	Percentage of cost of digester plus generator that is just digester	Average based on EPA data
$\varpi_{f=pit}$	13,512	No unit	Manure management method switch cost parameter for pit-based systems	Regression estimates based on NASS data and Fulhage (1997).
$\pi_{f=pit}$	72.82	No unit		
$\varpi_{f=lagoon}$	5,558	No unit	Manure management method switch cost parameter for lagoon-based systems	
$\pi_{f=lagoon}$	48.67	No unit		
P_s^E	Varies by state	$/kWh	State retail electricity price for industrial sector	U.S. EIA, 2010, Table 5.6.B
m_{sf}	Varies by state and manure management method	kg CH4 per head per day	State methane emission factors by manure management method	Chicago Climate Exchange, 2009, Tables 3-4
ϕ_s	Varies by state	lbs/kWh	Carbon emissions factor	US DOE, 2000, Table 4
θ^W	0.031	$	Difference between wholesale and retail prices	US EIA, 2010
Assumed parameters				
d	0.05	rate	Discount rate	
t	15	years	Economic life of a digester	
Z^E	10,000	$	Initial offset market transaction costs	
Z^V	3,000	$	Annual offset market transaction costs	
A	90,000	$	Scrubber cost	
Policy parameters				
P^M	Varies by policy	$/t CO_2e	Price per ton of CO_2e	
η	Varies by policy	$/kWh	Electricity price subsidy	
λ	Varies by policy	%	Percentage of capital costs covered by cost-share program	

Appendix Table A2: Model Variables		
Variable	**Unit**	**Description**
RE_{isft}	$	Value of electricity generated by a digester with a generator
RO_{isft}	$	Value of offset sales
CD_{ift}	$	Cost of digester plus electricity generator
CO_t	$	Cost to sell offsets
W_{ift}	$	Cost to switch from aerobic to anaerobic manure management system
E_{if}^{G}	kWh	Quantity of electricity generated on-farm
E_i^U	kWh	Quantity of electricity used on-farm
P_s^{ER}	$	Retail electricity price
P_s^{EW}	$	Wholesale electricity price
e_{sf}	kWh/head	Electricity generated per head
N_i	head	Number of head
K_{if}	$	Capital investment in digester plus generator
V_{if}	$	Variable costs for digester plus generator
M_{isft}	tCo2e	Quantity of methane produced
M_{isft}^R	tCo2e	Quantity of methane reduced
D_i	No unit	Indicator variable equal to one if operation adopts a digester (with or without a generator)
Q_i	No unit	Indicator variable equal to one if operation switches from aerobic to anaerobic manure system
GE_{isft}	$	Electricity subsidy policy cost for an individual farm

Emissions at lagoon-based facilities
The four case studies with lagoon-based digesters average electricity production of 450kwh per year per head of cattle (see Key and Sneeringer, 2011). These four case studies all arise from California dairies. We adjust the amount of electricity produced according to the emissions factor of the state. California's emission factor for lagoons is 0.645. The amount of electricity that is produced at a dairy with a lagoon-based digester is therefore $450 \times \frac{m_{sf}}{0.645} = 698 \times m_{sf}$.

Generator cost as a percentage of digester plus generator costs
We use EPA data underlying a 2010 report. The EPA collected vendor quotes for 40 digesters; of these, 31 listed costs for a generator. The average percentage of generator plus utility connection costs was 28.4%.

Switching costs
We garner our estimates of switching costs from NASS data and estimates reported in Fulhage (1997). Fulhage reports the costs of installing lagoon and slurry-based manure management systems at dairies (Table 3, p. 1879). These costs are reported in dollars per 45.4kg of milk produced at dairies of 100, 200, 300, 500, and 1,000 head. We first convert these numbers to dollars per head. NASS reports that cows averaged 16,871lb of milk/head in 1997. Using a conversion factor of 0.454 yields about 7,653kg of milk/head. We divide this by 45.4 and then use Fulhage's numbers to generate the cost at each size category reported. We then estimate a

linear regression of number of head on costs to generate our equation for switching costs according to number of head.

Difference between retail and wholesale electricity prices
The average retail price of electricity in the United States (all end uses) in 2008 was 9.8 cents per kilowatt-hour (kWh). The U.S. Energy Information Administration (2010) estimates that on average, distribution and transmission cost 3.1 cents per kWh (generation comprises the remaining 6.7 cents). We therefore allow the difference between the retail and wholesale prices to be 3.1 cents; while retail prices vary by state, this difference between retail and wholesale does not.

Designation of non-attainment counties
Counties that are deemed in "non-attainment" of Clean Air Act standards for certain air pollutants face more stringent regulation than those in attainment. Hence we add an additional cost to operations that would like to adopt a digester with a generator in the non-attainment counties to account for air pollution reduction technology. We specifically use counties that are non-attainment of the 8-hour ozone standard, as listed in the EPA's "Green Book" (Office of the Federal Register, 2009).

References for Appendix

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US Energy Information Administration. 2010. *Annual Energy Outlook 2010*, Reference Case, Table A8: Electrical Supply, Disposition, Prices, and Emissions, p.125 (2010). Accessed at: http://www.eia.gov/oiaf/archive/aeo10/pdf/0383(2010).pdf

US Environmental Protection Agency. 2010. Anaerobic Digestion Capital Costs for Dairy Farms. http://www.epa.gov/agstar/documents/digester_cost_fs.pdf.