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Carbon Prices Required to Make Digesters Profitable on U.S. Dairy Farms of Different Sizes

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Lazarus is a professor and Goodkind is a graduate research assistant in the Department of Applied Economics at the University of Minnesota. Gallagher is a professor in the Department of Economics at Iowa State University. Conway is director with the Office of Energy Policy and New Uses at the U.S. Department of Agriculture (retired).

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Carbon Prices Required to Make Digesters Profitable on U.S. Dairy Farms of Different Sizes

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William F. Lazarus, Andrew Goodkind, Paul Gallagher, Hosein Shapouri, Roger Conway, and James Duffield

Abstract

The objective of this analysis is to evaluate the impacts of three factors: 1) methane emission differences related to climate and manure storage type, 2) digester economies of size, and 3) electricity values on the minimum breakeven carbon dioxide (CO_2) -equivalent methane (CH_4) destruction prices that different-sized dairy farms in different U.S. states would require to make anaerobic digester installation profitable. The number of digesters that would be installed at different prices, and the resulting emission reductions and electrical generation are also estimated. Dairy cows are a significant source of the greenhouse gas methane, so anaerobic digesters are receiving policy attention as a climate change mitigation strategy. Dairy farm methane emissions by state are calculated in this study using the methods used in the U.S. Environmental Protection Agency's annual greenhouse gas inventories. While all of the farms with 2,500-plus cows would install digesters at prices of less than $6 per metric tonne, prices of $39-55 would be required to justify digesters on the 100-199-cow farms. Supply curves are generated empirically for number of digesters, CH_4 emission reductions, and digester-generated electricity as a function of a carbon dioxide (CO_2)-equivalent CH_4 destruction prices ranging from zero to $100/metric tonne. Modeled electricity generation and CH_4 destruction are complementary goods in that higher values on the destroyed CH_4 encourage generation of more electricity. For example, a price of $40 would encourage as many as 4,138 digester installations with 24 teragrams of CO_2-equivalent methane reductions and 468 megawatts of electrical generation. Digester CH_4 destruction revenues may exacerbate consolidation in the dairy industry somewhat because digesters are not financially feasible below around 200 cows in most states. Methane destruction revenues under a $40 CO_2 price will reduce the milk production cost by between $2.19 and $2.83 per 100 kilograms ($0.99 and $1.28 per 100) pounds on farms of 2,500 cows or more. On farms of 200 to 499 cows, CH_4 destruction revenues would have less impact on milk production costs, from 70 cents to $1.32 per 100 kilograms (32 to 60 cents per 100 pounds).

Keywords: anaerobic digester, biogas plant, livestock manure, electricity, methane, carbon offset value

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Introduction

Dairy cows are a significant source of the greenhouse gas methane (CH_4), which has 25 times the global warming potential of carbon dioxide (CO_2) (International Programme on Climate Change, 2007). Methane is emitted by the animals themselves as a result of enteric fermentation. It is also emitted during anaerobic degradation of volatile acids in liquid livestock manure. The nine million mature dairy cows in the U.S. emitted methane (CH_4) equivalent to 64 teragrams (Tg) of CO_2 in enteric fermentation (belching) and manure storage and handling in 2007, or 0.3 percent of total greenhouse gas emissions in the U.S. (USDA National Agricultural Statistics Service, 2008; U.S. Environmental Protection Agency, 2009). This is aside from production of the feed and distribution of the milk they produce and assumes that the CH_4 has 25 times the warming potential of CO_2.

The methane from livestock manure can be captured in an enclosed vessel referred to in the U.S. as an anaerobic digester. The captured gas is referred to as biogas, and is 55-70 percent methane and 30-45 percent carbon dioxide, with small amounts of water and other compounds (Krich et al., 2005). Anaerobic digesters (referred to hereafter as "digesters") destroy methane by combustion, thus minimizing methane emissions. Digesters have multiple benefits for farm profitability. The methane destruction may provide a source of credits that can be marketed to other greenhouse gas emitters who need to offset their own emissions. Such credits, usually measured in terms of CO_2-equivalents, can be a supplemental digester revenue source. The biogas is a source of energy, which at most farm installations is used to generate electricity. The manure solids or fiber can be separated out and used for bedding or as a soil amendment.

The three main types of digesters used on U.S. dairy operations are covered lagoons, plug-flow, and complete-mix or stirred designs. An April, 2010 count of 123 operational dairy digesters shows that plug-flow digesters in various configurations are the most popular design with 73, while there are 27 of the complete mix type, 17 covered lagoons, and 6 of other designs (U.S. AgSTAR, 2010). Other types include fixed-film, induced blanket reactor, and two-phase batch (U.S. AgSTAR, 2010). Lagoon digesters operate at ambient temperatures, while the other two designs are usually insulated and heated to a constant temperature. Since lagoon digesters are unheated, they are best suited for warm climates if maximum energy output is a concern, and 11 of the lagoon digesters are in California while one is in Texas. However, four lagoon digesters are reported in New York and one in Ohio, as well. The Ohio lagoon digester and three of the four New York ones are flaring the biogas rather than using it to generate electricity.

Plug-flow and complete-mix digesters tend to cost more and generate more biogas than lagoon digesters as discussed in more detail below. The costs and performance of plug-flow and complete-mix digesters are similar enough that for the purpose of this study they are combined and referred to as heated digesters while lagoon digesters are treated separately.

Digester penetration is minimal at present in the U.S. dairy industry, with 123 operating compared with a total of 69,890 dairy farms in the U.S. (U.S. AgSTAR, 2010). These digesters add 44 megawatts (MW) of electrical generation capacity to the U.S. total of slightly more than one Terawatt (0.1 percent of the U.S. total). A recent government study found that if 2,600 of the 3,289 large (500+ cows) dairy operations in the U.S. were to install digesters, those systems could potentially provide 359 MW, or five times the present capacity (U.S. AgSTAR, 2006). However, the market incentives required to encourage digester adoption beyond the present 180 are unknown. An increase in the market value of carbon dioxide (CO_2)-equivalent methane destruction offset credits could be an effective incentive for digester installation, but because the U.S. CO_2 marketplace is in its infancy, little information is available on observed CO_2 prices and digester supply response to provide a base for estimation. Instead, a simulation model was used in this analysis to estimate breakeven CO_2 prices above which dairy farms with different characteristics are likely to install additional digesters. The digester supply responses by individual farms are sorted with low-cost farms first and high-cost ones last in order to plot an aggregate supply curve for the U.S. dairy industry. Previous breakeven price threshold studies looked at international transport supply response (Shimojo, 1979); crop residue supply response (Gallagher et al., 2003); and the impact of carbon taxes on global land-based greenhouse gas emissions (Golub et al., 2009).

Farm size and location seem likely to greatly influence the value of a digester to a dairy farm. Methane emissions and related offset credits from livestock manure tend to be greater in warmer climates. Digester economies of size make them more financially attractive for larger operations (U.S. AgSTAR, 2007). The value of digester electricity is likely to vary regionally depending on the fuel mix available to large generators such as public utilities and on state policies. Accordingly, this paper analyzes: 1) methane emission differences related to climate and manure storage type, 2) digester economies of size, and 3) electricity values, in order to project how higher CO_2 prices may increase the number of digesters installed on U.S. dairy farms of different sizes and the resulting emission reductions and electrical generation. The implications for milk production costs by farm size and location are also discussed.

An individual farm breakeven price threshold model is developed in the next section of the paper, followed by a discussion of the data sources for each of the parameters of the model. Supply curves for digester numbers, emission reductions, and electricity generation capacity over the relevant range of CO_2 prices is discussed in the results section of the paper, along with a discussion of the implications for the major dairy producing states and the implications for structural change in the dairy industry. A short concluding section completes the paper.

Research Methods and Data Sources

The breakeven price threshold model describes an individual dairy farm in U.S. state s, with a herd size of n cows and manure storage structure of type m that has not already installed a digester but is now considering one because of the revenue opportunity presented by a policy-induced rise in the price of offset credits. If the farm decides to install a digester, several competing digester designs d are available which vary in cost and potential electricity output $E_{s,d}$. The s subscript on $E_{s,d}$ indicates that electricity output also varies across states due to climate differences, for at least some digester designs. The farm's operator expects the incremental profit from installing a digester of design d to be:

$$Profit_{s,n,m,d} = E_{s,d}R_s + O_{s,m,d}P - C_{s,n,m,d} + L_n$$

where $E_{s,d}$ is electricity generated by the digester system which is either sold or substituted for purchases with value R_s per kWh, $O_{s,d}$ denotes CO_2 offset credits sold at price P. $C_{s,n,m,d}$ is the total annualized ownership and operating cost of a digester of design d in states s, of herd size n, with the farm's existing manure storage type m. L_n represents other considerations such as the value of separated manure solids as bedding, odor control benefits, and risk aversion that are not directly related to climate, electricity value, or digester economies of size. $E_{s,d}$, $O_{s,m,d}$, $C_{s,n,m,d}$ and L_n are expressed as amounts per farm. If digester installation is profitable at any CO_2 price $P_{s,n,m,d}$, there will be a breakeven price (denoted here as $\tilde{P}_{s,n,m,d}$) where the where $Profit_{s,n,m,d}$ exceeds zero for at least one of digester design d. For P below $\tilde{P}_{s,n,m,d}$, by assumption $E_{s,d}$ R_s + $O_{s,d}$ P – $C_{s,m,d}$ + L_n is negative. $\tilde{P}_{s,n,m,d}$ is found by setting $Profit_{s,n,m,d}$ equal to zero and solving for P:

$$\tilde{P}_{s,n,m,d} = \frac{C_{s,n,m,d} - E_{s,d}R_s - L_n}{O_{s,m,d}}$$

In addition to the breakeven point between no digester and first digester installation, there may be other, higher breakeven CO_2 price points where a switch to a more expensive digester with less methane leakage is economically justified as the additional captured methane becomes more valuable.

The interacting impacts of climate differences, digester economies of size, and electricity values on digester adoption were examined by solving the model for each farm size in each state, and for two categories of manure storage systems (anaerobic lagoon or slurry). The model was solved for breakeven prices for an average herd size in each of six farm sizes in each state (1-99, 100-199, 200-499, 500-999, 1,000-2,499, and 2,500 or more dairy cows), which is potentially 48 states x 6 herd sizes x 2 manure storage types or 576 scenarios. Some herd sizes are not found in all states, so the number of scenarios with herd sizes actually reported is 516. The breakeven prices were then sorted from low to high to portray “supply curves” of digester numbers, emissions, and electrical generation capacity as a function of CO_2 price. CO_2 prices up to $100/ton were considered. The data sources for each of the model parameters are described below and summarized in Tables 1 and 2.

Climate-Related Differences in Manure Methane Emissions Among States

Offset credits sold $O_{s,m,d}$ are based on methane emissions from manure storage plus avoided CO_2 emissions from coal-fired electricity replaced by digester electricity minus digester leakage, as described in more detail below. The two main liquid manure storage systems used in the U.S. dairy industry are slurry systems and anaerobic lagoons (U.S. Environmental Protection Agency, 2009). Anaerobic lagoons are usually coupled with flush systems to move the manure from free-stall barn alleys and cow holding areas into the lagoon. Slurry systems use scrapers to move the manure, thus requiring less water. The manure storage structure in a slurry system is designed mainly to store the manure, with little decomposition expected. The EPA assumes that slurry systems are emptied often enough for an average 30-day retention time. Anaerobic lagoons are designed for anaerobic decomposition of the manure so that the nitrogen volatilizes into the atmosphere as ammonia and the phosphorus settles to the bottom as sludge that remains for a number of years before removal (U.S. Environmental Protection Agency, 2002). The EPA assumes that the remaining liquid portion of lagoon manure is removed annually.

Table 1. Dairy Farms, Milk Cow Numbers, Manure System Information, and Digester Electricity Values by State Used in the Model							
	Farms with Milk Cows	Milk Cows	Manure Volatile Solids	Slurry Systems[a]	Anaerobic Lagoons[a]	MCF[b], Slurry Systems	Electricity Value[c]
	number	number	Kg/day/1,000 Kg	%	%	%	$/kWh
California	2,165	1,840,730	9.0	21%	58%	35%	$ 0.116
Idaho	811	536,463	10.3	28%	72%	25%	$ 0.049
Michigan	2,647	344,233	9.1	63%	37%	25%	$ 0.073
Minnesota	5,148	459,752	8.1	71%	29%	25%	$ 0.063
New Mexico	272	326,400	10.0	19%	61%	30%	$ 0.064
New York	5,683	626,455	8.2	64%	36%	23%	$ 0.117
Pennsylvania	8,333	553,321	8.3	74%	26%	26%	$ 0.081
Texas	1,293	404,399	9.2	26%	53%	43%	$ 0.089
Washington	817	243,132	10.5	32%	68%	21%	$ 0.051
Wisconsin	14,158	1,249,309	8.3	70%	30%	24%	$ 0.071
Other states	28,563	2,682,380					
US	69,890	9,266,574	9.1	47%	47%	28%	$ 0.077

[a]The slurry and lagoon system percentages shown are those used for farms with 500 or more cows. The percentages for the smaller farm sizes were varied based on the USDA-NAHMS survey results. The slurry and lagoon percentages total 100 for the northern states, but less than 100 for the southern states due to the use of drylot systems.

[b]Methane conversion factor. 71% is assumed for anaerobic lagoons in all states, based on Lory et al.

[c]The electricity values shown are an average of the 1/09 all-sector average retail prices and estimated large generator avoided costs, assuming that half of the electricity replaces purchases and half is sold.

Table 2. Parameters Specified in the Model

Parameter	Units	Value	Data Source(s)
Dairy farms and cow numbers by size	Number	Varies by state and size category	U.S. Census of Agriculture
Volatile manure solids excreted (VS)	kg./day/1,000 kg. of animal weight	Varies by state, from 6.88 in LA to 11.03 in AZ.	U.S. EPA 2009
Maximum CH_4 producing capacity (B_0)	m^3 CH_4/kg. VS	0.24	U.S. EPA 2009
Manure storage system	Percent of farms	Lagoon or slurry, varies by state and herd size. For example, on 2,500+ cow farms, slurry systems varied from 15% in FL to 80% in KY. Lagoons varied from 20% in KY to 72% in ID.	U.S. EPA 2009, USDA NAHMS 2009
Methane conversion factor for non-digester emissions (MCF)	Percent of B_0	Varies by state and manure storage system. Slurry systems vary from 16% in MT to 44% in FL. Lagoons assumed 71% for all states.	U.S. EPA 2009
Digester management factor	Percent of B_0	90%	U.S. EPA 2009
Digester methane collection efficiency	Percent	99% for heated digesters, 75% for lagoon digesters	U.S. EPA 2009
Digester methane destruction efficiency	Percent	98%	U.S. EPA 2009
Digester engine thermal conversion efficiency	Percent	25%	Gooch 2009, slide 43
Digester capital investment	2008 dollars	Heated digester, electricity: $626,018+$714/cow Lagoon or heated digester, flare: $373,773+$426/cow Lagoon digester, electricity: $575,154+$656/cow Cover existing lagoon: flare - $208,464+$238/cow elec - $409,885 + $467/cow Lagoon costs increased for northern states. Engine investment increased in CA due to NOx controls.	Crenshaw, U.S. AgSTAR 2009, Beddoes et al. 2007, Huffstutter 2010

Table 2 (continued)

Digester operation and maintenance expenses	Percent of total digester initial investment	3% for digesters with electrical generation, 0.9% without electrical generation, increased in CA due to NOx controls.	Martin 2004, Huffstutter 2010
Opportunity cost (interest rate) on digester investment	Percent	6%	Federal Reserve Bank of Minneapolis 2009
Digester useful life	Years	20	Assumed
Electricity retail rate, all sectors	cents/kWh	Varies by state, from 5.1 in ID to 15.7 in CT.	U.S. EIA 2009
Large generator electricity fuel, O&M, and capital cost	cents/kWh	Natural gas 9.6 Petroleum 7.6 Nuclear 9.2 Hydroelectric 2.0 Coal 0.3 + fuel. Total cost varies from 2.6 in WA to 9.5 in NY.	Prices from U.S. EIA 2009 Coal BTU/pound from U.S. EIA 1999
Solids value for bedding, risk aversion, and other factors	$/cow	$10	Assumed, based on CFFM data, undated (Minnesota dairy farms averaged $50 expense for bedding)

In cooler climates, the manure degradation process slows or stops during the winter so a lagoon must be larger to achieve the planned level of annual treatment during just the warm months. The larger lagoon size increases the cost $C_{s,n,m,d}$ for lagoon digesters in northern states, while heated digester costs are expected to be constant across states. Also, flush systems are less desirable in cool climates because the water can freeze in cold weather, so scraper systems are more common and contribute to the popularity of slurry systems.

Dairy farm methane emissions by state are calculated annually by the U.S. Environmental Protection Agency (U.S. Environmental Protection Agency, 2009). For farms without digesters, methane emissions/cow are calculated as VS * B_o * MCF, where VS is the manure volatile solids excretion rate. Manure solids include a portion that is readily broken down by bacteria and emits methane. This portion is referred to in the literature as volatile and is what is relevant here. The remaining solids are more stable and are eventually applied to cropland. B_o indicates the maximum methane generation potential, and is 0.24 cubic meters of methane / kilogram of VS for dairy cows. Volatile solids vary by state based mainly on milk production levels. Not all of the volatile solids are actually converted during storage, therefore B_o alone would over-estimate methane production. The bacterial activity required for conversion slows or stops during the winter in northern states. The methane conversion factor, MCF, is a percentage that varies by manure storage type and by state due to climate differences. The EPA uses the van't Hoff-Arrhenius equation to estimate MCFs by state for anaerobic lagoons and liquid/slurry systems. The MCFs for slurry systems are lower than for anaerobic lagoons because of the one-month retention time assumed for slurry systems compared to up to five months for lagoons. The climate-related variation in MCF means that, for example, the MCFs for slurry systems are 25 percent for Minnesota and 35 percent for California.

The EPA has estimated MCFs for lagoons of 68 percent for Minnesota and 74 percent for California, but a recent analysis asserts that the EPA's lagoon calculations are flawed because they neglect to account for the fact that current lagoon design standards compensate for temperature effects on the degradation capacity of a lagoon by increasing the size of the treatment volume in more northerly climates by increasing the size of the treatment volume in more northerly climates (Lory et al., 2010). The EPA's slurry system MCFs were not questioned in that study. Lory et al. find that methane emissions from dairy facilities may be more than 130 percent more than estimated using the EPA's MCFs. However, Lory et al. also cite three studies with direct measurements of methane emissions from swine lagoons, and those three studies found the emissions to be lower than both the EPA's MCFs and Lory et al.'s modified approach predicted. In light of Lory et al.'s argument that lagoon emissions should not vary by climate and this unsettled state of knowledge about the absolute level of lagoon emissions, for the purpose of this analysis we assume for all states an MCF of 71 percent, which is the simple average of the EPA's individual state lagoon MCFs. For slurry systems, we use the EPA's climate-varying individual state MCFs.

Dairy farms of different sizes and in different localities tend to use different manure systems. In Minnesota, for example, the EPA estimates that 24 percent of dairy farms have slurry systems and 12 percent have anaerobic lagoons (see Table A-172 on page A-205 of the 2009 EPA inventory). The most common manure storage system in Minnesota is solid storage, at 44 percent. In California 58 percent have lagoons, 21 percent slurry systems, and 9 percent solid storage. The remaining farms are on pastures, or utilize daily spreading or deep pit manure management systems.

Dairy management practice surveys by the USDA National Animal Health Monitoring System (NAHMS) contain a limited amount of information on differences in manure storage systems by farm size and region (USDA National Animal Health Monitoring System, 2009). Almost all large farms handled at least some of their manure in liquid form, with only 0.2 percent using a solid system only. Of farms with 100-499 cows, 75 percent used both liquid and solid systems, with 48 percent of farms of fewer than 100 cows using both systems. No farms reported using only a liquid manure system. The NAHMS data does not show how much of the manure is liquid versus solid on the farms using both systems, but it is likely that most of the manure on these farms is generated by the milking herd in free stall barns and is handled as a liquid. Dry cows are sometimes housed in a separate facility where the manure is handled as a solid. Hence, the liquid manure system would be the predominant system on these farms. Based on the NAHMS data, here all of the farms with 500 or more cows are assumed to use a liquid manure system except for the southwestern states of Arizona, California, Nevada, New Mexico, and Texas along with the southern state of Florida where open drylots are common for large dairies. The EPA slurry and deep pit categories are combined in our analysis. The percentages of slurry/deep pit versus lagoon were taken from the EPA percentages of these two categories divided by the total of the two. For the southwestern and southern states, the EPA proportions were used as is.

Digester Efficiency Impacts on Available Offset Amounts

When a heated digester is installed to reduce methane emissions from manure, methane production generally increases compared to emissions from a non-digester manure storage system due to optimization of the digester operating temperature. An important principle of greenhouse gas credit accounting is that credits should be based on a reduction in emissions compared to some baseline. In the present analysis, the baseline is assumed to be emissions from a given scenario of state, farm size, and manure system as reflected in the VS, Bo, and MCF parameters discussed above. The EPA calculations model methane emissions in digesters by replacing MCF with a management factor assumed to be 90 percent. Some of the digester methane leaks out and contributes to emissions, however. Supporting documentation for recent EPA greenhouse gas inventory reports assume that mixed and plug-flow digesters collect 99 percent of the methane while covered lagoons collect 75 percent (U.S. Environmental Protection Agency, 2009). The source of the 75 percent figure is not documented in that source document, but they relate the collection efficiency to the percentage of the lagoon surface covered in a separate draft protocol for calculating greenhouse gas offsets for digester projects (Climate Protection Partnerships Division, Climate Change Division Office of Atmospheric Programs, U.S. Environmental Protection Agency, 2008). That document suggests using 95-99 percent for impermeable bank-to-bank covers and 50-90 percent for impermeable, modular covers.

Without knowing which type of covers dairy producers might install in the future in response to higher CO_2 prices, another approach is used here to verify the reasonableness of the 75 percent versus 99 percent collection efficiencies are for lagoon versus heated digesters. Our approach is to regress installed electrical generation capacities on the dairy populations feeding the digester for 96 operational dairy farm digesters in the Agstar database, with (0,1) variables for digester type (covered lagoon or other), and for co-digestion with other feedstocks (1 = co-digestion, 0 otherwise). The resulting equation is:

$$
\begin{array}{llll}
kW = & 0.261 * pop & - 0.091 * pop * CL & - 0.072 * pop * CoD \\
 & (0.0164) & (0.0419) & (0.0238)
\end{array}
$$

where kW is the installed electrical generation capacity in kW, pop is the dairy population feeding the digester, CL is 1 if a covered lagoon digester and 0 if another type, and CoD is 1 if co-digesting with other feedstocks. The coefficients on all three variables are significant at the five percent level as indicated by the standard errors shown in the parentheses. The adjusted R^2 is 0.78. In other specifications of the model, the intercept and (0,1) variables for digester type and for co-digestion were not significant and were dropped. The results indicate that estimated installed capacity for covered lagoon digesters is 0.261 – 0.091 = 0.170 kW per cow, when not co-digesting. This is 72 percent of the 0.261 kW per cow for other digester types, which is a little less than but “close” to the 75 / 99 = 76 percent difference in collection efficiency that the EPA greenhouse gas inventory reports assume. So, the EPA’s 75 and 99 percent collection efficiencies are used here.

An interesting side issue is that the coefficient on the co-digestion variable is negative, despite the fact that co-digestion (adding feedstocks other than manure) would normally be expected to increase biogas output which could be used to generate more electricity than would otherwise be possible. Co-digestion economics is beyond the scope of the present analysis, so that issue is not pursued further here.

The EPA inventory assumes that the collected methane is destroyed with 98 percent efficiency for all digesters. Based on those parameters, the methane available for electricity generation/cow is then VS *B_o * CE * DE, where CE is collection efficiency and DE is destruction efficiency. Methane that is generated but escapes is: VS * B_o *[(1 – CE) + CE *(1 – DE)]. In the case of mixed and plug-flow digesters, a CE of 99 percent and DE of 98 percent imply leakage of [(1 – 0.99) + 0.99 *(1 – 0.98)] or 2.98 percent. In the case of a lagoon digester, a CE of 75 percent means that [(1 – 0.75) + 0.75 *(1 – 0.02)] or 26.5 percent of the digester methane would leak. This leakage reduces the amount of credit that is based on emissions that would occur without the digester. Thus, the credit amount is equal to the baseline non-digester emissions minus the digester leakage.

The higher collection efficiency of a plug-flow or mixed digester gives these designs an advantage in potential credits. The methane reduction with a heated digester in California, for example, would be 50 percent higher than with a lagoon digester.

Digester Economies of Size, Investment Requirement, Operating Costs, and Public Incentives

The digester vessel alternatives of heated versus covered lagoon plus the choice of just flaring the biogas or generating electricity result in four digester designs to consider: 1) unheated lagoon with flare only, 2) unheated lagoon with electricity generation, 3) heated digester with flare, and 4) heated digester with electricity generation. Heated digesters generate more biogas and potentially more electricity, especially in northern climates.

Regressions of installation cost on herd size for sixteen recent dairy farm plug-flow digesters and ten mixed digesters with electricity generation showed a smaller intercept but a steeper slope for the mixed type

(Crenshaw, 2009; U.S. AgSTAR, 2009a). The regressions suggest a mixed digester cost that is 78 percent of the plug-flow cost at 1,000 cows, with the difference narrowing to 91 percent of the plug-flow cost at 2,500 cows. The lower cost for the mixed design is interesting in that the plug-flow design was originally developed as a lower-cost alternative to mixed digesters (Lusk, 1998). Given the small sample sizes and the Lusk report's information about the two designs, for our purposes the results were averaged to yield an equation for heated digesters of \$516,465 + \$589/cow. Adding the ancillary costs for connecting to the utility grid, removing hydrogen sulfide, and separating solids increases the coefficients to \$626,018 + \$714/cow. Results for two example herd sizes are then \$1.1 million for a 700-cow dairy operation and \$2.6 million for 2,800 cows.

The Crenshaw equations include electrical generation equipment, which amounted to 36 percent of the total investment on average at 38 earlier digester installations (Beddoes et al., 2007). Netting out that portion of the investment but including Crenshaw's cost for a solids separator results in an equation for flare-only digesters of total cost = \$373,733 + \$426/cow.

Crenshaw had data on only two covered lagoon digesters, so he did not develop a regression equation for this design. The reported costs for those two lagoon digesters averaged 8 percent less than the costs predicted by the above equation for the same herd sizes. One reason for a lagoon digester's lower cost is that the reduced collection efficiency means less methane to supply the electrical generation equipment, which could then be reduced in size. Based on the Beddoes et al. percentage and the CE difference, the difference in engine size accounts for [0.36 * (1 – 0.75/0.99)] or 8.7 percent, which is close to the 8 percent difference actually reported by Crenshaw. Based on that logic, lagoon digesters without electricity generation are assumed to cost the same as heated digesters while the electrical generation cost is reduced by the difference in collection efficiency, so that the total cost of a lagoon digester with electricity in a southern state is 8.7 percent less than a heated digester.

Lagoon volatile solids loading rates are reduced when lagoons are used in cooler climates, by increasing the lagoon size for a given herd size (see map on page 5-33 of (U.S. Environmental Protection Agency, 2002)). The lagoon equations discussed above are used for California and North Carolina, two states where lagoons are common. The lagoon sizes and costs for more northern states are increased based on a set of multipliers derived from the above map, so that a lagoon in Minnesota, for example, costs 71 percent more than in California. The electrical equipment and other components were not varied by state.

While digesters are considered beneficial in terms of methane destruction, the internal combustion digester engines commonly used to generate electricity emit other air pollutants, of which nitrogen oxides (NOx) are particularly problematic to control. Proposed federal limits on digester NOx emissions are 2 grams per horsepower-hour starting in 2011 (U.S. Environmental Protection Agency, 2006). It is not clear how much the tightening NOx limits will increase digester capital and operating costs. California has tighter air quality standards than the rest of the U.S., and the cost of meeting those standards has cost some digesters there to shut down. For example, the 2,513-cow Fiscalini Farms digester in the San Joaquin Valley was required to meet a NOx standard of 9 parts per million (ppm) (San Joaquin Valley Air Pollution Control District, 2007; U.S. AgSTAR, 2010). Goodrich reported a 2,960 ppm emission level for a 135-horsepower digester engine and stated that it was equivalent to 25.5 grams/kWh, or 116 ppmv per gram/horsepower-hour. At that conversion rate, the 9-ppm California standard is equivalent to around 0.08 grams/horsepower and is far less than the federal 2-gram limit (Goodrich et al., 2008).

A California catalytic converter and other filtering equipment cost “several hundreds of thousands of dollars” for the Fiscalini digester (Huffstutter, 2010). The 2,000-cow Koetsier Dairy in Visalia, California shut down rather than invest $100,000 for parts and spend $50,000 per year in maintenance fees to control NOx from its 135-kW engine. The quoted fees amount to an added investment of $50/cow and O&M of $25/cow/year, or an investment of $740/kW and $370/kW/year for O&M (U.S. AgSTAR, 2010). The $100,000 added investment is somewhat lower than the “several hundreds of thousands of dollars” reported by Fiscalini for a larger herd. The O&M cost is more significant than the added investment, amounting to around 4.6 cents/kWh if operating 90 percent of the time. The rate of digester installations appears to have slowed down in California recently, with only one becoming operational in 2009 compared with five in 2008, perhaps due to the NOx issue (U.S. AgSTAR, 2010). For the purpose of the present analysis, the Crenshaw investment estimates were used for all states except California, to which was added the extra $50/kW investment and $370/kW/year in O&M to meet the tougher California NOx standard. As engine designs are improved over time for better NOx control and as the tighter federal regulations affect the rest of the country, the California cost disadvantage may be minimized – it is too soon to tell how quickly or to what extent this may happen, so the differential is incorporated in the present model as described above.

If the EPA’s estimate of 75 percent collection efficiency is accurate for lagoon digesters, then for any dairy producer to find it profitable to install a lagoon digester rather than the heated type, the lagoon digester would need to be enough cheaper than the heated type to offset the difference in gas collection efficiency. Eleven of the 17 digesters in California are covered lagoons, suggesting that lagoon digesters have tended to be more cost-effective under California conditions than suggested by the Crenshaw differential. The Crenshaw numbers for heated digesters are used in the present analysis due to the lack of more detailed information on the California situation. As it turns out, the added investment and O&M cost for NOx control are enough to make additional digesters of either type unprofitable California, so the question of the cost differential between the two designs becomes largely moot. The results are a better fit with the rest of the U.S., where only six of the 107 operational digesters are covered lagoons with the rest being the heated type.

Since digester engine-generator sets operate continuously, the engines typically require major overhauls every 3-5 years depending on the quality of maintenance and whether gas cleanup equipment is installed. Flexible covers, pumps, and other components will likely require periodic replacement. The digester vessel itself may also require periodic cleanouts to remove sludge. Expenses for the operation of a digester with electrical generation is assumed to be 3 percent of the initial investment/year{Martin 2007 #10960}.

No information is available on operating costs for a digester without electrical generation equipment. It is expected to be significantly less because the large expense of engine overhauls is avoided, although the other items mentioned above would still be incurred. In the absence of other information, it is assumed that 80 percent of the 3 percent is related to the engine and generator. Subtracting that 80 percent portion of the operating cost and subtracting the generation equipment from the investment implies an O&M rate of 0.9 percent of the investment without electricity generation.

Most digester installations that have been described in the literature recently have also received public incentives of various kinds. One significant incentive is the USDA Rural Energy for America Program (REAP) which provides grants of up to 25 percent and guaranteed loans of up to 50 percent of project costs (Rural Development, USDA, undated). Around half of the digesters received REAP assistance in recent years (Thompson & Voell, 2009). REAP funding is $60 million in 2010, increasing to $70 million in 2011 and 2012 (North Carolina Solar Center, 2007). Digesters are only one of a number of renewable energy technologies eligible for this funding, however. Digesters received $40 million of REAP funding since 2003 (U.S. AgSTAR, 2009b). For the purposes of the present study, a question is how much REAP funding will be available for digesters in the future if an increase in the carbon price were to set off a sharp increase in digester installations. Lacking a definitive answer to that question, here it is assumed that another $60 million in REAP grants will be made available to the first digesters installed, after which REAP funding runs out and later digesters would be funded from private capital sources.

Many states and some electrical utilities offer incentives to assist with investment requirements and operating costs of digesters. The Database of State Incentives for Renewables and Efficiency (DSIRE) tracks these incentives (North Carolina Solar Center, 2007). However, it is unknown how far these state and utility funds would go if higher carbon prices caused digester installation to increase substantially in the future, so they are omitted from this analysis. The breakeven carbon prices presented here should thus be viewed as conservative in that such incentives could make digesters profitable below those prices. The breakeven carbon prices presented here should thus be viewed as conservative in that such incentives could make digesters profitable below those prices.

Annual Capital Costs and Cost Recovery Factors

The time value of the money invested in the digester system is accounted for by assuming an interest rate of 6 percent, near current U.S. rates for agricultural loans (Federal Reserve Bank of Minneapolis, undated). The useful life of the system is projected to be 20 years, so that the investment is annualized over at life by applying a cost recovery factor of $0.06/[1-1/(1+0.06)^{20}]$ or 8.7 percent to convert the investment to an annual capital cost. Reducing the investment by the amount of a 25 percent REAP grant reduces the annual capital cost to 8.7 percent * (1 – 0.25) or 6.5 percent of the before-grant investment. The total of the 6.5 percent capital cost plus 5 percent operating cost is then 11.5 percent percent/year for a digester with electricity generation, or 6.5 percent plus 1.6 percent operating or 8.1 percent total without electricity.

Electricity Value Differences Across States

If the electrical generation equipment is installed, the electricity provides value in terms of avoided electricity purchases and/or excess sales that vary with the level of methane emissions, the electricity price, and renewable electricity credits (RECs) for reduced fossil-fuel electricity that the digester electricity replaces. The electricity generated can offset farm electricity use with the excess sold back to the utility grid, but generally at a lower price related to the utility's avoided generation cost for conventional fossil fuels and nuclear and hydroelectric sources utilized in large generation facilities. Avoided use is generally worth the retail electricity price, less demand or capacity charges which can be significant. This regional variation in digester electricity value is not reported publicly except for anecdotal reports in various digester case studies. For the purpose of this analysis, the value of digester electricity is estimated from public information on state-level retail electricity prices and electrical generation costs from conventional fossil fuels and nuclear and hydroelectric sources. Three recent dairy digester case studies provide information on the percentage of the electricity that offsets farm use versus being sold as excess. Martin reported that 67 percent offset farm use at a New York digester (Martin, 2004). Lazarus and Rudstrom reported 60 percent offsetting farm use for a Minnesota digester (Lazarus & Rudstrom, 2007). Bishop and Shumway did not report percentages, but the $0.035/kWh price they reported for 2007 for a Washington State digester is close to the generation cost in that state as estimated below, suggesting that their negotiated power purchase agreement treated all or nearly all of the electricity as excess sales (Bishop & Shumway, 2009). Given that variation, the electricity is valued in this analysis at the average of the retail price and the utility's large producer generation cost.

All-sector electricity retail prices from the U.S. Energy Information Administration (EIA) for January 2009 were used to be consistent with the most recent data available for fuel prices (U.S. Energy Information Administration, 2010). The electrical generation cost avoided by the large generators in each state is estimated from conventional fuel costs for fossil fuels (coal, petroleum, and natural gas) and nuclear and hydroelectric sources, and power plant capital and operating costs, and state average retail rates. The retail electricity rates are assumed to cover three categories of utility costs: generation, transmission, and distribution. The interest here is in the generation costs, because they are the main costs the utilities can avoid by purchasing electricity from a distributed source such as a digester.

The generation cost/kilowatt-hour (kWh) was estimated based on fuel costs, operating expenses, and estimated capital costs. These costs differed among the five fuels but were the same for all states for a given fuel, except for a quality adjustment to the coal price that varied by state. A weighted average estimated generation cost was calculated for the five fuels, weighted by the percentage each made up of the five-fuel total for each state. The five fuels discussed above generated 97 percent of total U.S. electricity, with all states over 90 percent except for Maine at 72 percent and California at 87 percent. Maine was reported as using wood and wood-derived fuels for 24 percent of its power. The EIA does not report a fuel cost for nuclear plants, so the amount reported by Xcel Energy for its Northern States Power plants is used ($0.00579/kWh). The EIA reports coal prices/ton by state, which were adjusted based on differences in heating value between eastern and western coal (U.S. Energy Information Administration, 1999).

Power plant capital cost recovery amounts were based on the investment requirement/kilowatt (KW) of generating capacity for new electricity generating technologies estimated by the EIA. A conventional combustion turbine was assumed for coal and a conventional gas/oil combined cycle technology was assumed for petroleum and natural gas (U.S. Energy Information Administration, 2009). The EIA estimated investment amounts were annualized using the U.S. Internal Revenue Service depreciation class life for each type of power plant and a 3.9 percent after-tax opportunity cost interest rate. The interest rate was based on Xcel Energy's 2008 interest charges and financing costs and the 35 percent federal corporate income tax rate.

The estimated large producer generation costs averaged 6.0 cents/kWh for the U.S. The retail price averaged 9.7 cents/kWh across all sectors, implying a 3.7-cent transmission and distribution differential. Generation costs ranged from 3.3 cents in Washington to 8.0 cents in the New York.

CO_2 and REC Values

Carbon dioxide offset values in the U.S. peaked at over $7 per metric tonne in mid-2008 but have since fallen to near zero (Chicago Climate Exchange, 2009). Prices on the European Climate Exchange might be more indicative of future U.S. prices under a cap-and-trade system because Europe already has such a system. Prices on that exchange in December 2009 were around 13 euros per metric tonne, which is $19.50 per metric tonne at an exchange rate of $1.50 per euro (European Climate Exchange, 2009; Wall Street Journal, 2009). Another source of projected future CO_2 prices is an April 2008 analysis of U.S. Senate bill S. 2191, the Lieberman-Warner Climate Security Act of 2007, by the U.S. Energy Information Administration. That bill, which did not pass, would have established a cap on emissions of greenhouse gases beginning in 2012 through an emission allowance program. The core scenario in that analysis was that a 27 percent reduction in greenhouse gas emissions by 2020 would be accompanied by a CO_2 price of $30 and that a 50 percent reduction by 2030 would be accompanied by a price of $61. In the most extreme case examined, assuming that the use of international offsets and key technologies such as nuclear and fossil fuel electricity generation with carbon capture and sequestration are limited, the CO_2 price could go as high as $156 (U.S. Energy Information Administration, 2008). Three other recent Congressional proposals would have resulted in CO_2 prices of $13, $60, and $374 per metric tonne by 2050 (Metcalf et al., 2008). While some of these projections are for quite high carbon prices, the fact that the Lieberman-Warner bill was voted down in Congress suggests that prices at the high end of these projections may not be politically feasible in the near term. For that reason, this analysis considered a range of zero to $100. To arrive at a “most-likely” price that was used to calculate the impact on milk production costs, the current $19.41 European Climate Exchange price was rounded up to $20 U.S. A $40 price was also evaluated because it is in the range of the prices projected to occur between 2020 and 2030 under the Lieberman-Warner bill.

A related revenue source is a REC for electricity generated by a digester or other renewable energy source that can help public utilities meet renewable electricity portfolio standards that have been imposed by 29 states and the District of Columbia (North Carolina Solar Center, 2007). A 2008 New York study found that REC prices varied depending on vintage, delivery requirements, and technology eligibility from $15 to $55/mWh in the northeastern states, to as low as $4.25/mWh in Texas where the price was thought to be depressed because of abundant wind energy. The most recent REC solicitation in New York was in March of

2010, and resulted in an average price of \$21/mWh (Rose, 2010). In the Midwest, however, the large number of wind farms under development has driven REC prices to \$1 per mWh in early 2010 from \$6 to \$10/mWh a year or two earlier (Gruenness, 2010; Rathburn, 2010). Each \$1 REC is equivalent to a CO_2 price of \$1 per mt of CO_2 if the digester electricity replaces coal that emits 1 kg of CO_2 per kWh. A REC is thought to represent avoided emissions of greenhouse gases but also other pollutants such as SOx, NOx and CO as well as other motivations for implementing renewable portfolio standards (Stern et al., 2009). So, it is not surprising that current REC prices exceed the current near-zero CO_2 prices in the voluntary U.S. carbon market. However, if a policy change increases CO_2 prices in the U.S., increased installations of digesters and other renewable energy technologies could exceed the state renewable electricity portfolio standards in other states as wind farms have already done in the Midwest, which could drive REC values down to their CO_2 values. For the purpose of calculating the breakeven CO_2 prices in this study, it is assumed that other components of the REC value of digester electricity would in fact quickly dissipate if the CO_2 price rises. Accordingly, the REC prices are scaled proportionately with the CO_2 price. If the other components were to remain a significant digester revenue source, the breakeven CO_2 price could be lower than those presented here.

Bedding Value, Odor Control Benefits, and Risk Aversion

Little information is available on the magnitude of the parameter L_n representing other considerations such as the value of separated manure solids as bedding, odor control benefits, and risk aversion that are not directly related to climate, electricity value, or digester economies of size. Many digesters are also coupled with solids separators that supply fiber that can be used for bedding or sold as a soil amendment. These separated manure solids are generally regarded as another important source of value, but arriving at a specific value for the solids is difficult. Wood shavings for bedding are also in short supply in some areas. Dairy farms in Minnesota spent \$50/cow on bedding in 2007 (Center for Farm Financial Management, University of Minnesota, undated). Many dairy farms use sand as bedding, and must switch to an alternative bedding source when installing a digester because the sand would plug up the digester. Bedding with manure solids requires careful management to minimize bacteria buildup that might contribute to mastitis problems in the dairy herd. In such situations where shift from sand to manure solids is forced by the presence of the digester and possibly increases mastitis problems, the dairy producer may not place much value on the solids.

Other factors represented in L_n are tipping fees for accepting offsite food processing wastes, which have also contributed significant value for a few digesters, and odor control which has also been an important motivation for many digesters but is difficult to value in financial terms.

While we do not know the value of L_n for U.S. dairy farms, we do know that the considerations reflected in L along with CO_2 prices in the \$0-7 range have encouraged a few U.S. dairy farms (123) to install digesters already. Hence, since the purpose of this study is to quantify how a CO_2 price greater than zero might encourage additional digesters beyond the present 123, L_n is set to a value such that $Profit_{s,n,m,d}$ is positive for approximately 123 farms with the most favorable electricity rates, offset amounts, and costs; and negative for those in less favorable situations. The \$10/cow value is used to generate the results discussed below.

Results and Discussion

The derivation of technical yields that define electricity generation and CO_2 credits are given in Table 3. The range of technical tradeoffs and financial outcomes associated with digester adoption are illustrated in Table 4 for a 4,000-cow Texas dairy farm and a 500-cow Minnesota dairy farm. We consider a carbon credit or tax of \$20/mt CO_2 along with a 25 percent REAP grant at both locations – carbon incentives of this magnitude have been discussed with recent US legislation. Finally, electricity prices are an average of retail prices and production costs of large electricity producers – about half of digester output can displace on-farm use and half can be resold to the grid. The difference in CO_2 reductions, electricity generation, and per-cow investment combine to make the digester look quite profitable on the Texas dairy ($144/cow) but unprofitable in Minnesota ($-64/cow).

Wisconsin, New York, California, and Pennsylvania are the states with the most operational dairy farm digesters, with over ten each out of the 123 digesters in the U.S. (Table 5). The model projects that with a zero CO_2 price, REAP grants covering 25 percent of the investment, and other parameters as described in Tables 1 and 2, it would be profitable to install 147 digesters in the U.S. (Table 6, top panel). Because of the model's simplistic design of ignoring cost and performance variability among the farms in a given state, size, and manure system category, the projected geographic pattern in Table 6 for a zero CO_2 price does not match the actual geographic pattern well. Of the major dairy states, the model projection is that New York and Texas install at the zero price along with New Hampshire and Vermont because of relatively high electricity values, while California, Pennsylvania, and Wisconsin do not. Digesters are not profitable in California when the extra cost for NO_x control is included. Without that cost, 486 digesters would be installed with REAP grants or 134 without the grants. One explanation for the fact that the model projection does not correspond with the actual and projected installations in Pennsylvania and Wisconsin is that CO_2 prices have been positive in recent years, when many of these digesters were installed. Prices in the voluntary Chicago Climate Exchange market have been as high as $7 in recent years, and producers may have been basing their decisions on those prices. Producers may also have expected electricity price increases when they decided to install the digesters. Other explanations are that financial and technical assistance programs other than REAP available in those states which are not reflected in the model. Some digesters may also have been installed for odor control or other reasons not reflected in the model.

A $20 CO_2 price would increase the number of profitable digesters to 2,117 without REAP grants. A total of $1.1 billion in REAP funding would be required. A $40 price would bring the number of profitable digesters up to 4,138 (Tables 6 and 7). This only represent 3 and 6 percent of all farms at the two prices, but since the largest farms are significantly more likely to install a digester, this represents 38 and 49 percent of the dairy herd inventory. Digester adoption at the $20 price takes place mostly on the farms of 500 cows or more. A small percentage of the 200-499 cow farms install digesters at $20, but the number in this size category increases substantially at $40. The higher price also brings in a few digesters in the 100-199 cow size, but only in the states with the most favorable electricity rates. The digesters remain a tiny fraction of all farms in this size. No farms under 100 cows install digesters even at $40.

A scenario of REAP grants together with the $20 CO_2 price was also analyzed. Those results are not presented, however, because it is unclear how much additional REAP grant funding would be available if a higher price were to significantly increase digester installations. If enough REAP funding were available to fund all of the digesters that would be profitable with a 25 percent grant and a $20 price, the number of digester farms would be 3,155.

Table 3. CO_2 Reductions on a Minnesota Dairy Farm with Scraped Manure System Installing a Digester, Based on EPA Greenhouse Gas Inventory Methodology

Theoretical maximum CH4 emissions, metric tonnes/cow/year												
					Bo		VS					
0.29	mt CH_4	=	0.000676	mt CH_4	0.24	M^3 CH_4	2,967	kg manure	604	kg		
	cow /yr			M^3 CH_4		kg manure	1,000	kg cow/year		cow		
Baseline - current CH_4 emissions												
0.07	mt CH_4	=	0.29	mt CH_4		MCF		Higher for warmer climates and lagoons , e.g. 71% for TX farm w/lagoon				
	cow /yr			cow /yr		25%				75% for lagoons		
CH_4 production in heated digester												
						management		destruction		collection		
0.25	mt CH_4	=	0.29	mt CH_4		factor		efficiency		efficiency		
	cow /yr			cow /yr		90%		98%		99%		
CH_4 leakage from digester, CO_2-equiv. metric tonnes												
			[	100% -		collection	100% -	]	mgmt			
0.01	mt CH_4	=	collection eff.			eff.	destruction eff.		factor	0.29	mt CH_4	
	cow /yr			1%	+	99%	2%		90%		cow /yr	
Electricity production from heated digester CH_4							digester engine					
			online efficiency				thermal conversion					
874	kWh	=	90%		1	kWh	25%	BTU e	52	mm BTU CH_4	0.25	mt CH_4
	cow / yr				3,412	BTU e		BTU CH_4	1	mt CH_4		cow / yr
Utility CO_2 emissions avoided by producing electricity from digester CH_4 rather than coal												
			emissions from fossil sources									
0.82	mt CO_2	=		0.00093	mt CO_2		874	kWh				
	cow / yr				kWh			cow / yr				
Net CO_2 equiv reduction			Baseline emissions			Digester leakage				Utility emissions avoided		
2.18	mt CO_2	=	[0.07	mt CH_4	-	0.01	mt CH_4	] 21	kg CO_2	+	0.82	mt CO_2
	cow/yr			cow /yr			cow /yr		kg CH_4			cow / yr

Table 4. Incremental Cash flow analysis of a heated digester with electricity production on example dairy farms in two states.

Receipt Category	Price	Units	Quantity	Units		Value, $/cow/yr
Case I: Large Texas Dairy Farm (4,000 cows)						
net CO2-equivalent reduction	20	$	6.13	mt CO2 eq		122.60
		mt		cow/yr		
electricity generated	0.089	$	989	kw.hr e =		88.03
		kw.hr		cow / yr		
bedding						10.00
				total receipts		**220.63**
Outlay Category						
operation and maintenance	0.03	$ per $ capital				-19.59
annual capital cost	6%	interest	0.0872	$ / $ capital		-56.92
	20	years term		**total outlays**		**-76.51**
				net cash flow		**144.12**
capital outlay net of 25% grant	$ 653	$ / cow,	$ 2,611,514	total for	4000	cows
Case II: Small Minnesota Dairy Farm (500 cows)						
net CO2-equivalent reduction	20	$	2.18	mt CO2 eq		43.60
		mt		cow/yr		
electricity generated	0.063	$	874	kWh		55.08
		kw.hr		cow / yr		
bedding						10.00
				total receipts		**108.69**
Outlay Category						
operation and maintenance	0.03	$ per $ capital				-44.24
annual capital cost	6%	interest	0.0872	$ / $ capital		-128.56
	20	years term		**total outlays**		**-172.79**
				net cash flow		**-64.11**
capital outlay net of 25% grant	$ 1,475	$ / cow,	$ 737,264	total for	500	cows

Table 5. Digesters Currently Operational on U.S. Dairy Farms							
Digester Type, With or Without Electricity Generation							
State	Lagoon	Lagoon w/Elec.	Heated	Heated w/Elec.	All Digesters	Farms w/o Digesters	All Farms
California	2	9		4	15	2,150	2,165
Idaho				2	2	809	811
Michigan			2	3	5	2,642	2,647
Minnesota			2	3	5	5,143	5,148
New Mexico			1		1	271	272
New York	3	1	2	15	21	5,662	5,683
Pennsylvania				12	12	8,321	8,333
Texas	1		1		2	1,291	1,293
Washington			1	3	4	813	817
Wisconsin			3	22	25	14,133	14,158
Other states	0	0	3	28	31	28,532	28,563
US	6	10	15	92	123	69,767	69,890

Source: U.S. Agstar Digester Database, last updated April 2010. "Heated" type includes all digester types listed by Agstar other than those described as covered lagoons and one that was listed as of an unknown type. Those shown here in the "w/Elec." columns are those with a number shown for kW of installed capacity in the Agstar database.

Table 6. Model Projection of Farms Installing Digesters at Different CO2 Offset Values

State	Flare Only	w/Electrical Generation	All Digesters	Farms w/o Digesters	All Farms
	$0 per metric tonne, assuming that REAP grants cover 25 Percent of the investment				
California[a]	-	-	-	2,165	2,165
Idaho	-	-	-	811	811
Michigan	-	-	-	2,647	2,647
Minnesota	-	-	-	5,148	5,148
New Mexico	-	-	-	272	272
New York	-	71	71	5,612	5,683
Pennsylvania	-	-	-	8,333	8,333
Texas	-	36	36	1,257	1,293
Washington	-	-	-	817	817
Wisconsin	-	-	-	14,158	14,158
Other states	-	41	41	28,522	28,563
US	-	147	147	69,743	69,890
	--- $20 per metric tonne ---				
California	296	468	764	1,401	2,165
Idaho	73	105	178	633	811
Michigan	25	48	73	2,574	2,647
Minnesota	18	11	29	5,119	5,148
New Mexico	4	105	109	163	272
New York	-	123	123	5,560	5,683
Pennsylvania	14	4	18	8,315	8,333
Texas	-	152	152	1,141	1,293
Washington	119	45	165	652	817
Wisconsin	58	28	87	14,072	14,158
Other states	179	240	419	28,144	28,563
US	787	1,330	2,117	67,773	69,890
	--- $40 per metric tonne ---				
California	651	468	1,119	1,046	2,165
Idaho	59	226	285	526	811
Michigan	74	116	190	2,457	2,647
Minnesota	81	28	109	5,039	5,148
New Mexico	4	109	112	160	272
New York	102	216	318	5,365	5,683
Pennsylvania	51	26	77	8,256	8,333
Texas	115	152	267	1,026	1,293
Washington	111	139	250	567	817
Wisconsin	182	136	318	13,840	14,158
Other states	622	470	1,092	27,471	28,563
US	2,052	2,087	4,138	65,752	69,890

aThe California projection assumes that added capital and operating costs of $0.14/kWh for Nox reduction (from Koetsier) preclude electricity generation. Without that added cost, 486 digesters would be installed in California if REAP grants are available and 134 without REAP grants.

Emission reductions are 20 and 24 million CO_2-equivalent mt respectively at the two prices. Considering the EPA estimates of enteric fermentation and direct and indirect N_2O emissions discussed earlier, and adding in the fossil fuel electricity displacement by the digester electricity, the digester adoption would reduce dairy farm greenhouse gas emissions by 30 percent at the \$20 CO_2 price and 36 percent at the \$40 price. These percentage reductions ignore emissions elsewhere in the dairy value chain such as to produce the feed and process the milk.

The \$20 and \$40 prices would elicit 383 and 468 megawatts of additional electrical generating capacity, respectively. By comparison, another recent market analysis found that 2,500 U.S. dairy farms are candidates for digesters, with electricity generation potential of 403 megawatts of capacity at a 90 percent load factor (Roos, 2009). Roos did not state an assumption with regard to future CO_2 price. In our analysis, the largest numbers of digesters would be in California, Idaho, and Washington at a \$20 price, and California, New York, and Wisconsin at a \$40 price. Figures 1 through 3 show changes in digester numbers, emission reductions, and electrical generation capacity at CO_2 prices of up to \$100 aggregated over all 48 continental U.S. states and all farm sizes. Diminishing returns are evident at progressively higher CO_2 prices.

Table 7. U.S. Dairy Industry and Simulated Digester Adoption at Two CO_2 Prices, by Herd Size

	1 to 99	100 to 199	200 to 499	500 to 999	1,000 to 2,499	2,500 or more	All farms
Current situation							
Farms	53,324	8,975	4,307	1,702	1,104	478	69,890
Cows (000)	1,944	1,181	1,279	1,162	1,672	2,029	9,267
CO_2-equiv. emissions, Tg:							
Dairy cows - enteric fermentation and manure CH4 (@ 25 x CO_2)	NA	NA	NA	NA	NA	NA	66
U.S. economy total	NA	NA	NA	NA	NA	NA	7,150
Digesters	-	2	12	27	46	32	123[a]
Digester electrical capacity, MW	-	0	1	6	14	23	44[a]
Total U.S. electrical capacity, MW	NA	NA	NA	NA	NA	NA	1,067,010
\$20/mt CO_2 price							
Digesters	-	-	81	849	778	409	2,117
Cows on digesters (000)	-	-	26,731	583,553	1,188,718	1,754,090	3,553,092
CO_2-equiv. emission reductions, Tg	-	-	170,325	3,293,040	6,834,572	9,878,862	20,176,799
Digester electrical capacity, MW	-	-	-	14	145	224	383
\$40/mt CO_2 price							
Digesters	-	50	1,437	1,268	972	411	4,138
Cows on digesters (000)	-	7,087	437,147	872,957	1,468,505	1,762,210	4,547,905
CO_2-equiv. emission reductions, Tg	-	45,558	2,323,650	4,233,206	7,602,907	9,900,420	24,105,741
Digester electrical capacity, MW	-	-	-	61	182	225	468

[a]Includes four digesters for which herd size information is not available and 21 not listing electrical generation capacities.

Source: Farms and cows are from the USDA 2007 Census of Agriculture. Dairy enteric fermentation and N_2O emission data is from the EPA 2009 Greenhouse Gas Inventory. The electrical capacity is from the Energy Information Administration. Current digester information is from Agstar.

The minimum breakeven CO_2 price required for the farms of different sizes to find it profitable to install digesters are shown in Table 8 for the top ten dairy-producing states, assuming that no other public support such as REAP grants is available. While all of the farms with 2,500-plus cows would install digesters at prices of less than \$6, prices of \$39-55 would be required to justify digesters on the 100-199-cow farms.

Digester offset revenues for methane destruction may exacerbate consolidation in the dairy industry somewhat because digesters are not financially feasible below around 200 cows in most states. Methane destruction revenues under a \$40 CO_2 price will reduce the milk production cost by between \$2.19 and \$2.83 per 100 kilograms (\$0.99 and \$1.28 per 100 pounds) on farms of 2,500 cows or more. On farms of 200 to 499 cows, CH_4 destruction revenues would have less impact on milk production costs, from 70 cents to \$1.32 per 100 kilograms (32 to 60 cents per 100 pounds, Table 8). The latest milk production cost estimates from the USDA Economic Research Service show an average of \$50 per100 kilograms (\$22.73 per 100 pounds) of milk in 2009 (USDA Economic Research Service, 2010). Small farms in the 1 to 199 cow size range are likely to find digesters too costly to install.

Discussion, Conclusions, and Limitations

The two main conclusions of this analysis is that the breakeven CO_2 prices required for digester profitability vary quite widely with farm size and state, and that a higher carbon price would give larger farms more of a milk production cost advantage than they have currently. The \$20 scenario results are close to what the 2006 AgSTAR market study found as the market opportunity for dairy farm digesters, but that study did not specify the CO_2 price required to bring that opportunity to reality (U.S. AgSTAR, 2006). In percentage terms, the contribution to overall national electricity demand would still be small at a \$40 price – 468 mW is only 0.04 percent of total U.S. generating capacity.

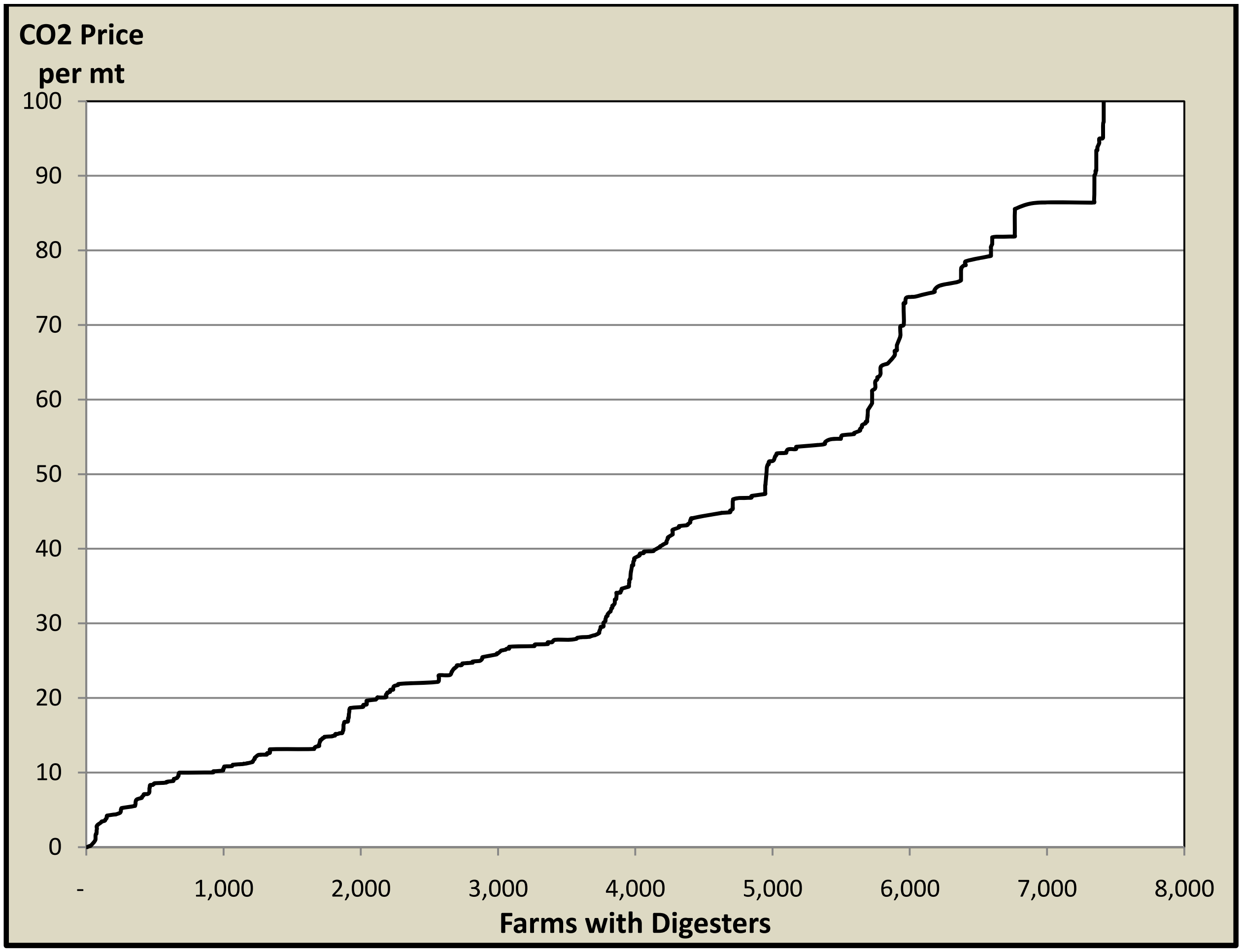

Figure 1. Digester Installations in Response to Increasing CO_2 Prices

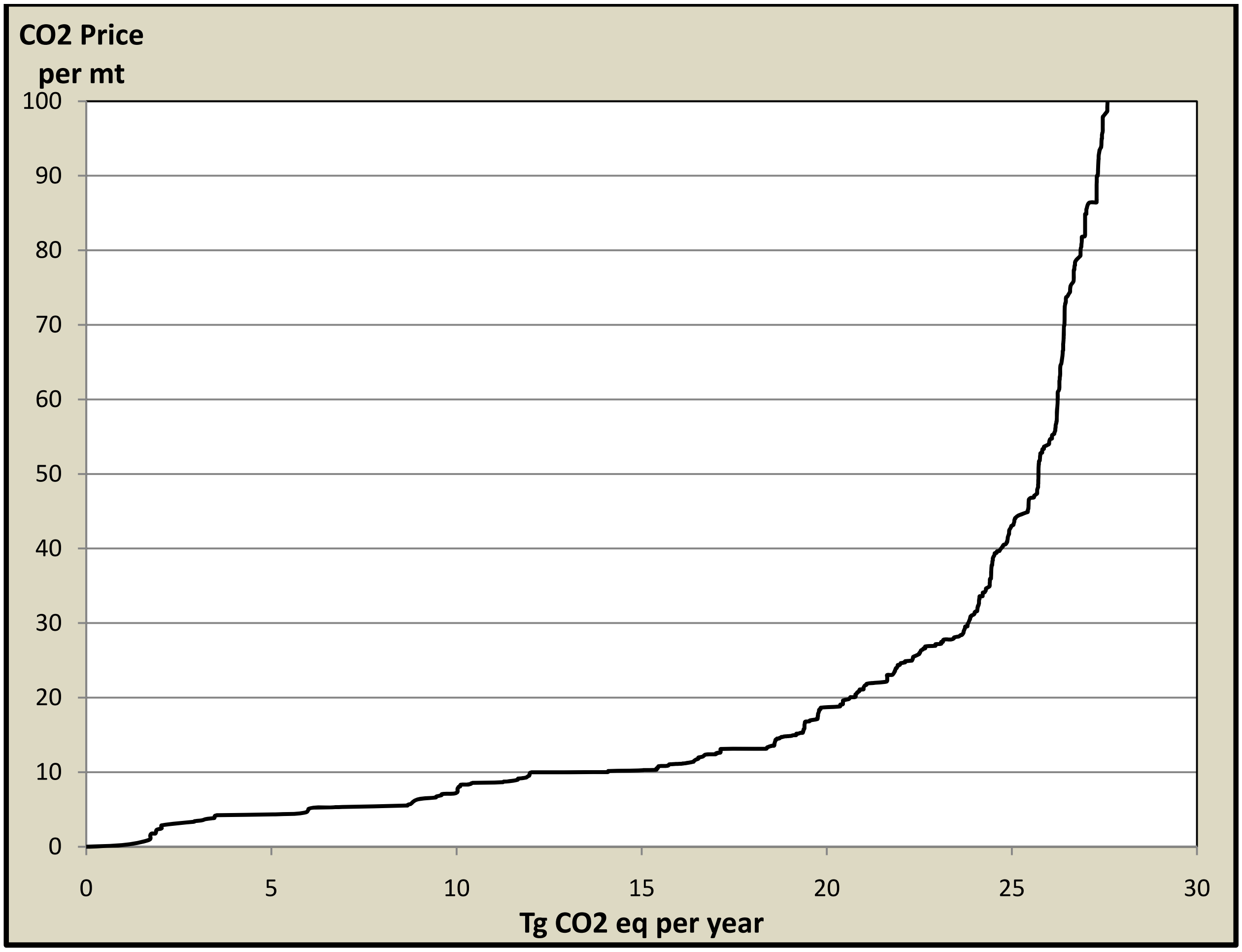

Figure 2. Emission Reductions in Response to Increasing CO_2 Prices

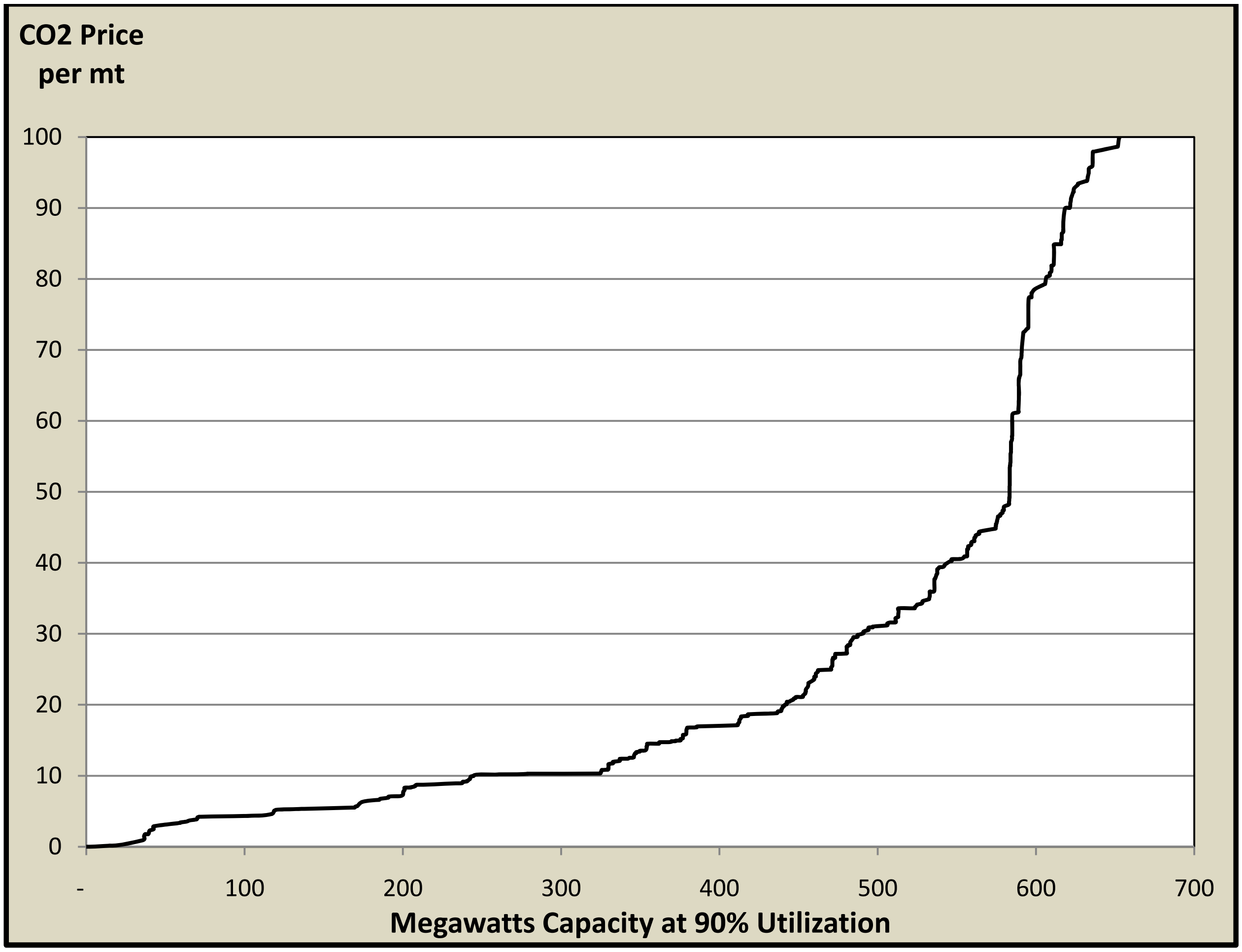

Figure 3. Electrical Generation Capacity Response to Increasing CO_2 Prices

Table 8. Minimum Breakeven CO_2 Price Required for Farms to Install Digesters, by State and Herd Size, $/Metric Tonne

	100 to 199 Cows	200 to 499	500 to 999	1,000 to 2,499	2,500 or more
California	$44.89	$22.14	$13.14	$10.01	$5.51
Idaho	43.15	20.08	11.13	8.60	4.33
Michigan	47.35	24.72	13.14	7.12	3.70
Minnesota	55.36	28.19	15.27	11.64	5.67
New Mexico	45.47	17.30	11.18	6.59	3.36
New York	52.84	25.83	10.85	3.53	0.00
Pennsylvania	54.72	27.91	15.16	8.99	3.42
Texas	44.38	23.05	12.40	4.61	0.64
Washington	39.67	19.77	11.39	8.64	4.39
Wisconsin	53.94	26.94	14.85	10.26	5.15

Table 9. Change in Cost of Producing Milk Due to Two CO2 Prices, for Farms Currently Using Lagoons for Manure Handling, by State and Herd Size, $ Per 100 kilograms[a]

State	100 to 199	200 to 499	500 to 999	1,000 to 2,499	2,500 or more
		--- CO_2 priced at $20 per mt ---			
California	***$0.00***	***$0.00***	-$0.37	-$0.61	-$0.92
Idaho	***0.00***	***0.00***	-0.55	-0.80	-1.14
Michigan	***0.00***	***0.00***	-0.38	-0.83	-1.05
Minnesota	***0.00***	***0.00***	-0.27	-0.51	-0.97
New Mexico	***0.00***	-0.16	-0.52	-0.91	-1.13
New York	***0.00***	***0.00***	-0.60	-1.08	-1.42
Pennsylvania	***0.00***	***0.00***	-0.28	-0.74	-1.12
Texas	***0.00***	***0.00***	-0.55	-1.11	-1.39
Washington	***0.00***	-0.01	-0.52	-0.80	-1.11
Wisconsin	***0.00***	***0.00***	-0.29	-0.65	-0.99
		--- CO2 priced at $40 per mt ---			
California	***$0.00***	-$0.97	-$1.45	-$1.88	-$2.19
Idaho	***0.00***	-1.24	-1.85	-2.25	-2.59
Michigan	***0.00***	-0.84	-1.62	-2.11	-2.33
Minnesota	***0.00***	-0.68	-1.43	-1.86	-2.32
New Mexico	***0.00***	-1.32	-1.87	-2.27	-2.49
New York	***0.00***	-0.79	-1.90	-2.38	-2.73
Pennsylvania	***0.00***	-0.70	-1.52	-2.10	-2.47
Texas	***0.00***	-1.04	-1.98	-2.54	-2.83
Washington	-0.02	-1.23	-1.80	-2.22	-2.53
Wisconsin	***0.00***	-0.74	-1.43	-1.98	-2.32

[a]States and herd sizes NOT installing digesters are underlined and in italics. These cost reductions compare to a U.S. average cost of $50 per 100 kilograms ($22.73 per 100 pounds) in 2009.

The cross-elasticity between CO_2 and electricity is illustrated clearly in Figure 3. Also, only around half to two-thirds of the farms installing digesters would find it attractive to generate electricity because of the electricity price variation across states and the economies of size in electrical generation. Of the 2,117 digesters installed at a \$20 CO_2 price, 1,330 or 63 percent would generate electricity. The number with electrical generation at a \$40 price is 2,087 or 50 percent of the 4,138 total.

Regarding digester revenues and CO_2 offsets, a representative dairy farm with an anaerobic lagoon manure system in a southern state such as Texas will have relatively high methane offsets, electricity generation and fossil fuel displacement due to the warm climate. In contrast, a dairy farm with a slurry system in a northern state such as Minnesota will have smaller methane offsets and electricity generation due to the cooler climate. The revenue differences make digester adoption moderately more lucrative in Texas than in Minnesota. Digester adoption would also be lucrative in California if not for the higher investment and operating costs for NO_x control.

However, economies of size may be the main determinant of digester adoption. At a typical large California dairy with 4,000 cows, the annual capital cost is \$57 per cow and the net cash flow is around \$144 per cow per year. In contrast, the annual capital cost is \$128 per cow in a small Minnesota dairy with 500 cows. Consequently, the annual net cash flow is significantly negative (-\$64), so digester adoption is not profitable.

The simplistic nature of the model is a limitation in that it assumes that all farms of a location, size, and manure system enter the solution at the same price, while in fact only a small percentage of such farms have installed digester to date. Some currently-operating digesters were installed as long as 30 years ago, when construction costs were lower than those assumed in the model. Finally, some digester operators may be extracting more value from the electricity or other digester outputs than assumed here.

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