We Energies

New Business Models for Customer-Owned Renewable Energy Generation

Final Report

March 2007

INTERNATIONAL

Passion. Expertise. Results.

This page deliberately left blank.

We Energies

New Business Models for Customer-Owned Renewable Energy Generation

Final Report

March 2007

Prepared for
We Energies
231 W Michigan Street
Milwaukee, WI 53203
(414) 221-2284

Prepared by:
ICF International
394 Pacific Ave, 2nd Floor
San Francisco, CA 94111
(415) 677-7100

Table of Contents

List of Tables

List of Figures

Executive Summary

Objective

To facilitate the deployment of customer-owned and customer-sited renewable energy generating technologies in its service territory and throughout Wisconsin, We Energies has launched an initiative to examine new business models that enable such technologies to become fully commercialized and cost-competitive in the marketplace through innovative approaches to addressing existing market barriers.

Approach

As customer-sited renewable energy generation is a form of distributed generation, business models involving such technologies must overcome many of the usual challenges that constrain broader application of distributed generation technologies—high initial costs, technical complexity, contractual and cost-related requirements pertaining to grid interconnection, environmental siting and permitting restrictions, etc. In addition, renewable energy business models face some unique challenges inherent in the various renewable energy resources: resource intermittency, immature technology, inability to leverage economies of scale, etc. The most successful distributed generation opportunities are large-scale installations that use a "waste" fuel (e.g., use of wood/paper waste in the forest products industry, or use of refining byproducts in the petroleum refining industry), and maximize efficiency and cost-effectiveness through the combined use of heat as well as power—opportunities that business models for customer-sited renewable energy generation are for the most part unable to leverage.

This analysis presents the results of research into business models for customer-owned/sited renewables that have been deployed in the United States and abroad. In addition to highlighting models that have an established track record of successful projects, this analysis also includes models that have met with barriers to successful implementation, and models that have not yet been implemented. This research is based on a comprehensive literature review as well as interviews with public and private-sector energy professionals. Though a broad cross-section of the energy professional community was contacted in connection with this research effort, this analysis is based on information gathered through informal telephone interviews rather than a systematic survey approach.

We have identified seven general business model categories to focus on in this analysis:

- **Community wind models**: Several different ownership and financing structures exist for promoting local ownership of utility-scale wind turbines, including: (1) the two most commonly-employed structures, the multiple local owner model and the flip model; (2) the consumer cooperative model that has been deployed successfully in Europe but which faces substantial implementation challenges in the United States; and (3) the public ownership model that has been successfully employed for behind-the-meter projects but which faces substantial implementation challenges when power is sold to third parties.
- **Multi-party ownership models for anaerobic digesters**: Two structures involving multi-party ownership have been developed for installation and operation of anaerobic digesters on dairy farms: (1) dual farmer/utility ownership and (2) community ownership. These models seek to address the high capital costs of digester technologies through ownership partnerships that provide cost-sharing for initial capital expenditures and ongoing maintenance.
- **Third party ownership models**: Several business models involving third party ownership of customer-sited renewable energy generation systems have been developed, including the

following: (1) utility ownership; (2) private sector ownership; and (3) cooperative ownership. Primarily targeting solar energy technologies to date, under third party ownership the customer incurs no up-front cost for the system and instead pays a fee for ongoing renewable energy service provision.

- **Project aggregation model**: Though implementation of the model has thus far been limited, project aggregation could provide a mechanism for attracting financing to commercial-scale, customer-owned projects.
- **Renewables-as-appliance models**: Business models that seek to make the purchase of renewable energy technologies more similar to that of other high-end appliances include the following: (1) employing high volume retail sales channels and (2) offering standardized equipment configurations that simplify design and installation requirements.
- **New construction model**: Targeting the residential new construction market, solar energy technologies can be incorporated as value-added features in new homes.
- **Environmental credit market models**: Business models may involve the use of environmental credits such as Renewable Energy Credits (RECs) or carbon credits as cash flow elements, potentially providing funding for installation of new projects.

Business model characterization

The new business models described in this analysis are distinctive in terms of the renewable energy technologies they address, the target markets and project sizes they are best suited to serve, and the types of entities that play a critical implementation role. The table below lists each model addressed in this analysis, the renewable energy technology or technologies that the model employs, the target market served by the model, the average project size, and the types of entities that would typically play a key role in initiating and implementing projects.

Table ES-1. New business model characterization

New Business Model	Relevant Technologies	Target Markets	Project Size	Implementers
Community wind	Utility-scale wind turbine	Agricultural, rural residential	Large	Project developer, community, local government
Dual digester ownership	Anaerobic digester	Agricultural	Large	Utility, equipment supplier
Third party ownership	Solar PV, solar thermal	Residential, C&I	Small or large	Utility, project developer
Project aggregation	Wind, solar PV	C&I	Large	Utility, project developer
Renewables-as-appliance	Solar PV, residential-scale wind turbines	Residential	Small	Retailer, manufacturer, supplier
New construction	Solar PV, solar thermal	Residential	Small	Real estate developer, manufacturer, supplier
Environmental credit market	Wind, solar PV, anaerobic digester	Residential, C&I, agricultural	Small	Project developer

Addressing existing market barriers

The objective of this analysis is to identify new business models that address one or more of the traditional barriers to broader application of customer-owned or customer-sited renewable energy technologies. The primary barriers considered in this analysis include:

- ***Initial cost barriers***: Upfront capital requirements that make the investment in renewable energy technology compare unfavorably with other potential investments and/or contribute to a longer-than-acceptable payback period.
- ***Transaction cost barriers***: Higher-than-acceptable costs associated with the time and effort required to implement a renewable energy project, including the time and effort associated with activities such as selecting appropriate technologies, making decisions, procuring equipment, obtaining necessary approvals, and arranging financing.
- ***Technical complexity barriers***: Initial and ongoing technical requirements that reduce customer willingness to invest in renewable energy technology.
- ***Risk barriers***: Real or perceived risks associated with purchasing renewable energy technology, such as the risk that the technology will not perform as expected, or that it will have a negative effect on property values.
- ***Informational barriers***: Misinformation, conflicting information, or lack of information regarding renewable energy technology that is perpetuated through existing marketing, information-sharing, or sales channels.

The following table presents a summary of the barriers that each new business model is suited to address.

Table ES-2. Barrier matrix

New Business Model	Initial Cost	Transaction Cost	Technical Complexity	Risk	Informational
Community wind	X	X			
Dual digester ownership	X	X	X	X	
Third party ownership	X	X	X	X	
Project aggregation	X	X			
Renewables-as-appliance	X	X	X	X	X
New construction	X	X	X	X	X
Environmental credit market	X	X			

It is important to note that though new business models may provide mechanisms for overcoming traditional barriers to customer-owned or customer-sited renewable energy development, the models themselves may entail barriers to broader implementation. Within the discussion of each new business model, we consider what advantages the model offers in terms of promoting renewable energy development, as well as the potential disadvantages each model is likely to face.

This page deliberately left blank.

1. Introduction

1.1. Objective

We Energies has the goal of facilitating the deployment of distributed renewable energy generation technologies in its service territory and throughout Wisconsin. To achieve that goal, We Energies has launched an initiative to examine new business models that employ innovative approaches to enable such technologies to become fully commercialized and cost-competitive in the marketplace. These new business models are designed to overcome existing market barriers to distributed renewable energy technologies, including cost, technical, risk, and informational barriers.

This analysis presents the findings from an assessment of innovative new business models that have been used to promote the deployment of distributed renewable energy generating technologies in Wisconsin as well as across the United States and abroad. We employ a broad definition for the term "business model" that includes innovative ownership and financing structures, partnerships, and programs. This analysis includes business models that promote customer ownership of renewable energy generation systems as well as models involving third party or multi-party ownership of customer-sited systems. The findings from this study will be used in connection with stakeholder workshops We Energies will convene in March 2007. Engaging a broad cross-section of Wisconsin energy professionals and energy end-users interested in promoting the deployment of renewable energy generating technologies, these workshops will seek to identify the new business models that show the greatest promise for increased deployment in Wisconsin, and provide guidance to We Energies on how it can best support such deployment.

1.2. Approach

To collect a wide array of potential new business models to be included in this analysis, the research effort began by contacting a broad cross-section of renewable energy professionals in the public and private sectors, including experts involved in renewable energy advocacy, state policy, program implementation, and project financing. Experts from Wisconsin and across the country were contacted to elicit suggestions for models to be included in this analysis. We also conducted a review of relevant literature, including publications by the Lawrence Berkeley National Laboratory (LBNL), the National Renewable Energy Laboratory (NREL), and a number of analyses produced by Focus on Energy and other organizations working to promote renewable energy in Wisconsin.

Using the suggestions for potential new business models that were elicited during interviews with renewable energy experts and the literature review, we conducted a second round of in-depth telephone interviews with practitioners involved in the implementation of these models. The information collected during the second round of interviews has been used to develop detailed case studies of the new business models included in this analysis, as well as to augment our overall assessment of each model. The full list of energy professionals contacted and interviewed in connection with this analysis is shown in Table 1-1.

Table 1-1. Energy professionals contacted and interviewed

Organization	Contact Name	Interviewed
AgRefresh	Jeffrey Frost	
American Corn Growers Foundation	Dan McGuire	X
American Council on Renewable Energy	Michael Eckhart	
American Wind Energy Association	John Dunlop	X
Birch Tree Capital	John Harper	
Boreal Renewable Energy Development	Tom Michelman	X
Carbonfund.org	Eric Carlson	X
Cascade Solar Consulting	Doug Boelyn	
Citizens Energy Cooperative of Wisconsin	Chamomile Nusz	X
City of Portland	Dave Tooze	
Clean Energy States Alliance	Jennifer DeCesaro	X
Community Energy/New Wind Energy	Jeff Keeler	
Dairyland Power	Neil Kennebeck	X
Dane County Dept. of Public Works	John Reindl	X
DanMar & Associates	Dan Juhl	X
EcoEnergy LLC	Wes Slaymaker	X
Electric Solar Utility Network	Jill Cliburn	X
Energy Center of Wisconsin	Ingrid Kelley	
Energy Trust of Oregon	Alan Cowan	X
Environmental Credit Corp	Scott Subler	X
Environmental Law & Policy Center	Howard Lerner	
Focus on Energy/L&S Technical Associates	Larry Krom	X
Fresh-Energy	Michael Noble	
Great River Energy	Jon Brekke	
Interstate Renewable Energy Council	Jane Weissman	
John Deere	Todd Velnosky	
Lake Michigan Wind & Sun	John Hippensteel	
Lakeland Electric	Jeff Curry	X
Lawrence Berkeley National Lab	Mark Bolinger	X
Madison Area Technical College	Ken Walz	
Massachusetts Technology Collaborative	Kristen Goland	X
Microgy	Mike Casper	X

Midwest Renewable Energy Association	Tehri Parker	
Midwest Wind Energy Finance LLC	Ken Valley	X
Minwind I LLC	Mark Willers	
MIT Community Solar Power Initiative	Steve Lanou	
Montgomery County Maryland	Eric R. Coffman	
MSB Energy Associates	Mark Daugherty	X
North American Hydro	Chuck Alsberg	
North American Water Office	George Crocker	X
North Carolina Solar Center	Sue Gouchoe	X
Northwest SEED/Our Wind Cooperative	Jennifer Grove	X
Northwest Solar Center	Mike Nelson	
Port of Tillamook Bay	Jack Crider	X
Port of Tillamook Bay	George DeVore	X
RENEW Wisconsin	Michael Vickerman	X
RENEW Wisconsin board member	John Bahr	X
Sacramento Municipal Utility District	Jim Burke	
ScotianWindFields	Dana Morin	X
Seventh Generation Energy	Alex DePillis	
Solar Electric Power Association	Julia Judd	
Solar Energy Industry Association	Rhone Resch	
Solar Mining Company	Clarence Wickham	
Sun Edison	Jigar Shah	
Washington Suburban Sanitary Commission	Rob Taylor	
Windustry	Lisa Daniels	
Wisconsin DATCP	Roger Kasper	X
Wisconsin Energy Conservation Corporation	Don Wichert	X
Wisconsin Power Control	Steve Tweed	

1.3. Organization of the report

This report provides a detailed assessment of seven broad categories of innovative business models for customer-owned or sited renewable energy generation:

- **Community wind models**: Ownership and financing structures promoting local ownership of utility-scale wind turbines.
- **Multi-party ownership models for anaerobic digesters**: Multi-party ownership and financing structures for anaerobic digesters on dairy farms.
- **Third party ownership models**: Third party ownership of customer-sited renewable energy generation systems.
- **Project aggregation model**: Aggregation of multiple renewable energy projects to facilitate project financing.
- **Renewables-as-appliance models**: Utilization of high volume retail sales channels and standardizing equipment configurations for residential-scale renewable energy applications.
- **New construction model**: Renewable energy technology applications in new residential construction.
- **Environmental credit market models**: Mechanisms for accessing environmental credit markets to provide funding for customer-owned renewable energy generating equipment.

In each section, we provide an assessment of the advantages and disadvantages of each model and primary implementation challenges. Where data are available, we provide detailed case studies of programs or projects that implement the model, as well as cash flow analyses for sample projects.

2. Community wind models

In areas with sufficient wind resources, utility-scale wind turbines are one of the most cost-effective technologies for procuring substantial renewable energy generating capacity. In recent years community wind business models have become a mechanism for promoting local ownership of utility-scale wind turbines. Bolinger et. al (2004) define community wind as "locally owned projects, consisting of one or more utility-scale (600 kW or greater) wind turbines that are interconnected on either the customer or utility side of the meter."

Advantages

In an interview conducted for this analysis, Bolinger (2006) provided several reasons why community wind may be an attractive ownership model for customer-sited renewable energy generation:

- **Promotes rural economic development**: Several studies have shown that locally-owned wind projects are more beneficial to rural economies than commercially-owned wind projects. Most notably, a 2004 study by the U.S. Government Accountability Office (GAO) compared the county-level employment and income impacts of a 40 MW wind project owned by an out-of-state firm with those of 20 small projects totaling 40 MW of capacity owned by county residents. Based on modeling conducted by NREL, the community-owned projects produced at least two times the number of jobs, and two to three times the amount of income. The same study concludes that the larger and more diverse a county's economic base, the greater the local benefits in terms of jobs and income, as labor and materials can be procured locally rather than imported.
- **Creates new revenue streams for farmers**: According to American Wind Energy Association (AWEA) data cited in the GAO study, most wind projects in the United States are sited on privately-owned agricultural land. Though lease payments for 1 MW of installed commercial turbine capacity offer revenues of $2,000 to $5,000 per year, per-turbine revenues are likely to be higher if the farmer has at least a partial ownership stake in the project (GAO 2004). Wind energy revenues are more stable than crop revenues, which is one reason the American Corn Growers Foundation has been a strong advocate for community wind development since 2001 (McGuire 2006). However, GAO notes that due to the high costs of utility-scale wind turbines, a commercially-owned project with greater financial resources may be able to install more turbines and thus offer higher overall revenues to the farmer than a farmer-owned project (GAO 2004).
- **Increases community acceptance**: Ensuring a local financial/ownership stake in a wind project may reduce the magnitude of opposition to a proposed project. According to Bolinger (2006), the political battles over commercial wind projects in the Northeast have led to efforts to promote community wind development in the region. In other cases, piggybacking community-owned turbines on a large commercial project may reap the benefits of economies of scale while offering greater incentives for community support of the project (see sidebar on the following page, *Piggybacking Community Wind on Commercial Projects*).
- **Fills unique project size niche**: According to Bolinger (2006), one reason that the State of Oregon is promoting community wind as part of its renewable energy development strategy is that the average project size (10-20 MW) fills a niche between large-scale commercial projects (30-300 MW) and residential-scale wind installations. In some rural areas, community wind projects may be possible in places where limited transmission infrastructure capacity makes larger-scale projects unviable.

Barriers

According to Bolinger et. al. (2004), community wind projects may face a number of barriers, including the following: (1) financing difficulties, including the inability of smaller investors to fully utilize tax credits; (2) poor economies of scale; (3) regulatory barriers such as securities regulations and IRS restrictions that present challenges for project financing; (4) unfavorable power buyback rates; and (5) burdensome interconnection requirements. Several ownership and financing structures have been developed to address these barriers, though certain barriers may be best addressed at the policy level (for example, policies that standardize interconnection requirements or mandate buy-back rates). This section describes several ownership/financing models for community wind projects, summarizing the advantages and disadvantages of each in terms of overcoming barriers to customer-owned renewable energy generation.

> **Piggybacking Community Wind on Commercial Projects**
>
> Several sources consulted in connection with this analysis mentioned that there is growing interest in including one or more locally-owned turbines in large-scale commercial wind projects. Advantages of such an approach could include the ability to take advantage of the economies of scale offered by the larger project, reducing expenditures for feasibility and interconnection studies, etc., as well as the possibility of improved access to turbine supply in a tight market.
>
> We have not developed a full summary of the piggybacking model because it could potentially employ any of the ownership/financing structures considered in this analysis, but consider it to be worth mentioning as it may offer the opportunity for increased local financial benefits from large-scale wind projects as well as the potential for increased community support of large-scale projects.

- **Multiple local owner model**: This model was employed for one of the first community wind projects, the Minwind project in Minnesota, and may offer the greatest financial returns for investors with sufficient tax liability.
- **Flip model**: The flip is one of the most common ownership structures (aside from the multiple local owner model) and is customizable to meet project-specific financing requirements.
- **Consumer cooperative model**: Though there are no examples in the United States of successful community wind projects employing a true cooperative ownership structure, the model has been successful in some European countries. (The cooperative model does not include projects initiated by rural electric cooperatives.)
- **Municipal ownership model**: Community wind turbines may be publicly owned by municipalities or local government entities (school districts, etc.) to offset energy use at public facilities or (depending upon local regulations) for the sale of power to distribution utilities. Under some circumstances public entities may be able to reap the benefits of lower-cost financing mechanisms such as municipal bonds.

Where data are available, the detailed descriptions of each model in the following sections also provide project case studies and cash flow analyses.

2.1. Multiple local owner model

The multiple local owner model is one of the more commonly-employed community wind ownership structures (Bolinger et. al. 2004). In this model, a group of local investors forms a limited liability corporation (LLC) to own and operate the project, selling power to a utility under the terms of a negotiated power purchase agreement (PPA). Equity financing is raised through the sale of shares in the project. Debt is obtained through a bank or loan fund supporting renewable energy development. Revenues and tax incentives are divided between the project investors in accordance with their proportional ownership share in the project.

- Advantages cited by Bolinger et. al. (2004) include:
  - Sale of electricity to an unrelated third party means the project is eligible for the federal tax incentives such as accelerated depreciation and the production tax credit (PTC), and possibly state tax incentives as well.
  - Of the seven models evaluated by Bolinger et. al., this model is the most financially competitive as long as the investors are able to capture at least 65 percent of the value of the federal PTC.* (Note that the Bolinger et. al. financial analysis involved Oregon-specific parameters.)
- Disadvantages cited by Bolinger et. al. (2004) include:
  - Sale of shares either requires securities registration or exemption from registration requirements, which increases the legal expenses involved with setting up a project.
  - The model becomes less financially competitive when investors have insufficient tax liability to take full advantage of the PTC and other tax incentives. Passive investors that are not actively involved in developing or managing the project must have passive income (e.g., rental income) against which to offset the tax incentives.
  - Administrative costs may be as much as two times higher than under other models (like the flip model) due to the need for coordination and communication between multiple investors.

Case study: Minwind

The Minwind project in Minnesota was the first to employ the multiple local owner model, and is described in the following case study.

Project Name	**Business Model Type**
Minwind I & II	Community wind – multiple local investor model
Location	**Utility**
Rock County, Minnesota	Alliant Energy (although a local cooperative is the electric supplier, Minwind executed the renewable power purchase agreement with Alliant).

Case study references

- Mark Bolinger, Ryan Wiser, Tom Wind, Dan Juhl, Robert Grace (July 2004). *A Comparative Analysis of Community Wind Power Development Options in Oregon*. Available at: http://www.cleanenergystates.org/library/Reports/OR_Community_Wind_Report.pdf

* Bolinger et. al. note that the aggregated net metering model is actually the most financially competitive of the community wind ownership models they evaluated, but its competitiveness is discounted due to the substantial barriers toward implementing this model in the United States (see Section 2.3). We Energies allows net metering of renewable generation up to 100 kW for wind and 20 kW for other renewable generation.

- Clean Energy Resource Teams (2002). *Case Study: Minwind I and II: Innovative Farmer-Owned Wind Projects.* Available at: http://www.cleanenergyresourceteams.org/southwest/CS-Minwind%20I%20&%20II.pdf
- Windustry (2002). *Fall Newsletter*, "Minwind I & II: Innovative Farmer-Owned Wind Projects." Available at: http://www.windustry.org/newsletter/2002FallNews.htm

Project ownership/management structure

To maximize the project's ability to use tax credits and other incentives, two farmer-owned LLCs were created: Minwind I and II. The project was subdivided so it would be eligible for the Minnesota production incentive for "small wind" projects less than 2 MW. Another advantage of subdividing projects may involve keeping the per-project number of investors below the threshold for securities regulation.[†] The LLC structure protects individual investors from personal financial liability.

The Minwind LLCs required that 85% of shares must be farmer-owned, with remaining shares open to other local investors; no single party could own more than 15% of shares. Each investor was allowed one vote, regardless of the number of shares purchased. The LLCs obtained additional financing from local banks. Consultants were hired to assist with project development and negotiation of the power purchase agreement.

Project siting and metering

The project is sited on a farm owned by a Minwind investor and is interconnected on the utility side of the meter.

Factors ensuring project success

According to Bolinger et.al. (2004), the Minwind model has been so successful and popular with investors that investors initiated seven additional Minwind projects. These projects raised $6 million in equity over the course of two meetings and turned away 75 interested investors. Factors contributing to the success of the project include:

- Investor enthusiasm primarily due to expected high rate of return (17% per year).
- State production incentives (Minnesota production incentive of 1.5¢/kWh for 10 years, which is no longer available).
- Business model that facilitates local investment and maximizes eligibility for available incentives and tax credits.
- As most of the 66 investors are members of a cooperative that owns a local ethanol plant, Bolinger et.al. (2004) cite the importance of an established business relationship between the partners and familiarity/comfort with cooperative business models.

Key stakeholders

- Local investors (mostly farmers).
- Loans were obtained from the local branch of Farmers and Merchant's Bank, which had established relationships with LLC members through providing financing for the cooperatively owned ethanol plant.
- Power purchaser is Alliant Energy.

[†] Environmental Law & Policy Center (2004). *Community Wind Financing Handbook*. Available at: http://www.elpc.org/documents/WindHandbook2004.pdf

Capital & installation costs

$3.6 million

Operational costs (annual)

Unknown, though Bolinger et.al. estimate that the “multiple local owner” model for community wind will incur relatively high administrative expenses (estimated at $10,000 per year for a 1.5 MW project) because of the requirements for keeping multiple investors informed/organized.

Duration of project construction/installation

25 months

Comparison of actual costs with expected costs

Unknown

Initial funding source(s)

- 30% of the capital costs (approximately $1.1 million) were supplied by 66 local investors buying in at $5,000/share.
- 70% of the capital costs were supplied by loans from local banks.

Ongoing funding source(s)

- 15 year power purchase agreement with Alliant Energy.
- Minnesota production incentive (1.5¢/kWh for 10 years).
- Federal PTC (Bolinger et.al. write that as of 2004, the Minwind projects have not been able to capture the full value of the PTC in the year that it accrues, though much of the value may eventually be recovered in future years through carry-overs).

Federal/state/local/utility incentives facilitating development of the project

- Minnesota production incentive.
- Federal PTC.
- Unknown whether Minwind I and II received other grants helped to finance the project, but Minwind III – IX (14 MW total) have received $178,000 in USDA grants which will be used to build a substation to connect projects to the grid.

kWh (specify time period)

Unknown

Capacity factor

Unknown

Utility buy-back rate (if applicable)

Unknown

Rate of return

Average annual return for Minwind investors is expected to be 17% per year. (Bolinger et. al. estimate projects using the Minwind business model will generate average IRR of 10%).

Payback

10 years (expected)

Description of installed equipment

The total project (Minwind I and II) consists of four 950 kW Micon turbines installed on the same farm.

Other technologies considered

Unknown

Were any technical problems encountered, and if so, how were they addressed?

Unknown

Project goals

- Investment opportunity
- Local economic development

Project history

- Co-owners of an ethanol plant – mostly local farmers – were looking for new economic development opportunities.[‡]
- Formed a board of directors to pursue the possibility of a community wind project.
- Spent approximately $198,000 in up-front costs (primarily legal and consulting fees) to determine appropriate business model and establish LLCs. (Bolinger et.al. note that now that Minwind has established a successful business model, startup costs would be much lower for similar projects – estimated at $30,000 for legal and other up-front costs).
- Hired a consultant to develop the project and negotiate power purchase agreement.

Utility or government program initiating the project

None, though the project takes advantage of state production incentives and federal tax incentives.

Role played by the electric utility

The local rural electric cooperative is not involved in the project (see below).

Obstacles encountered and addressed

According to Mark Willers (president of Minwind I), negotiating the power purchase agreement was the most difficult aspect of the project. Initial negotiations with the local electric cooperative failed because of interconnection requirements and the co-op's exclusive agreements with other generators. Eventually an agreement was negotiated with Alliant Energy to purchase the power.

Regulatory hurdles

Sale of equity shares to local investors required an exemption from securities registration requirements at the state and federal levels. According to Bolinger, legal and administrative fees associated with the exemption processes can be substantial ($20,000 for Minwind), and state and federal exemption requirements may not be well aligned.

‡ Tom Arends (November 2002). *Minwind I & II: Success Stories?* Presentation at the Windustry conference:" Wind Energy: New Economic Opportunities." Available at: http://www.windustry.org/conferences/november2002/nov2002_proceedings/community/success.htm

Cash flow analysis: multiple local owner model

We developed a simplified cash flow analysis spreadsheet for a community wind project employing the multiple local owner business model. Modeling a sample project with an installed capacity of 1,500 kW, we employed the following assumptions: capacity factor of 28 percent[§]; installed cost of $2,250 per kW; annual O&M costs[**] of 3 percent of the installed project cost, increasing at the annual rate of 2 percent; initial legal fees of $10,000 reflecting the added legal services requirements as compared with the flip model; and an additional administrative expense of $10,000 per year due to the greater administrative burdens associated with the multiple-investor ownership structure. We assumed that the project is financed with 70 percent debt and 30 percent equity, with debt obtained through a 10-year commercial bank loan at an annual interest rate of 11.25 percent. (An interest rate premium of 3 percent over Prime was assumed due to balance sheet financing). Equity is obtained through a state grant of $46,000, a USDA grant of $200,000, and the sale of 153 $5,000 shares to local investors. We also assumed that the local investors have sufficient passive income to be able to recoup 100 percent of the value of the federal PTC and accelerated MACRS depreciation.[††] Electricity produced by the project is sold under a 20-year PPA at the rate of 6.5 cents per kWh, increasing 2 percent annually. A combined state and federal income tax rate of 40 percent is assumed. Construction expenses are incurred in Year 0, and all operating revenues and expenses (including loan interest and principal payments) are incurred beginning in Year 1. We used a 10 percent discount rate for the net present value (NPV) calculations.

As shown in Figure 2-1 below, the project's post-tax annual cash flows are positive in Years 1 through 3 while the tax benefits of accelerated MACRS depreciation are greatest. Annual cash flows become positive again in Year 11 once the loan is paid off. Figure 2-2 shows that the post-tax cumulative cash flow (payback) is negative for the duration of the project. The NPV of the annual cash flow for Years 0-10 is -$812,000 and the NPV of the annual cash flow for Years 0-20 is -$586,000. These results indicate that under the assumptions referenced above, the multiple local owner model is not financially viable at the power purchase rate of 6.5 cents per kWh.

§ A 28% capacity factor is at the high end of the expected range for wind turbines in Wisconsin (23% to 28%).

** O&M expenses include property tax payments, insurance costs, payment into an equipment repair and replacement fund, and management expenses.

†† As noted previously, local investors not actively involved in managing the project must have sufficient passive tax liability (e.g., rental income) in order to recoup the full value of federal tax incentives.

Figure 2-1. Annual cash flow, multiple local owner model

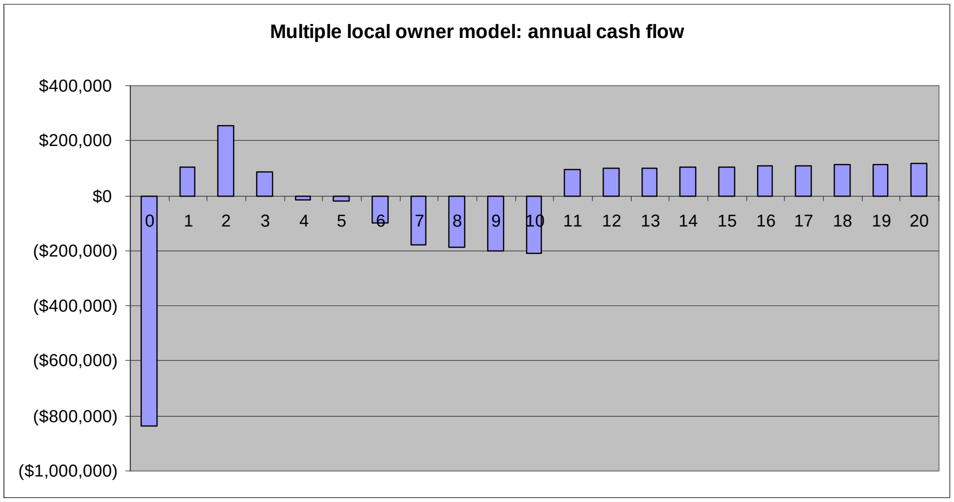
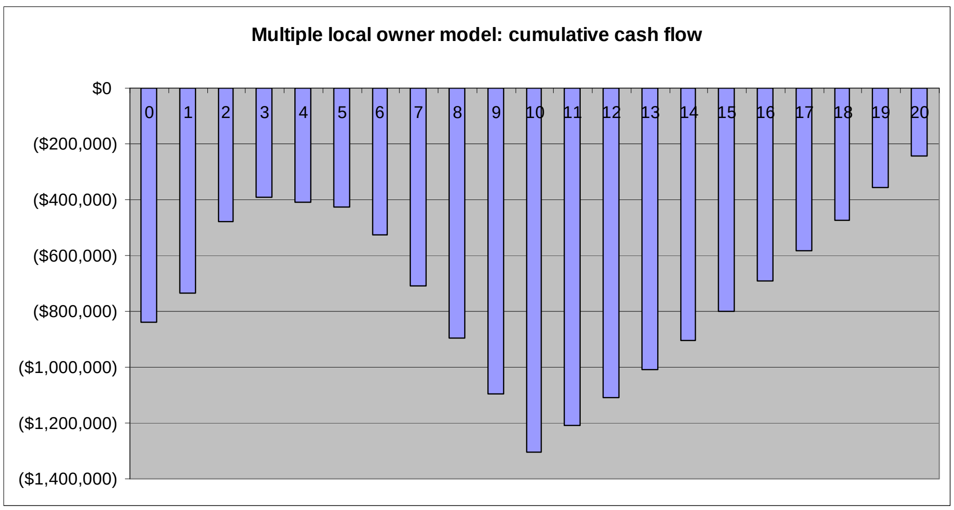


Figure 2-2. Cumulative cash flow, multiple local owner model



Revising assumptions about the relative magnitude of the project's debt and equity fraction, the loan interest rate, and the power purchase price all have a positive effect on the project's financial viability. With 50 percent debt and 50 percent equity, an interest rate of 8.25 percent (Prime), and a starting power purchase price of 9 cents per kWh, the project achieves a 21-year IRR of 9 percent, and payback in Year 12, though the NPV of 11- and 21-year cash flows is still negative.

2.2. Flip model

There are multiple variations of the basic "Minnesota-style flip" structure described by Bolinger et. al. (2004), including the "Wisconsin-style flip" model developed on behalf of Focus on Energy (see sidebar, *Wisconsin Flip Model*.) In the Minnesota model, a single investor or group of investors forms an LLC and partners with a corporation that has sufficient tax liability to take full advantage of the federal PTC and accelerated depreciation. The local investors contribute as little as 1 percent of the equity required to finance the project, with the corporation supplying as much as 99 percent. (The relative magnitude of these ownership shares are one of the variables that can be adjusted within the model.)

The partnership owns and operates the project, selling power to a utility under the terms of a negotiated PPA or a standard tariff like Minnesota's C-BED tariff. Under its majority ownership share, the corporation recoups the return on its investment by receiving the majority of revenues and tax incentives for 10 years (the PTC expiration period) or until its investment is paid off. At this point, the local investors become the majority owners in the project, and the tax-motivated investor becomes the minority owner or drops out entirely. The Environmental Law & Policy Center (ELPC) cautions that under federal tax law, the corporation must either retain its share in the project or sell the project to the local investors at fair market value (FMV), as determined by an independent third party, rather than a pre-arranged price (Kubert 2004). The IRS position (which is presently under review) is that the equity investor must retain at least a 10 percent share in the project after the flip, or FMV requirements are triggered (Valley 2006).

Wisconsin Flip Model

In 2003 Cooperative Development Services of Madison, on behalf of Focus on Energy, developed a business plan for a variation on the Minnesota-style flip structure which Bolinger et. al. (2004) refer to as the "Wisconsin-style flip." As with the Minnesota-style flip, this model involves a partnership between a local LLC and a tax-motivated corporate investor. Instead of contributing equity to the project, the LLC provides a loan to the corporate investor. The investor contributes all of the equity for the project, and the remaining financing is provided by a commercial bank loan. The corporation is the sole project owner for the first 10 years, receiving all revenues and tax benefits while paying off the commercial loan and also paying interest to the local owners on the LLC loan (interest payments are the LLC's sole income for the first 10 years of the project.) Upon expiration of the federal PTC at the 10-year mark, the corporation drops out, retaining the LLC loan principal as payment for the project. The LLC becomes the full owner of a debt-free project.

We have not developed a full summary of this model because it has not yet been implemented to date, in part due to the potential legal issues around what could be perceived as a pre-arranged sale between the corporation and the local LLC. Bolinger (2006) believes this problem could be resolved with minor adjustments to the model.

According to Ken Valley of Midwest Wind Energy Finance (2006), it is important to structure the deal to avoid imposing burdensome financial obligations on the part of the local landowners at the time of the flip. John Deere Credit has an established business unit that provides debt financing, equity investment, and project development services for community wind projects employing the flip structure, but Valley predicts the contractual requirements for FMV payments are likely to be problematic for local investors.

- Advantages of the flip model include:
  - For local investors lacking sufficient tax liability to capture the full value of the federal PTC, the model offers a way to make the project financially viable.
  - Sale of electricity to an unrelated third party means the project is eligible for the federal PTC, and possibly also state tax incentives.
  - Local owners must only raise a relatively small initial contribution, and under ideal circumstances will earn revenue from a debt-free (or mostly debt-free) project after the ownership flips and they become the majority owners.
- Disadvantages include:
  - It may be difficult for the local investors to find a tax-motivated partner to invest in the project (Bolinger et. al. 2004). According to Slaymaker (2006), institutional investors may accept lower rates of return (8-9 percent), but are typically only interested in larger-scale

investment opportunities than are offered by the typical community wind project. Some brokers (like Midwest Energy Finance LLC) specialize in financing these types of smaller-scale projects, but may demand a higher rate of return. Valley's firm seeks a typical return in the range of 10.5 – 11 percent for projects of 5 turbines or more, and a return of 12 percent for a one-turbine project.

- In cases where the tax-motivated investor drops out of the project entirely at the time of the flip, the fair market sale of the property to the local investors may require re-financing, so the project may not be entirely debt-free after the flip. According to Slaymaker (2006), this entails some risk that local investors should be aware of prior to initiating a project.
- If turbines are not properly maintained during the first ten years of the project, the local investors could be left with substantial operating expenses during the later years when incentives are no longer available.
- The somewhat complicated ownership/financing structure necessitates up-front costs for legal and tax advice (though lower than would be expected for the multiple local owner model).

According to one developer who works on community wind projects in Wisconsin, a possible solution to overcoming the financing hurdle may lie with aggregating multiple community wind projects under a single PPA and financing arrangement (Slaymaker 2006). According to Slaymaker, Edison Mission Energy (a subsidiary of Edison International which also owns Southern California Edison) has financed aggregated community wind projects in Minnesota. The challenge with this approach is the difficulty of aligning multiple projects with different landowners on a similar timeline. This approach is most feasible when it involves multiple landowners on adjacent properties (Valley 2006).

EcoEnergy LLC is currently developing the EcoDane project in Dane County that brings together four landowner/investors on a combined 10 MW community wind project. In another variation on the basic flip model, EcoEnergy LLC will be the majority shareholder after the "flip," minimizing the risk for landowner/investors. Though the project is still in development, we include details on this proposed project in the following case study, as an example of a Wisconsin community wind project employing the flip structure and using aggregation of multiple landowners to improve the project economics.

Case study: EcoDane

Project Name	**Business Model Type**
EcoDane	Community wind – flip model
Location	**Utility**
Springfield, WI	TBD – in PPA discussions with MG&E and other potential purchasers

Case study references

- Personal communication with Wes Slaymaker, EcoEnergy LLC, November 14, 2006.
- EcoEnergy LLC (September 2006). *EcoDane Wind LLC Summary.*

Project ownership/management structure

The planned project will employ a flip structure with a tax-motivated equity investor serving as the majority shareholder in EcoDane Wind LLC for the initial term (approximately 10 years or until the debt is paid off). EcoEnergy LLC, a developer of smaller-scale wind projects, will serve as a minority shareholder until the time when the project “flips,” at which point the company will become the majority shareholder. The local investors will also be minority shareholders and receive lease payments as well as dividends throughout the lifetime of the project. 320 acres are under lease with a 5-year option and 30-year term. Lease payments will be based on a fixed amount per installed MW, increasing for inflation at the rate of 1.5 percent per year. Landowner contributions will include grant funding obtained through Focus on Energy or other potential funding sources.

Project siting and metering

The planned project is expected to include six turbines located on separate parcels, interconnected into MG&E’s 13.8 kV distribution lines, traveling 1.5 miles to the MG&E lines at Highway 12.

Factors that will determine project success/failure

- Ability to find a tax-motivated investor.
- Negotiation of power purchase price once financing arrangement is established.

Key stakeholders

- Local landowner/investors: minority shareholders and lessors of land where turbines are sited.
- EcoEnergy LLC: project developer; minority shareholder before the “flip” and majority shareholder after the flip.
- Utility purchasing power from the project: not yet determined.
- Tax-motivated investor: not yet determined.

Capital & installation costs

Estimated at $20 million

Operational costs (annual)

Unknown

Duration of project construction/installation

The entire project development process (including construction) is expected to take 3-4 years. Under the current schedule, turbine commissioning is planned for November 2007.

Comparison of actual costs with expected costs

Unknown

Initial funding source(s)

- Grant funding (Focus on Energy).
- EcoEnergy LLC investment.

Ongoing funding source(s)

- Revenues from electricity sales under negotiated PPA.

Federal/state/local/utility incentives facilitating development of the project

- The project has received a $6,000 grant from Focus on Energy for the feasibility study, and may seek additional grant funding from Focus on Energy of $40,000 per turbine.

Wind resource

6.7 m/s annual wind average at 80m hub height (40 year annualized average).

Utility buy-back rate (if applicable)

Not yet determined.

Rate of return

Not yet determined.

Payback

Not yet determined.

Description of installed equipment

EcoEnergy is considering Vestas V-82 turbines for the project. Project may consist of six 1.65 MW turbines or four 2.5 MW turbines.

Other technologies considered

Unknown.

Project goals

- Discussions have been held with MG&E regarding purchasing power from the project for its clean power program, locking in a fixed price for power through a 20-year PPA. However, MG&E has not made a final determination the PPA.
- Landowners are interested in the investment opportunity offered by the project.

Project history

- Project was initiated by EcoEnergy LLC after MG&E announced new wind tariff.
- Project was one of few sites with good potential in Dane County, and landowners were familiar with wind power investment opportunities through conversations with other developers.

Obstacles encountered and addressed

- Project was determined not to be feasible under MG&E's standard wind tariff, but parties were able to work out a preliminary agreement under a negotiated PPA (with final price yet to be determined based on final project financing arrangement).

Regulatory hurdles

- FAA permit review process has slowed down considerably in recent months.

Cash flow analysis: flip model

Using similar assumptions as those that were employed for the multiple local owner cash flow analysis, for the flip structure we modeled a sample 1,500 kW project with a capacity factor of 28 percent[‡‡], an installed cost of $2,250 per kW, and annual O&M costs of 3 percent of the installed project cost, increasing at 2 percent per year. As the ownership structure for the

‡‡ As previously noted, this capacity factor is at the high end of the range that would be expected in Wisconsin.

EcoDane project was used as a model for this analysis, we assumed that project ownership is shared between three parties: the tax-motivated investor (a C-corporation), a local investor LLC, and the project developer. Revenues and annual expenses are shared between the parties in accordance with their respective ownership shares. The C-corporation has a 90 percent ownership share for the first 10 years of the project, and maintains a 10 percent ownership share for the last 10 years in accordance with current IRS guidance. The local investor LLC has a 5 percent ownership share for the first 10 years, a 70 percent share for the last 10 years, and finances 50 percent of its investment with a commercial bank loan at 11.25 percent interest (Prime + 3). The developer has a 5 percent ownership share for the first 10 years, a 20 percent share for the last 10 years, and receives a management fee of $15,000 per year from the C-corporation for the first 10 years of the project.

Electricity produced by the project is sold under a 20-year PPA at the starting rate of 6.5 cents per kWh, increasing 2 percent annually. Construction expenses are incurred in Year 0, and all operating revenues and expenses (including loan interest and principal payments) are incurred beginning in Year 1. For each party, the combined state and federal income tax rate is assumed to be 40 percent. We used a 10 percent discount rate for the net present value (NPV) calculations.

The figures below present the post-tax annual and cumulative cash flows for each party.

Figure 2-3. Annual cash flow for C-corporation, flip model

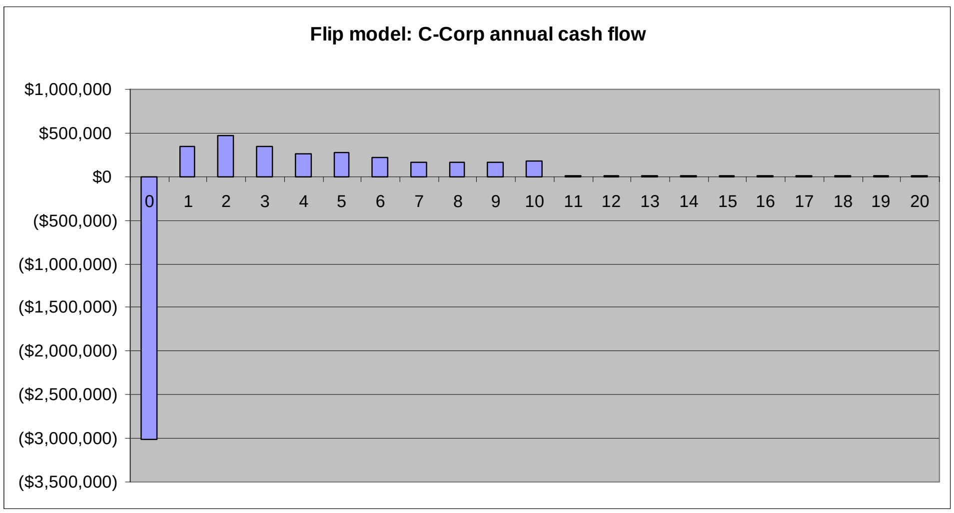


Figure 2-4. Cumulative cash flow for C-corporation, flip model

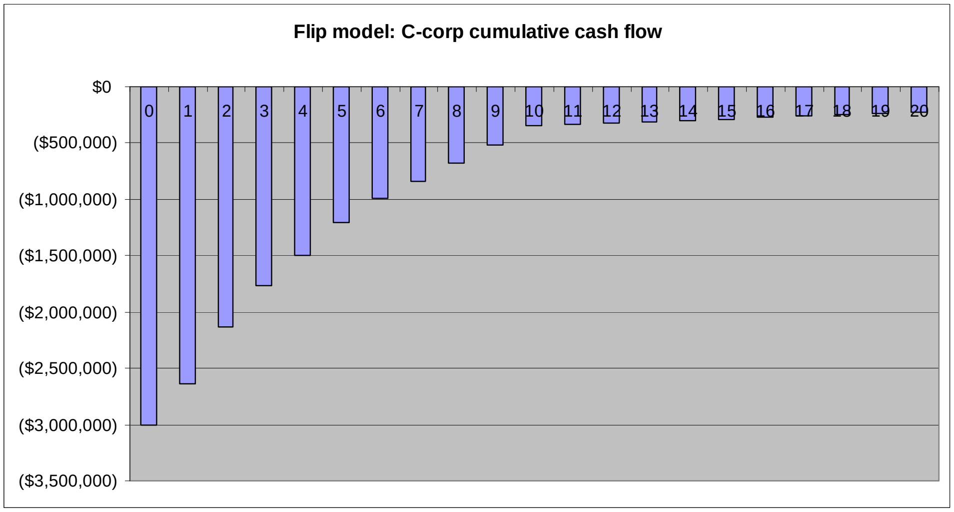


Figure 2-5. Annual cash flow for local investor LLC, flip model

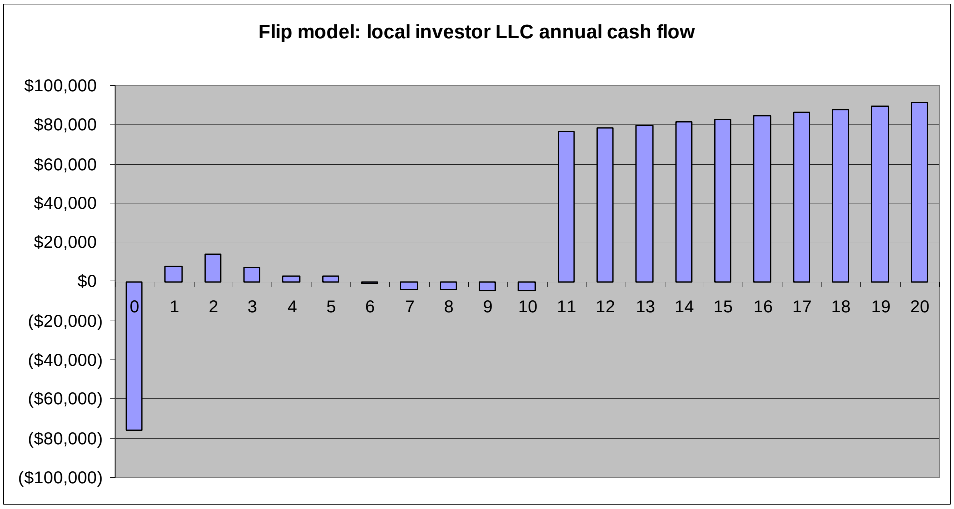


Figure 2-6. Cumulative cash flow for local investor LLC, flip model

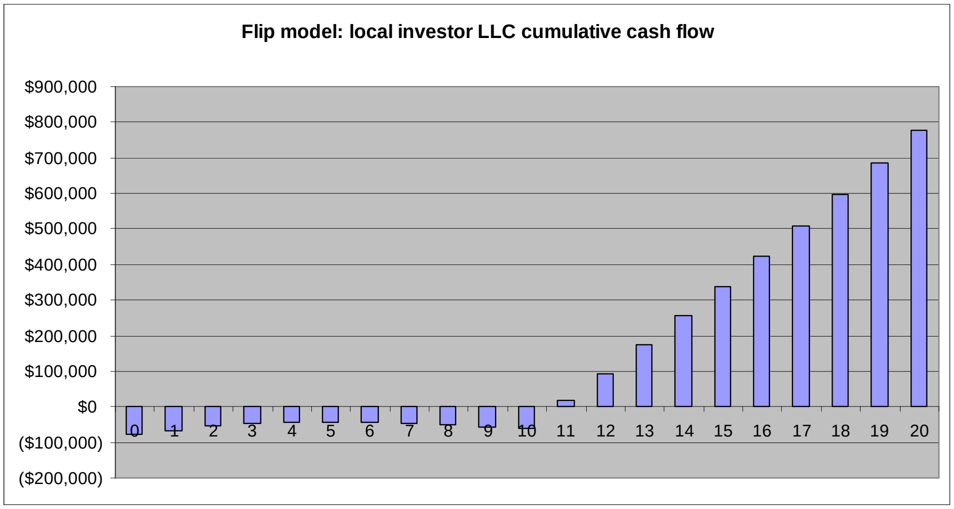


Figure 2-7. Annual cash flow for project developer, flip model

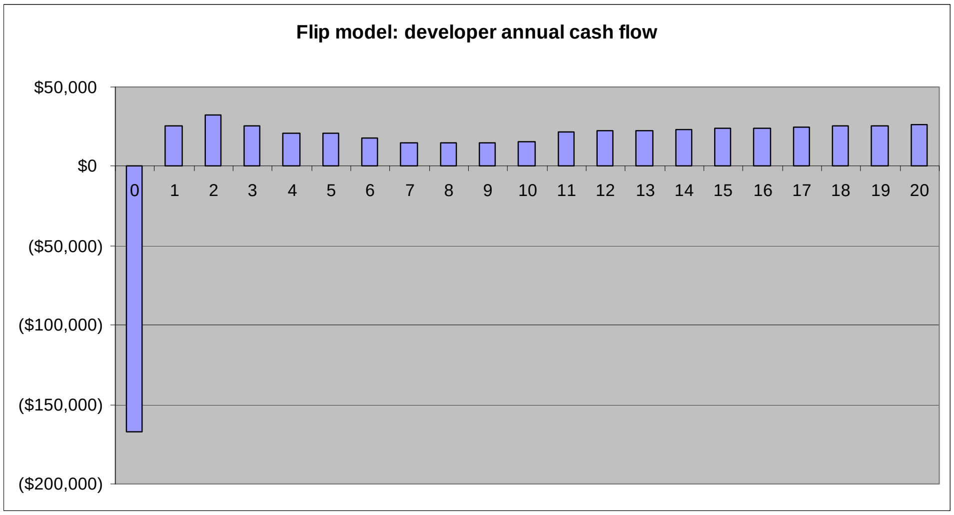
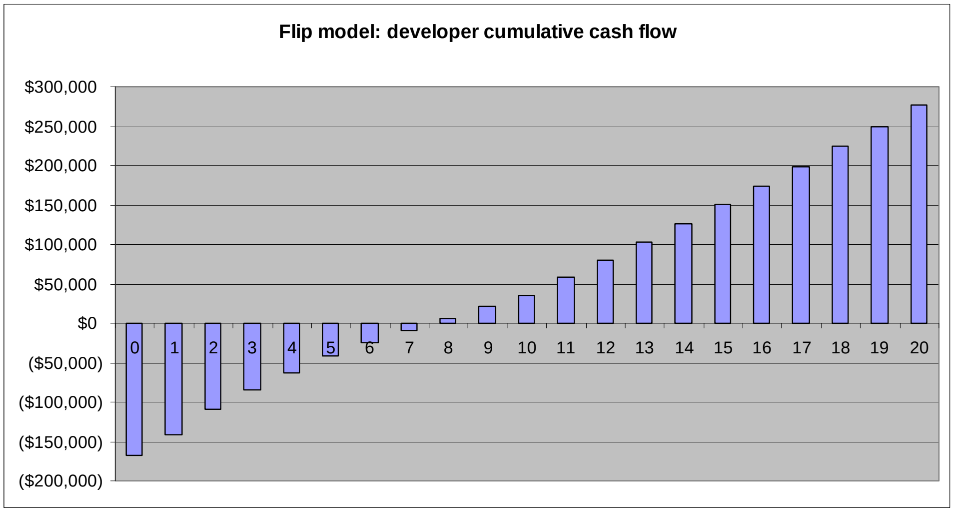


Figure 2-8. Cumulative cash flow for project developer, flip model



As we saw with the multiple local owner model cash flow analysis, the underlying assumptions used in this analysis do not produce an economically viable result for all parties. For the C-corporation (which bears the majority of the project's up-front costs), positive cumulative cash flow (payback) is not achieved within the 21-year timeframe, the NPV of the annual cash flow for Years 0 through 10 and Years 0 through 20 is negative, the 11-year IRR is -3 percent, and the 21-year IRR is -1.5 percent.

Because they bear a minimal fraction of the up-front costs, the flip model performs better for the local investor LLC and the project developer. Under the original assumptions, the local investor LLC achieves payback in Year 11 and a 21-year IRR of 19 percent. The NPV of the local investor LLC's annual cash flow for Years 0 through 10 is -$48,000, and the NPV of the annual cash flow for Years 0 through 20 is $116,000. The developer achieves payback in Year 8, an 11-year IRR of 4 percent, and a 21-year IRR of 12 percent. The NPV of the developer's annual cash flow for Years 0 through 10 is -$31,000, and the NPV of the annual cash flow for Years 0 through 20 is $15,800.

As noted previously, this cash flow analysis reflects a more complex ownership structure than the basic flip model, as it involves an ongoing role for the project developer, as is the case with the planned EcoDane project. We also ran the analysis under a simplified ownership structure that leaves the developer out of the equation, sharing project ownership between the C-corporation (90 percent for the first 10 years and 10 percent for the last 10 years) and the local investor LLC (10 percent for the first 10 years and 90 percent for the last 10 years). However, this model is still not financially viable for the C-corporation. Decreasing the magnitude of the C-corporation's ownership share and increasing the magnitude of the local investor LLC's ownership share improves the results for the C-corporation, but makes the model unviable for the local investor LLC.

2.3. Consumer cooperative model

A cooperative is a member-owned, democratically-governed enterprise that provides goods or services for the exclusive benefit of its members. On an annual basis, any profits generated by the cooperative are typically distributed to members in the form of a dividend. The amount of the dividend is usage-based—i.e., based on the amount of business each member has conducted with the cooperative, rather than by their level of investment (Bolinger 2001).

As noted by Bolinger et. al. (2004), community wind is often referred to as a “cooperative” business model, and although community wind projects involving multiple investors may benefit from a cooperative management approach (i.e., the one-vote per investor approach employed by the Minwind LLCs), community wind projects in the United States are not typically structured as legally-defined cooperatives. According to Bolinger et. al. (2004), community wind projects would be most likely structured as consumer cooperatives, where the members consume the power produced by the project. Energy produced by the consumer cooperative may either be delivered directly to members for their consumption (which would require a competitive market for electric service provision), or netted against members’ power consumption in cases where cooperatives have established such an arrangement with the retail electric service provider. Under the netting scenario, the cooperative establishes a PPA with the utility, and at the end of the year (or more frequently if desired) the wind project’s output is netted against the co-op members’ electricity consumption. This arrangement requires that all cooperative members be within the service territory of the partner utility (Bolinger 2001).

As described in Bolinger et. al. (2004), cooperative ownership of wind projects is fairly rare, especially in the United States where a number of factors make this model complex and uncompetitive. Sweden is one of the few countries where true cooperatives have generated a substantial amount of wind development. Before the residential electric service market was opened to competition, the success of the model in Sweden was largely due to utility support for aggregated net billing arrangements (Bolinger 2001).[§§]

According to modeling conducted by Bolinger et. al. in the 2004 study (which incorporated some Oregon-specific parameters), aggregated net metering was actually the most financially competitive ownership structure of the seven structures they examined, producing the highest revenue surplus in terms of $/MWh. However, Bolinger et. al. discounted the viability of the aggregated net metering model due to the regulatory and institutional barriers associated with implementing aggregated net billing in the United States.[***] The study concludes that cooperative ownership is not likely to be a competitive business model for community wind projects in Oregon or elsewhere in the United States due to the substantial hurdles with implementing such a model.

Disadvantages of the cooperative ownership model include:

- Federal law limits allowable rates of return on investments in cooperatives, impeding the model’s ability to attract outside investment (Myers and Deisinger 2005).

§§ Since deregulation and associated drops in the price of feed-in tariffs, partnerships between local utilities and cooperatives have become less financially viable in Sweden. However, deregulation has spawned a new nationwide cooperative model, where Sveriges Vindkraftkooperativ has partnered with a nationwide distribution company which provides “balance of service” to cooperative members (Bolinger 2001).

*** In the few cases where regulatory bodies in the U.S. have made stipulations for aggregated net metering, such arrangements have pertained to the aggregation of multiple meters owned by a single entity. In Pennsylvania, new net metering rules allow small businesses to combine separate meters used within a single operation, which is for the “primary benefit of commonly owned and operated farming operations” (Pennsylvania Public Utilities Commission (June 22, 2006). Available at: http://www.puc.state.pa.us/general/press_releases/press_releases.aspx?ShowPR=1569). In Vermont and California, farms are also allowed to aggregate multiple metered accounts against production by biogas systems (Bolinger 2004).

- It may be difficult for cooperatively-owned wind projects to capture the value of federal tax incentives such as the PTC and accelerated depreciation either because they have no tax liability as non-profit corporations (and individual members are unlikely to have sufficient passive tax liability themselves), or because power consumption by co-op members conflicts with the PTC's requirement that power be sold to an unrelated third party (Bolinger et. al. 2004).
- In the absence of retail choice for electric service provision, transferring the power produced by the cooperative requires utility cooperation for the aggregated net billing arrangement (Bolinger 2001). Even if the utility supports such an arrangement in theory, it may be technically difficult to achieve under its existing billing system (see WindShare case study).
- As described by Bolinger (2001), cooperatives face several obstacles in terms of raising sufficient capital to finance wind projects:
  - Because the annual dividend payment depends on the amount of power consumed by a member, if a member's power consumption is less than the amount of his investment, the member does not recoup the full value of the investment. This creates an incentive for under-investment on the part of cooperative members.
  - Businesses are unlikely to invest in cooperatives because inexpensive power increases taxable profits.
  - In the case of aggregated net billing arrangements, the universe of potential cooperative members is limited by utility service territories. And as turbine technology improves (thus increasing output), cooperatives would need to enlist even more members to ensure that members' power consumption is greater than the project's electricity production. Otherwise members are unable to recoup the full value of their investment.

The experiences of the Toronto Renewable Energy Cooperative (TREC) highlight the potential difficulties surrounding implementation of aggregated net billing and other challenges facing the consumer cooperative model. TREC's WindShare project installed the first utility-scale wind turbine in an urban setting in North America. Under the project's original business plan, TREC intended to pursue an aggregated net billing arrangement with Toronto Hydro, the purchaser of WindShare's electric output. Though the utility was open to considering the arrangement, thus far a number of factors have prevented the plan from becoming a reality (see WindShare case study). As described by Bolinger et. al. (2004) and Bolinger (2001), aggregated net billing for the WindShare project has met the following obstacles: (1) The Ontario Energy Board ruled that under such an arrangement, member dividends would be based on the generation price rather than the full retail rate, and members would be required to pay for transmission costs, significantly impacting the expected financial returns from the arrangement; (2) tax consultants advised TREC that electric bill savings would likely be considered taxable income; and (3) Toronto Hydro found it would need to implement an expensive upgrade to its billing system in order to accommodate aggregated net billing. To date, TREC relies on a standard power purchase arrangement between the cooperative and Toronto Hydro, and cooperative members receive dividends from the project which are considered taxable income (Bolinger 2001).

Case study: WindShare

As discussed above, the TREC WindShare project is one of the few wind projects in North America that employs a cooperative ownership structure. It was also the first project to install utility-scale turbines in an urban environment.

Project Name

WindShare

Business Model Type

Consumer cooperative

Location

Toronto, Ontario, Canada

Utility

Toronto Hydro

Case study references

- Mark Bolinger, Ryan Wiser, Tom Wind, Dan Juhl, Robert Grace (July 2004). *A Comparative Analysis of Community Wind Power Development Options in Oregon*. Available at: http://www.cleanenergystates.org/library/Reports/OR_Community_Wind_Report.pdf.
- WindShare web site. Available at: http://www.trec.on.ca/windshare/index.html.
- WindShare (June 15, 2002). *Offering Statement*. Available at: http://www.trec.on.ca/windshare/about.html.

Project ownership/management structure

- The first turbine is jointly owned (50/50) by the WindShare cooperative and Toronto Hydro. The parties are jointly responsible for project development, capital costs, and operations and maintenance.
- Co-op members must purchase 1 Membership Share (limit of 1 per household) for Cdn$1, which entitles the purchaser to one vote in the cooperative and 5 Preference Shares (limit of 50 in 5-share increments) at a cost of Cdn$100 each, which entitles the purchaser to a share of project dividends. Purchasers must be Toronto residents.
- 8,000 preference shares for the first turbine were sold before the first Exhibition Place turbine was completed.
- Under the terms of the joint venture between Toronto Hydro and WindShare, each party is entitled to half of the turbine's electric output. WindShare entered into a three-year power purchase agreement to sell its share of the power to Toronto Hydro, which retails the power to its customers as "green energy." (Renewable energy attributes are sold to Toronto Hydro along with the power.)
- Each year WindShare members earn an annual financial dividend from the sale of the electricity to Toronto Hydro, minus the cooperative's annual expenses for operating its share of the turbine.
- WindShare is still pursuing an aggregated net billing arrangement under which its share of the electricity produced would be netted against co-op members' electric bills.

Project siting and metering

The installed turbine is centrally-located on the utility side of the meter at Exhibition Place on the Toronto waterfront. An additional turbine is in the pre-development planning stages but appears to have been stalled since 2003.

Key stakeholders

- Toronto Renewable Energy Co-operative, Inc., which manages the project on behalf of the joint venture.
- Toronto Hydro, which owns a 50% share in the turbine, purchases 100% of the co-op's share of electricity production, and owns the distribution network which transfers the power to end users.
- WindShare cooperative members, who have invested in the project and receive annual dividends from the sale of power.

Capital & installation costs

Operational costs (annual)

Cdn$1,600,000 (ExPlace turbine only).	Between Cdn$46,000-$55,000 per year (based on *Offering Statement* estimates for first 4 years of the project).

Duration of project construction/installation

December 2002 to January 2003.

Comparison of actual costs with expected costs

The WindShare *Offering Statement* anticipated that its 50% share of the cost of the two planned turbines would be Cdn$1,700,000, indicating that the cost of the single installed turbine at Exhibition Place was within expectations.

Initial funding source(s)

The financing structure for turbine installation as set forth in the *Offering Statement* is:

- Member equity from sale of shares: Cdn$1,055,000
- Forgivable loan from the Canadian government: Cdn$150,000
- Bridge financing from the Toronto Atmospheric Fund: Cdn$495,000

Ongoing funding source(s)

The *Offering Statement* anticipates annual revenue (mainly from power sales) to be:

- Year 0: Cdn$9,283
- Year 1: Cdn$138,054
- Year 2: Cdn$168,646
- Year 3: Cdn$175,631

Federal/state/local/utility incentives facilitating development of the project

- Pre-development work was funded by government grants.

kWh (annual output for ExPlace turbine)	**Capacity factor**
1,400,000 kWh	21%
Utility buy-back rate (if applicable)	**Rate of return**
Unknown	Unknown

Payback

Unknown

Description of installed equipment

Lagerwey Windmaster B.V. (a Dutch company) supplied the 750 kW, direct drive, model LW 52 wind turbine.

Other technologies considered

Unknown

Were any technical problems encountered, and if so, how were they addressed?

Unknown

Project goals

- Promote community-based renewable energy development under newly deregulated electricity marketplace.
- Demonstrate the opportunity for utility-scale wind projects in urban environments as a solution to smog and global climate change.

Project history

- In 1998, members of a neighborhood-based environmental group, the North Toronto Green Community, were interested in promoting development of community-based renewable energy in Toronto.
- The group formed the Toronto Renewable Energy Cooperative with grant support from the Toronto Atmospheric Fund, and developed the original project proposal for a community-owned wind turbine located along Toronto's Lake Ontario waterfront.
- TREC established the WindShare project in 1999, and a joint venture with Toronto Hydro Energy Services was established to undertake project development.

Utility or government program initiating the project

NA

Role played by the electric utility

Toronto Hydro is an equal partner in the project and purchases 50 percent of the turbine's output under the terms of a PPA, receiving the remaining 50 percent through its ownership share.

Obstacles encountered and addressed

The original plan for aggregated net metering met a number of hurdles, including the technical inability of Toronto Hydro to implement the system without an expensive billing system upgrade. The cooperative instead sells its power to Toronto Hydro under a standard power purchase agreement and members receive annual dividends based on net revenues from electricity sales.

Regulatory hurdles

Two key factors impaired the anticipated profitability of the project which was based on the expectation that an aggregated net billing arrangement with Toronto Hydro would provide the vehicle for transferring power from the project to coop members:

- Net metering on customer-sited renewable applications usually means that the customer receives the full retail value of the generated power. But the Ontario Energy Board ruled that coop members were only entitled to the generation price, rather than the full retail rate.
- Tax advice received by the project determined that under an aggregated net metering arrangement, utility bill savings were likely to be considered taxable income (which is not usually the case with individual net metering), decreasing the expected profitability of the project.

2.4. Municipal ownership model

Another model evaluated in Bolinger et. al. (2004) is the municipal ownership model, where a town-owned wind project either produces power that is sold to an unrelated third party, or produces behind-the-meter power to offset energy usage at public facilities such as schools.

(This model does not include wind projects owned by municipal utilities to produce energy sold directly to end-use customers.)

A number of schools in Iowa and other Midwestern states have installed behind-the-meter projects, in most cases made possible with the support of substantial grants and/or no- or low-interest loans (Galluzzo and Osterberg 2006). Since 2003, the Massachusetts Technology Collaborative (MTC) has supported the development of municipal wind projects in Massachusetts through its Community Wind Collaborative. In part, MTC has pursued the municipal ownership model because such projects may be too small to attract a commercial developer and because community wind is viewed as a less contentious approach to renewable energy development than highly controversial commercial projects like the 420 MW offshore Cape Wind project (Bolinger et. al. 2004).

MTC's Community Wind Collaborative provides cost-free pre-development technical assistance (including wind monitoring equipment and data analysis services) to municipalities interested in wind development. The program only serves municipalities whose residents are part of IOU service territories, and has been very popular with towns across the state. Most program participants are interested in exploring the potential for behind-the-meter applications, and there is currently a long queue of potential projects seeking program resources. At the same time, no projects have actually been constructed to date. (See sidebar, *MTC's Community Wind Collaborative*).

- Potential advantages of the municipal ownership model include:
  - If sited on town-owned land, the project may be exempt from lease or property tax payments (Bolinger et. al. 2004).
  - Project may be able to access low-cost financing with municipal bonds, but according to Bolinger et. al. (2004), it is likely that use of municipal bonds will only be allowable for behind-the-meter projects, and would not be accessible for projects that generate revenue from the sale of power to a third party.
- Potential disadvantages of the municipal ownership model include:
  - Municipalities may not be legally permitted to provide equity investment for wind projects (Bolinger et. al. 2004).
  - Economic benefits for town residents are likely small as they are not investing directly in the project. According to Bolinger et. al., (2004), there could be indirect benefits to town residents such as reduced municipal tax payments or increased municipal services, provided the project generated sufficient revenue for the town.
  - The dynamics of town politics may make the development of a community wind project even more challenging.

MTC's Community Wind Collaborative

One of the goals of the program is to promote the development of community-based wind projects that would serve as positive examples of wind energy development, thus potentially decreasing local opposition to future wind projects (Bolinger et. al. 2004). A failed or contentious project would be a substantial setback, so the program has proceeded cautiously with the development of potential projects. The program has not had sufficient resources to serve all of the interested communities. Also, by providing free project development services, the program competes with local wind developers who might be otherwise willing to work on community-scale projects (Michelman 2006).

MTC's Community Wind Collaborative does not stipulate which ownership/financing structures should be employed by the projects it supports, though the program manager notes that due to legal hurdles associated with municipal ownership a third party ownership model would likely be easier to implement (Goland 2006). To facilitate completion of projects participating in the program, MTC will soon be adding a Standard Financial Offer (SFO) program component. Projects (500 kW or greater) that have obtained the necessary municipal approvals and have demonstrated project viability through a completed CWC feasibility study (or equivalent analysis) will be eligible to apply for an SFO. In addition to providing qualifying projects with late-stage project development assistance, MTC will provide project financing through a REC purchase agreement.

Goland also notes that municipal projects are less likely to flounder when there is a single person with adequate authority in charge of moving the project forward. To entities considering implementing a program similar to the MTC Community Wind Collaborative, Goland recommends beginning with a few pilot projects before opening it up to a full-scale program where many municipalities are eligible to participate. In part, the pilot program approach will allow the program manager to gain a good understanding of how the general regulatory environment is likely to affect program implementation before a full-scale program is launched (Goland 2006).

This page deliberately left blank.

3. Multi-party ownership models for anaerobic digesters

Anaerobic digesters offer the potential for substantial renewable energy generating capacity as well as a number of non-energy benefits to agricultural producers and rural communities. In addition to generating renewable energy, digesters provide cost savings or new revenue streams for farmers through the sale of energy and byproducts for landscaping and livestock bedding, reduce odors from livestock operations, and provide an environmentally-preferable manure management strategy that reduces nutrient loading into lakes and streams.

The high capital costs and technical complexity of installing, operating, and maintaining anaerobic digesters create substantial barriers to widespread implementation of the technology. These barriers may be addressed through partnership models that effectively utilize the financial resources and technical expertise of multiple stakeholders. The financial viability of digester projects is also highly dependent upon herd size. According to Larry Krom of Focus on Energy (2006), the smallest herd size currently supporting an anaerobic digester in Wisconsin is 800 head, though the technology should be viable for herds as small as 450 to 500 head. The fact that the average herd size in Wisconsin is 92 head poses significant limitations to the potential for proliferation of anaerobic digester technology unless technology develops to the point where smaller systems can be economically viable.

Financial and technical barriers may be addressed through partnership models that effectively utilize the financial resources and technical expertise of multiple stakeholders, as well as partnership models that seek to improve economies of scale. In Wisconsin and other states with strong agriculture sectors, innovative partnership structures have been employed for ownership and operation of anaerobic digesters. Two of the models summarized in the *Agricultural Biogas Casebook* (Kramer 2004) have particular relevance for this study: (1) the Dairyland/Microgy joint ownership model and (2) the "community digester" model. The dual farmer/utility ownership model employed by Dairyland Power and Microgy offers an innovative approach for joint financing of capital costs and sharing risk, and is a model that has been successfully implemented in Wisconsin. The community digester model seeks to improve the financial viability of digesters through the economies of scale that are achieved by combining the waste streams of multiple farms. Several community digester feasibility studies have been conducted in Wisconsin, including a 2003 study by MG&E (MG&E 2003).

Alliant Energy Model

The *Agricultural Biogas Casebook* discusses a shared ownership model (referred to as the "Alliant Energy model") which is very similar to the Dairyland/Microgy model. In the Alliant model, the utility owns the generating equipment and the farmer owns and maintains the digester, but the digester supplier is not involved in providing project financing or ongoing O&M. As Microgy has decided not to provide financing for any additional digesters in Dairyland's service territory, Dairyland is currently investigating potential outside sources of financing for future projects, and therefore such projects may employ a business model that is closer to the Alliant model. At the same time, Alliant is no longer offering the model to its agricultural customers in Wisconsin (Krom 2006), and farmers surveyed by Kramer (2004) that were using the Alliant model expressed a preference for full ownership of the systems over shared ownership due to the higher expected financial benefits.

3.1. Dual ownership model

In this model, referred to in the *Agricultural Biogas Casebook* (Kramer 2004) as the "Dairyland/Microgy model," the utility finances and owns the electricity generating equipment and a third party (Microgy, Inc.) installs and maintains the digester. The third party installer also provides the farmer with 100 percent non-recourse financing for the digester, eliminating the farmer's personal liability for the capital-intensive equipment. Under the terms of the purchase agreement between the farmer and Dairyland, all revenues from the sale of biogas are earmarked to Microgy to pay down the debt. Microgy also provides ongoing monitoring and maintenance services to support operation of the digester. The farmer is able to use the separated solids as high-quality bedding material for the herd, which can save around $80,000 per year for a 1,000-head herd, minus the minimal operational expenses for the separator (Hildebrandt 2006). The liquid output from the separator can be applied to fields as fertilizer.

- Advantages of the dual ownership model include:
  - Leverages utility expertise in installing generating equipment, and supplier/installer expertise in operating digester.
  - Provides utility with source of renewable energy and distributed generation capacity.
  - Entails minimal up-front costs for farmer, minimizes farmer's ongoing financial risks, and has a low "hassle factor."
- Disadvantages of the dual ownership model include:
  - Provides lower financial returns to the farmer (than if the farmer were the full owner of the system (Kramer 2004). In the early years of the project while the digester debt is being paid off, the farmer's main benefits are in the form of avoided costs for bedding, fertilizer, and pesticides.
  - Utility retains risks associated with customer-sited systems.
  - Utility may not be as motivated to address maintenance issues quickly compared with a farmer who has full system ownership (Krom 2006).

Though Microgy is not currently providing project financing under the Dairyland/Microgy model, according to Mike Casper the company believes the model is still a good one for selling digesters, plus the company gets the added value of providing ongoing O&M services (Casper 2006). If project economics are favorable enough (i.e., a high enough power purchase price (8-10¢/kWh) locked in under a long-term agreement, sufficient additional revenues through the sale of carbon credits, and lowered operating expenses), the company would reevaluate the model. In addition, Microgy is considering a third party ownership model where the company would own the digester and the gas cleanup systems, selling the biogas to a utility or industrial end user. However, this model is only under consideration for large-scale farms (5,000 head or more) in California.

The following case study describes the Dairyland/Microgy model employed for three Wisconsin digester projects.

Case study: Dairyland/Microgy model

Project Name	**Business Model Type**
Dairyland/Microgy anaerobic digester	Shared ownership, financing, and O&M
Location	**Electric Service Provider**
This model was used for the installation of anaerobic digesters at several dairies in Western Wisconsin	Dairyland Power Cooperative

Case study references

- Neil Kennebeck, Director of Planning Services, Dairyland Power (November 15, 2006). Personal communication.
- Mike Casper, Microgy (December 4, 2006). Personal communication.
- Joseph Kramer, Resource Strategies, Inc. (September 2004). *Agricultural Biogas Casebook*. Available at: http://www.cglg.org/biomass/pub/AgriculturalBiogasCasebook.pdf

Project ownership/management structure

This model is essentially a three-way partnership between the utility, the digester supplier, and the farmer. Dairyland Power Cooperative finances and owns the generation equipment and the farmer owns the anaerobic digester. Microgy Inc. designs and installs the anaerobic digester, and provides 100% non-recourse financing for the digester purchase. Microgy also provides ongoing maintenance for the digester and generating equipment. Under the biogas purchase agreement between the farmer and Dairyland, all sales revenues are assigned to Microgy to service the debt on the digester.

Project siting and metering

Project is sited on-farm; interconnected on the utility side of the meter.

Factors in ensuring project success

- Dairyland conducted screening to determine best farms where the model could be implemented. Screening criteria included a size target of 1,000 head, and an assessment of the farm's business plan and financial health.
- They have achieved good results with adding substrates to the digester to increase methane production (1 part substrate to 9 parts manure). They use sludges from waste oil processing that would normally be landfilled, so it is an inexpensive substrate that can as much as double methane production and lower the cost per kWh significantly.

Key stakeholders

- Farmer
- Dairyland Power Cooperative
- Microgy

Capital & installation costs

Est. $3 to $3.5 million

O&M costs

Kennebeck estimates the current operating costs are around 6 or 7¢/kWh, but he notes that O&M costs have been dropping and the goal is to achieve 5¢/kWh.

Duration of project construction/installation

Unknown

Initial funding sources

- USDA grants

- Project financing by Microgy

Ongoing funding sources

- Biogas sales to Dairyland
- Projects are in the process of getting certified for the sale of carbon credits through the Chicago Climate Exchange

Federal/state/local/utility incentives facilitating development of the project

All projects received grants from the U.S. Department of Agriculture. Dairyland Power completed the grant applications, and funds were provided to the farmer.

kW

750 kW (net) or 800 kW (net) depending on engine generator set (see "installed equipment" below)

kWh

Unknown

Payback

As the financing agreement is between the farmer and Microgy, Kennebeck was unable to specify the payback period, but estimates payback is likely to be between 10-12 years. A payback period of 10 years was cited by Kramer (2004).

Description of installed equipment

- All farms have a Microgy-designed complete-mix tank digester with 750,000 gallon tank.
- Two farms with Waukesha engine generator sets have a gross capacity of 775 kW and a net capacity of 750 kW.
- One farm with the Jenbacher engine generator set has an 848 kW gross capacity and 800 kW net. Kennebeck noted that the Jenbacher engine is more efficient than the Waukesha engine generator set.

Other technologies considered

Kennebeck noted that due to its higher efficiency, they would use the Jenbacher engine over the Waukesha engine for future projects. They are also looking into technologies that would decrease capital costs, such as smaller, modular digester technologies.

Project goals

- Dairyland's goal is to promote projects that benefit farms. Nutrient management is a big issue on large operations, and anaerobic digesters are a tool to address that issue. Benefits include odor reduction, fewer flies, weed seed elimination which allows reduction in pesticides. Digested solids can also be used to produce an alternate bedding material which, if properly managed, has been found to have little to no impact on herd health.
- The model also allows Dairyland to increase its use of renewable energy and provides distributed generation.

Project history

- Microgy conducted research on the location of confined feeding operations on the DNR web site and approached Dairyland.
- Dairyland conducted the screening process to identify potential farms where the model could succeed.
- Dairyland, Microgy, and the farmers worked together to develop the project plans.

Challenges to implementing the model

- Economies of scale are very important to these types of projects. Interconnection has high costs that are the same no matter how big or small the project is.
- One reason that O&M costs are so high is that the digester requires frequent monitoring to ensure proper conditions for the anaerobes.
- Capital costs have increased for these types of projects (costs for labor, steel, and other raw materials have increased) as utilities are currently in a building cycle.

Replicability

- Since implementing the first three projects, Microgy has decided not to continue to provide project financing. Dairyland is currently looking into alternative ownership/financing structures, including outside companies that would own both the digester and generating equipment (GE or similar company).
- Dairyland has looked into implementing a centralized digester model that would serve a number of smaller farms, but this approach can require some difficult coordination between stakeholders.

Cash flow analysis: dual ownership model

The cash flow model for the anaerobic digester dual ownership structure was based on the following assumptions: installed capacity of 848 kW; capacity factor of 90 percent; and an installed system cost of $3,000,000, with $1.5 million for digester design, engineering, and installation, and $1.5 million for the engine generator. For the farmer-owned digester, grant funding totals $280,000, with USDA Section 9006 grants providing $200,000 and state Focus on Energy grants providing $80,000. The sale of carbon credits provides an additional one-time payment of $10,000 in Year 1. The remaining capital for the digester ($1,210,000) is financed by the manufacturer/installer in the form of a 10-year non-recourse loan at 11.15 percent interest. We used a 10 percent discount rate for the NPV calculations.

The utility purchases biogas from the project under a 20-year agreement at a purchase price that is equivalent to 6 cents/kWh, with revenues increasing 2 percent annually.[†††] O&M costs begin at 5 cents/kWh increasing 2 percent annually. An avoided bedding cost of $80,000 per year is also included in the cash flow analysis. The combined state and federal income tax rate is assumed to be 40 percent. The utility-owned generating equipment was not included in the cash flow analysis.

††† Though this cash flow model is based on the Dairyland/Microgy digester model, Dairyland's actual biogas purchase price is unknown.

As shown in the figures below, the project achieves a positive cumulative cash flow (payback) in Year 12. Annual cash flows become positive in Year 11 after the 10-year equipment loan is paid off. The NPV of the post-tax annual cash flow for Years 0 through 10 is -$123,000 and the NPV of the post-tax annual cash flow for Years 0 through 20 is $214,000. The 21-year IRR is 20 percent.

Figure 3-1. Annual cash flow, dual digester ownership model

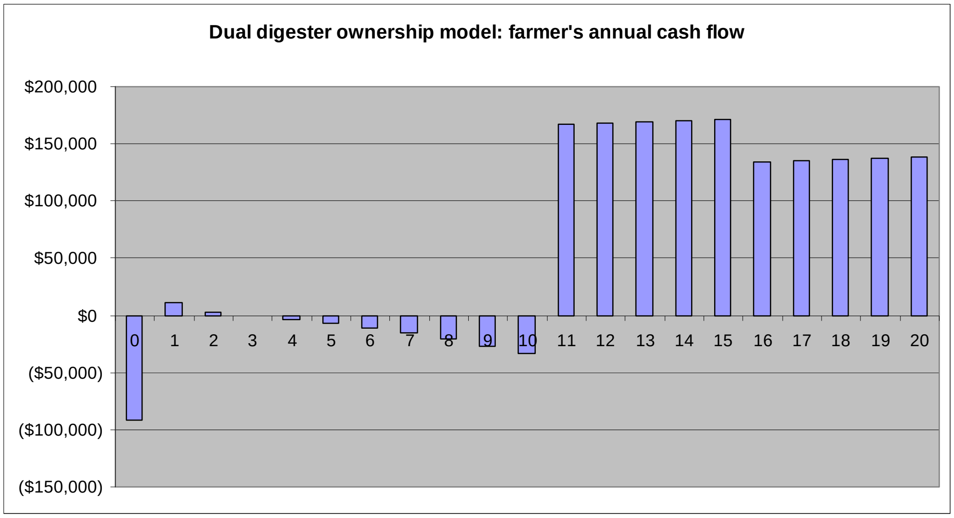
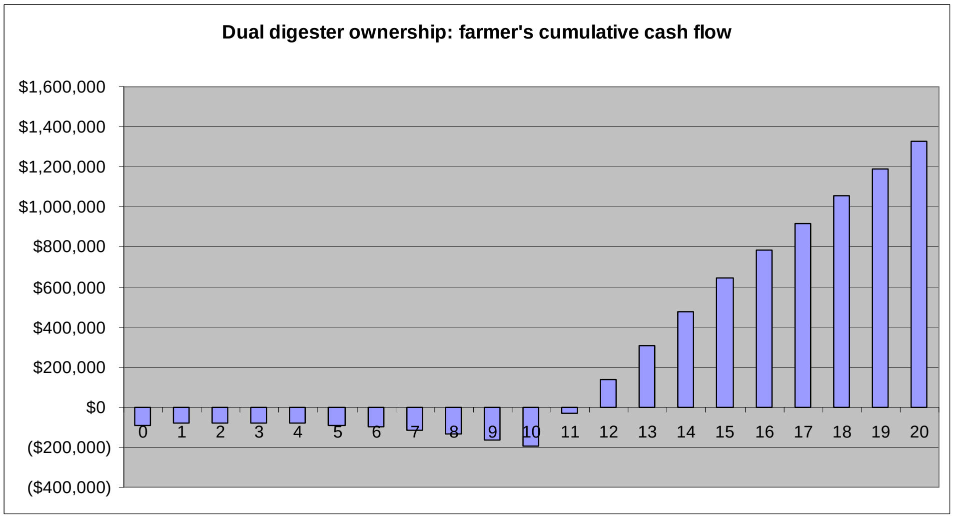


Figure 3-2. Cumulative cash flow, dual digester ownership model



The viability of the model is highly dependent upon O&M costs and the power purchase price. The Dairyland/Microgy O&M costs are currently above 6 cents per kWh, though they believe 5 cents per kWh is achievable. If O&M costs of 6.5 cents per kWh are used in the model, the project is no longer financially viable.

3.2. Community digester model

The community digester model seeks to take advantage of economies of scale by processing the manure waste streams of multiple farms at a centrally-located shared facility. According to the RFP recently issued by Dane County for a manure management feasibility study, there are a variety of possible ownership structures that could be employed under the community digester model, including ownership by a single farmer, cooperative ownership by a group of farmers, third party ownership (by a company like GE or Microgy), and government ownership (Dane County 2006).

- Advantages of the community digester model include:
  - Increased economies of scale may improve financial viability of digester operation.
  - Offers low financial risk for individual farmers.
- Disadvantages of the community digester model include:
  - Does not typically provide a substantial revenue stream for farmers (though it can serve as a cost-effective manure management strategy).
  - Hauling fees can dramatically impact the project's financial viability.
  - Stakeholder coordination may be challenging and time-consuming.

The Hooley Digester at the Port of Tillamook Bay was one of the first community digester projects to become operational. It is a public facility owned by the Port of Tillamook Bay, and additional details on the project are provided in the following case study.

Case study: Hooley Digester, Port of Tillamook Bay

Project Name	**Business Model Type**
Hooley Digester	"Community" digester – shared facility under public ownership
Location	**Utility**
Tillamook, Oregon	Tillamook People's Utility District

Case study references

- Jack Crider, General Manager, Port of Tillamook Bay (December 11, 2006). Email communication.
- George DeVore, Digester Operator, Port of Tillamook Bay (November 15, 2006). Personal communication.
- George DeVore (April 2006). "Tillamook, Oregon Methane Energy Development Program." *Proceedings of the 2006 AgSTAR National Conference*. Available at: http://www.epa.gov/agstar/pdf/conf06/devore.pdf.
- Port of Tillamook Bay, Web site, "Bio-Gas Methane Facility, Hooley Digester." Available at: http://www.potb.org/methane-energy.htm.
- Joseph Kramer (September 2004). *Agricultural Biogas Casebook*. Available at: http://www.cglg.org/biomass/pub/AgriculturalBiogasCasebook.pdf.

Project ownership/management structure

Digester is publicly owned and operated by the Port of Tillamook Bay (POTB) and accepts manure from

8 nearby farms.

Project siting and metering

Located at facilities owned by the Port of Tillamook Bay, interconnected on utility side of the meter.

Factors ensuring project success

- Determining ways to lower transportation costs.
- Developing effective marketing strategies for products produced.
- Flexible, adaptive approach to addressing problems encountered during the process.
- Pursuit of multiple different revenue sources to provide ongoing funding for the project (electricity sales, dry fiber bedding sales, fertilizer sales, green tag and carbon credit sales, etc.).

Key stakeholders

- Port of Tillamook Bay: Initiated the Methane Energy and Agricultural Development (MEAD) project; owns and manages the Hooley digester.
- Tillamook Soil & Water Conservation District: Administers the MEAD revolving loan fund that provides funding support to farmers and digester projects.
- Tillamook Peoples Utility District: partner in the MEAD project, purchases power produced by the Hooley digester.
- Tillamook County Creamery Association (farmer-owned cooperative): though not an official MEAD project partner, some members have been involved in the project.

Capital & installation costs

$3 million

Operational costs (annual)

$400,000

Duration of project construction/installation

August 2002-November 2003

Comparison of actual costs with expected costs

- Construction costs were within budget.
- In first year, project was expected to produce profit of $16,000; actually incurred loss of $122,000.

Initial funding sources

- DOE grant of $1.7 million
- POTB cash payment of $500,000
- POTB loan of $300,000
- Tax credits of $120,000

Ongoing funding source(s)

- Revenue from electricity sales (4.2¢/kWh) to Tillamook PUD—$63,000
- Revenue from green tag sales (0.5¢/kWh) to Bonneville Environmental Foundation)—$7,500
- Revenue from sale of dry fiber bedding—$120,000
- Revenue from tipping fees—$120,000

- Revenue from sale of compost (intermediary product when digester not running properly) and CO_2 credits (Chicago Climate Exchange through Environmental Credit Corp)—$90,000

Federal/state/local/utility incentives facilitating development of the project

- DOE grant of $1.7 million
- Oregon Department of Energy grants

kW	**kWh**
300 kW (gross) – net is close to that, but they only need max of 238 kW of capacity at max	1.5 million
Utility buy-back rate (if applicable)	**Rate of return**
4.2¢/kWh	Unknown

Description of installed equipment

- Plug flow digester by RMC with 4 400,000 gallon tanks (only 3 are in use right now)
- 2 Caterpillar 3406 200 kW generators
- Engines by Martin Machinery

Were any technical problems encountered, and if so, how were they addressed?

- Excess moisture in manure has been a problem due to amount of rainfall (100+ inches of rain a year). They need 14% solids and they are lucky if they get 10%.
- Higher than expected transportation costs – farmers now pay 80% of haul costs.
- Gas piping is too small and will need upgrade.

Project goals

- Prove the manure management benefits of digester technology to local farmers and regulatory agencies, processing 100 percent of all manure waste in the County. (Manure management is particularly critical for Tillamook County due to large concentration of dairies, over 100 inches of rain a year, and proximity to the Pacific Ocean).
- Expose financial/regulatory unknowns that similar projects are likely to encounter.

Project history

- Project took 14 years to be built.
- Original vision was for single large centrally-located facility that would accept waste from the county's 30,000 cows. Project was stymied by:
    - High transportation costs for shipping manure to central facility.
    - Large debt service that would have been required.
    - High fees for participating farmers.
- Single centralized digester project was abandoned in favor of multiple, smaller digesters. Two have been built that process waste from 3,000 cows (8 farmers); revenues will be used to finance construction of additional digesters in distributed network that will serve 4 to 6 farms each.

Challenges to implementing the model

- Attracting support for the project:

  - Original planned scale for the project was not cost-effective ($16 million plus transportation costs for central facility serving entire county and 30,000 cows), and committed EPA AgSTAR funds of $1.2 million were not sufficient to attract developer. No responses were received to original RFP. Project was scaled back, $1.7 million in DOE funds were committed.
  - Farmers opposed payment of tipping fees, so their support was enlisted by demonstrating real dollar benefits and making the farmers a part of the business through monthly disclosure of operating financials.
- Project cost-effectiveness:
  - Under the original business model, farmers were not required to pay any tipping fees as revenues from power and fiber sales were expected to offset transportation costs.
  - With losses of $122,000 in 2003-2004, a number of solutions have been proposed, including the institution of tipping fees (1¢/gallon), a higher buyback rate for power (6¢/kWh), and sale of carbon credits.

Though the project has encountered many obstacles and did not turn the expected profit in the first year, it has successfully demonstrated the value of digester technology, and promoted a better understanding of digester costs and benefits in the dairy industry. The project is strongly supported by the environmental community, and a strategy is in place to ensure cost-effectiveness and address remaining technical problems.

Regulatory hurdles

- Solid waste DEQ and air quality DEQ

4. Third party ownership models

In addition to considering new business models for customer-owned renewable energy generation, this report also evaluates several models for customer-sited generation under third party ownership which address barriers to deployment of renewable energy technologies. There are a variety of potential ownership entities under the third party ownership business model. In this analysis, we focus on a utility-owned model, a private sector model, and a cooperative model.

4.1. Utility ownership model

In some ways, the utility-owned model takes the next step beyond the dual-ownership models discussed in Section 3, with respect to anaerobic digesters. In this model, the utility owns, installs, and maintains the renewable energy generation equipment, and charges the customer for the renewable energy produced by the system. Though few utilities have pursued this model, it is currently under consideration at an IOU in the eastern United States (Cliburn 2006). The pioneering example of the model is the solar hot water program at Lakeland Electric, an all-electric municipal utility serving 100,000 customers in central Florida (Curry 2006). (The case study in this section describes Lakeland's program in detail.)

- Advantages of the utility ownership model include:
  - Overcomes customer barriers by reducing the "hassle factor" and providing renewable energy service without requiring substantial up-front investment, technical expertise, or ongoing maintenance on the part of the customer.
  - Utility retains the load served by the renewable systems, generating revenue instead of providing incentives for systems that will decrease revenue from energy sales.
  - Enables bulk purchases of renewable equipment which is likely to lower the per-system cost.
  - Capitalizes on utility's existing fee-for-service business model.
  - As non-utilities are prohibited from selling electricity in Wisconsin, the utility-owned model would be applicable to a wider range of renewable generating resources than the private sector- or cooperative-owned models for third party ownership (non-utilities would be restricted to providing to thermal energy services under a third party ownership model).
- Disadvantages of the utility ownership model include:
  - Utility retains risks associated with customer-sited systems, and assumes ongoing distributed equipment maintenance burden.
  - Increasing renewable generation capacity via distributed customer-sited systems will not be as cost-effective as installing centralized, large-scale renewable energy generation capacity.

Case study: Lakeland Electric solar hot water program

Project Name

Lakeland Solar Hot Water

Business Model Type

Utility-owned customer-sited

Location

Lakeland, Florida

Utility

Lakeland Electric, an electric-only municipal utility

Case study references

- American Solar Energy Society, (2003). *Utility Success Stories in Solar Water Heating*. Proceedings of the ASES 2003 Annual Meeting. Available at: http://www1.eere.energy.gov/solar/ush2o/pdfs/ases_final.pdf.
- Jeff Curry, Alternative Energy Coordinator, Lakeland Electric (November 7, 2006). Personal communication.
- Jill Cliburn, (November/December 2006). American Public Power Magazine, “Lakeland’s Solar Roofs.” Available at: http://www.appanet.org/newsletters/ppmagazinedetail.cfm?ItemNumber=17871&sn.ItemNumber=2108.
- U.S. Department of Energy, Energy Efficiency and Renewable Energy (May 2002). *Florida Sunshine – Natural Source for Heating Water*. Available at: http://www.eere.energy.gov/state_energy_program/case_study_detail_info.cfm/cs_id=4.

Project ownership/management structure

Utility owns, finances, installs and maintains the system; customer pays for energy produced under 10-year fixed-price contract with option to extend for additional 5 years. Customers accumulate credit toward the eventual purchase of the system after expiration of the contract term. To date, Lakeland has installed 57 systems, and is planning a ramp-up of the program for 2007.

Project siting and metering

Residential, customer side of the meter.

Factors ensuring project success

- Program is cost-effective: solar hot water heaters were the only measure that passed the Rate Impact Measure (RIM) test for cost-effectiveness, out of 140 conservation measures that the utility evaluated last year. The primary reason is that the program does not negatively impact utility revenues.
- Program is incredibly popular with customers as it removes the primary barriers to installation of solar hot water heaters (i.e., higher up-front cost than traditional heaters; concerns about maintaining complex and unfamiliar equipment).
- Program is aligned with existing business model of selling energy to customers.

Key stakeholders

- Residential customers
- Trade allies
- Lakeland

Capital & installation costs	**Operational costs (annual)**
$2,300 per customer (includes equipment, installation, metering). Lakeland obtained discounts for buying systems in bulk.	Unknown

Duration of project construction/installation

Unknown

Comparison of actual costs with expected costs

Unknown

Initial funding source(s)

Funding for the original program was partially provided by Lakeland and partially provided by grants from the Florida Energy Office and NREL, and received technical assistance from the Florida Solar Energy Center.

Ongoing funding source(s)

- Per-system revenues are approximately $180 per year (9¢/kWh, average production of 2,000 kWh per year).
- Though a fairly small and intermittent source of revenue, the program tracks the green tags produced by Lakeland's solar hot water systems, and periodically sells or trades them. In 2004, Lakeland sold 50 MWh of green tags for $40/MWh, working through the independent green tag marketer, Sterling Planet. Cliburn cites this sale as the first instance of a utility selling green tags produced by solar hot water heating.

Federal/state/local/utility incentives facilitating development of the program

State sales tax exemption

kWh	**kW**
On average, each system produces 2,000 kWh annually.	Lakeland views the program primarily as a demand response initiative. As a winter-peaking utility, Lakeland achieves a per-system credit for 0.7 kW of demand reduction in winter, and 0.4 kW during the summer.
Energy rate	**Rate of return**
Lakeland charges pilot program customers 9¢/kWh, which will likely be increased to 12¢/kWh for new installations in 2007.	Lakeland's annual rate of return is 7%

Payback

Less than 15 years. Payback is expected to be shorter when full-scale program rolls out in 2007 due to economies of scale.

Description of installed equipment

- Open loop system with 40-square foot flat-plate collector, direct-current pump powered by 5W PV module, 80-gallon storage tank with 4,500W heating element, and metering equipment.
- Metering: two sensors calculate the temperature difference between unheated water and the water in the storage tank, measuring total heat energy in Btus. One meter converts Btus to kWh equivalents. A second meter tracks kWh used by electric backup heating. The customer is billed for net solar energy (the difference between the two) at the solar rate under their power purchase contract.

Other technologies considered

Unknown

Were any technical problems encountered, and if so, how were they addressed?

- Originally getting the solar energy billing data to appear as a line item on the customer's bill required a manual process to input the data into the billing system, but this process has since been automated.

Program goals

- As the solar hot water program is primarily viewed as a demand response program, Lakeland was interested in exploring the potential for solar hot water to serve as site-installed distributed generation, while providing a profitable service to customers.
- The utility-owned approach was viewed as a way to generate revenue as well as overcome customer resistance to installing and maintaining a renewable technology they were unfamiliar with, and which cost more than traditional hot water heaters.

Program history

- Pilot program was launched in 1997 to determine whether solar energy could be metered accurately and sold profitably.
- 57 systems have been installed to date, and customer demand has exceeded available funding for the program.
- Lakeland is currently reviewing alternative approaches for funding the installation of additional systems in 2007:
  - One possible approach is to launch a voluntary green pricing program where customers would pay a small additional amount on their bill to support the solar hot water program.
  - Another approach would be to establish a public benefits fund that adds a small amount to each customer's bill.
  - Lakeland could also pursue new grant funding, but this option is less appealing given the short cycle for most grants (not sustainable long-term).

Target customers and eligibility requirements

- Single family residential only (water usage at hotels and dormitories is too variable depending on time of week or time of year).
- Rental properties and seasonal residents are excluded.
- Households with usage of 70 gallons/day, typically with 3-5 members.
- South-facing roofs in good condition with no current or future obstructions (site inspection conducted before installation).

Program marketing

Lakeland marketed the original program with bill stuffers, but minimal marketing was required due to the limited size of the pilot program and the popularity of the program which spread information very effectively via word-of-mouth. According to Curry, the program is extremely popular and basically sells itself.

Customer motivations

Curry describes the typical program participant as primarily motivated by “green” sensibilities. Most participants are professionals and the program was not originally marketed as an opportunity for saving money. However, as electric rates have risen due to increasing fossil fuel prices, the solar hot water customers have ended up reaping bill savings of $12-15 per month as well under their fixed-price contracts.

Obstacles encountered and addressed

According to Curry, a big challenge is overcoming the risk perception (from the utility’s perspective) of maintaining a system that is installed at a customer’s facility. The program now has a proven 10-year track record and installations have survived hurricanes as well as transfers of ownership. After Hurricane Jean, Curry received calls from customers whose electric power had been out for 10 days, but their solar hot water heaters were still working. Risk is also mitigated by the planned sale of the system of the customer after 10 years (or 15 years if contract extension is granted).

Curry also emphasized that engaging the local contractor/installer community in the program through an open bid process has been essential in order to overcome potential for political opposition. All installation and maintenance work is conducted by contractors, and Lakeland employees are only involved in overall program management (1 staff) and meter reading.

Scalability

Current plans are to install hundreds of additional systems beginning in 2007. Lakeland’s service territory has 95% saturation for electric water heaters. Curry estimates market saturation (taking into account eligibility requirements) in Lakeland’s service territory would be 10,000-20,000 installed systems.

4.2. Private sector ownership model

Though examples of the utility-owned third party ownership model are quite rare, some companies in the private sector are employing a similar third party ownership model. As described in the case study in this section, SunEdison finances, installs, and maintains solar PV systems on the roofs of large commercial customers such as Whole Foods and Staples, and the customer buys the electricity produced by the system under a fixed-rate contract as a hedge against rising energy costs (McCarthy 2005). A company in Toronto, Mondial Energy, employs a similar model for selling the energy produced by solar hot water heating systems to apartment buildings and commercial establishments with high demand for hot water (Cliburn 2006). Across the country, energy service companies (ESCOs) like Ameresco, Noresco, Conservation Services Group, and Chevron Energy Solutions are entering the renewable energy business using a fee-for-services model (Stern 2005). Initially, many ESCO-driven projects have been at governmental or institutional facilities, like the pioneering Noresco project that installed a 750 kW wind turbine, a 75 kW PV covered parking structure, and HVAC system upgrades at the federal prison in Victorville, California (Fenlon & Debenham 2004).

In Wisconsin, non-utilities cannot provide electric service, though they can provide thermal energy service (e.g., hot water). Solar Mining Company experimented with the third party ownership model for providing solar thermal to Madison-area schools, but the program has since been discontinued (Wichert 2006). One way around Wisconsin's restriction against providing renewable electricity services as a non-utility is for the arrangement to be set up as an equipment lease rather than an energy sales agreement, where the renewable energy generating equipment would be leased at or below the customer's normal cost of electric service. In a recent report evaluating business models that can be used to overcome barriers to solar electric sales and installation, Mark Daugherty (May 2006) examined the potential for third party ownership structures to provide a mechanism for nonprofits to access federal tax incentives through the lease of a system owned by a tax-motivated investor. The model Daugherty examined involved establishing an LLC to own the PV system, with equity provided by a tax-motivated investor that would receive the benefits of tax credits and depreciation. The nonprofit would either lease the system or pay the LLC for the energy produced. Though Daugherty found such an arrangement could reduce the nonprofit's costs for renewable energy by more than 10 percent, his analysis notes that the tax code prohibits equipment leased by a nonprofit from qualifying for federal tax incentives. The lease arrangement would not be problematic for a for-profit entity, but Daugherty concludes that as long as the company has sufficient access to capital and is able to access the benefits of tax incentives, it would receive greater financial returns by purchasing the system directly. Results from a recent in-depth Focus on Energy analysis of third party ownership models are discussed in the section below entitled, *Cash Flow Analysis: Third Party Ownership Models for Commercial Solar Systems*.

- Advantages of the third party ownership model include:
  - Overcomes customer barriers by reducing the "hassle factor" and providing renewable energy service without requiring substantial up-front investment, technical expertise, or ongoing maintenance on the part of the customer.
  - Enables bulk purchases of renewable equipment which is likely to lower the per-system cost.
- Disadvantages of the third party ownership model include:
  - Capital-intensive for the system owner; requires adequate financial resources and long-term interest in providing the service.
  - For for-profit end-users, uncertain financial advantage when compared with direct system ownership, particularly when the customer is able to recoup the benefit of federal tax incentives.
  - For non-profit end-users, an equipment lease structure would preclude the system owner from receiving federal tax incentives, and energy sales agreement structure would be prohibited in Wisconsin.

Case study: SunEdison solar electric services

Business Model Type

Third party ownership of solar PV.

Location

SunEdison's target markets are in states with high solar incentives (New Jersey, California) as well as markets with high electricity prices and good solar resources.

Case study references

- Claire Broido, SunEdison (March 18, 2004). Presentation at the *World Resources Institute's Sustainable Enterprises Summit, 2004*. "Solar Energy Services: Delivering Cost-Effective Solar Power." Available at: http://summit.wri.org/2004_content.cfm?cid=2381.

Business model description

Customer purchases solar electric service at fixed price under long-term contract (10 or 20 years). SunEdison develops the project, coordinating system design, construction, and financing with a third party investor (e.g,,Goldman Sachs), and also provides ongoing system maintenance services. The PV manufacturer (e.g., BP Solar, Sharp) installs the system and provides warranties for equipment and performance. The tax-motivated investor provides the capital and owns the system, earning a return on its investment through electricity sales revenues and any applicable federal/state incentives (tax credits, etc.).

Project siting and metering

Customer sited, not interconnected.

Factors ensuring business model success

- SunEdison has developed standardized system design to reduce up-front costs, obtained bulk purchasing discounts from nation's largest PV manufacturers, and developed a structured financing approach to minimize risk and provide reasonable return to third party investors. By targeting large commercial chains like Staples and Whole Foods, they maximize the potential for serving multiple sites.
- Customer obtains renewable energy with no capital investment and minimal hassle at a price less than or equal to its standard utility rate, under a long-term fixed price agreement that provides a hedge against volatile energy prices.
- Third party investor obtains low-risk return on investment in renewable energy.

Target market

Customers with a commercial rate structure and demand less than 1,000 kW.

Eligibility criteria

- Building roof with minimum 10 years of additional life.
- 10,000 sq. foot of unshaded roof per 100 kW.

Business model goal

- To provide a win-win solution that links renewable energy investors with customers interested in renewable energy but deterred by up-front costs or hassle factor of purchasing their own system.

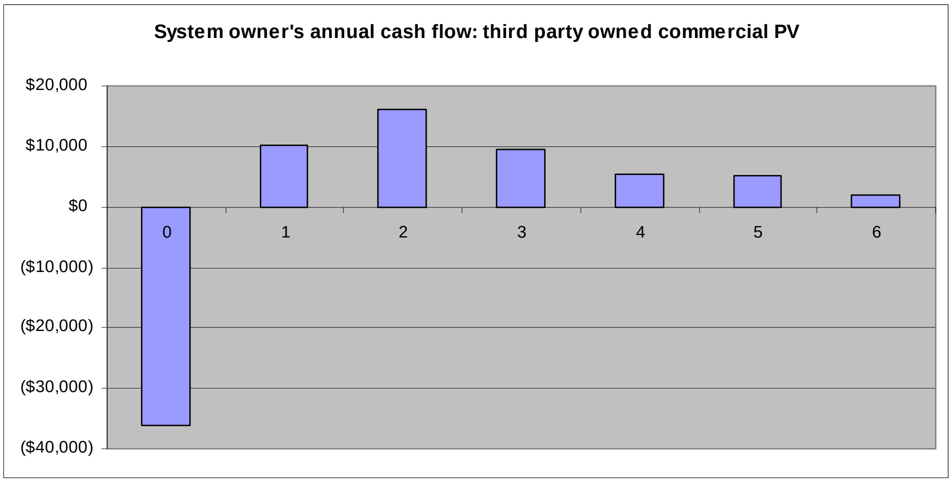
Cash flow analysis: third party ownership models for commercial solar systems

A recent financial analysis for Focus on Energy conducted by John Young of Accipiter Properties (2006) provides an in-depth exploration of the financial viability of third party ownership models for commercial-scale solar electric and solar thermal systems. The model addressed in Young's analysis envisions an ownership structure similar to the one employed by SunEdison, namely a partnership between a customer, a tax-motivated investor (typically a C-corporation), a lending institution, and a project developer. The developer and the C-corporation establish an LLC to own the equipment for the first six years of the project, financing the equipment purchase and installation with an equity contribution from the C-corporation and a commercial loan. The C-corporation receives the benefit of all tax incentives, and the customer makes an annual lease payment to the LLC, agreeing in advance to purchase the equipment and refinance (if necessary) at the end of the first six years. [‡‡‡]

Using a somewhat simplified version of Young's financial model, we developed a cash flow analysis of a 20 kW commercial solar PV installation with an annual output of 24,000 kWh (capacity factor of 14 percent) and an installed cost of $150,000. The third party owns the system for the first 6 years, the period of accelerated MACRS depreciation, and receives the federal business energy tax credit of $45,000 in addition to the Focus on Energy incentive of $35,000. From Years 1 through 6 the customer makes an annual lease payment of $11,178 (9.72 percent of the installed project cost). The third party owner incurs up-front marketing and administrative costs of $12,000 and an additional annual administrative expense of $1,525 during its ownership period. Base O&M costs are $525 per year increasing at 2 percent annually. The project is financed with 60 percent equity and 40 percent debt, with a 10-year bank loan at 9.25 percent interest (Prime +1). Beginning in Year 7, the customer takes over the annual principal and interest payments. The customer's avoided electricity expense is based on We Energies TOU rate of $0.20/kWh on-peak and $0.038/kWh off-peak. A combined state and federal tax rate of 40 percent for both parties is assumed. A discount rate of 10 percent is used for NPV calculations.

The figures below present the post-tax annual and cumulative cash flows for the third party owner and the commercial end-user.

Figure 4-1. Annual cash flow for third party system owner



‡‡‡ Young's analysis is available at http://www.focusonenergy.com/data/common/dmsFiles/W_RW_RPTE_AltEnr3rdPrtyFinDevJYoun%20.pdf.

Figure 4-2. Cumulative cash flow for third party system owner

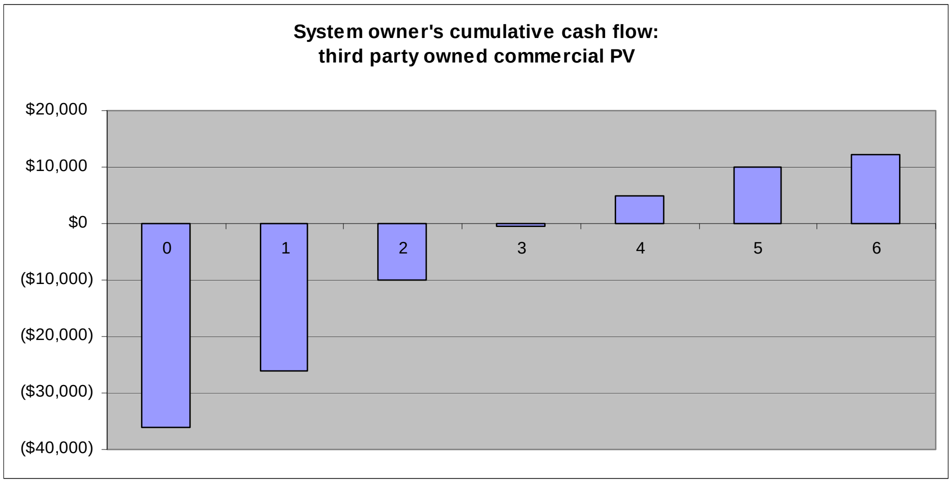


Figure 4-3. Annual cash flow for customer, third party ownership of commercial PV

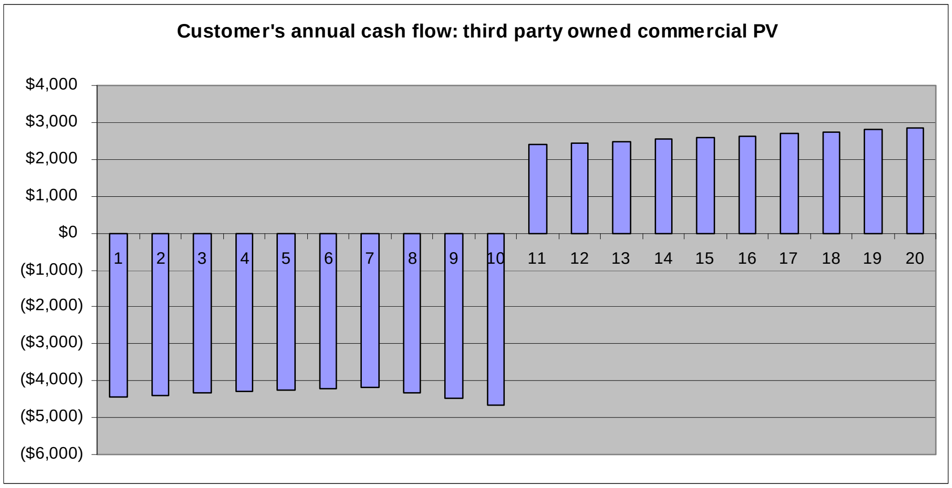
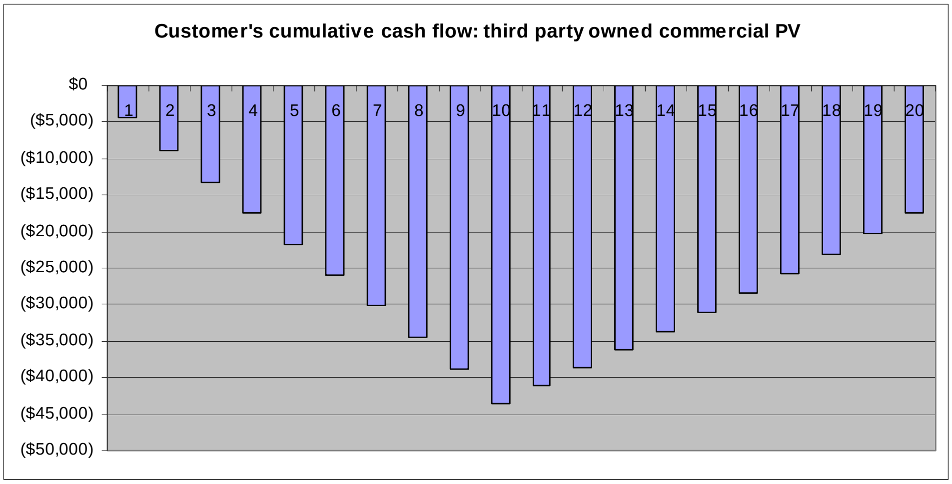


Figure 4-4. Cumulative cash flow for customer, third party ownership of commercial PV



The model provides the third party owner with a 12 percent IRR over the 7-year period, with the NPV of the post-tax cash flow at $1,300. For the commercial customer, the project does not achieve payback within the 20-year timeframe, and the NPV of the 11- and 21-year cash flows is negative.

According to Young's analysis, the third party ownership model is most favorable for customers that are committed to supporting renewable energy but are unable to recoup the benefit of federal business tax incentives (e.g., nonprofits). For such customers, the third party ownership model would theoretically achieve a 10 to 20 percent cost savings over outright system purchase, with the important caveat (as previously discussed) that the tax code prohibits equipment leased by a nonprofit from qualifying for federal tax incentives. The third party ownership model does not offer a financial advantage to for-profit customers that can utilize the full benefit of federal tax incentives. The Figures below show the post-tax annual and cumulative cash flows for the same project under direct ownership by a commercial end user with sufficient tax liability to recoup federal tax incentives, who also receives We Energies solar buyback rate of $0.225/kWh for the first ten years.

Figure 4-5. Cumulative cash flow for direct ownership of commercial PV

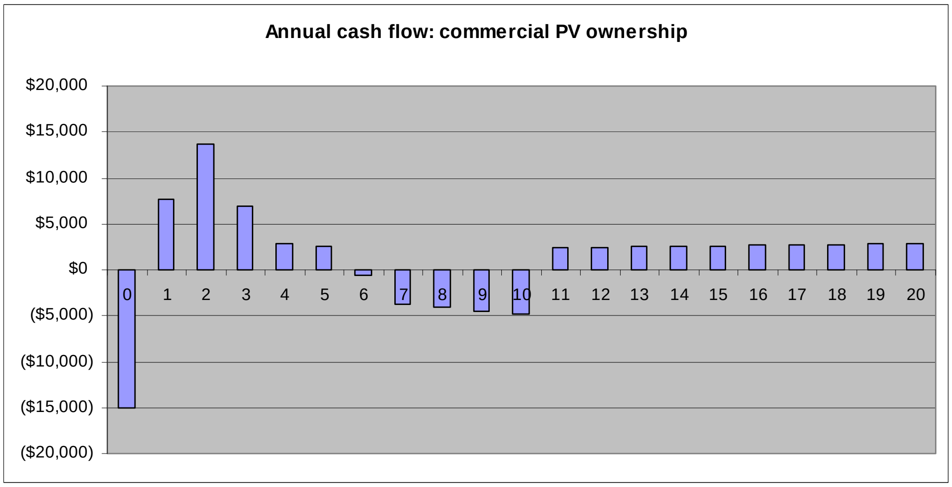
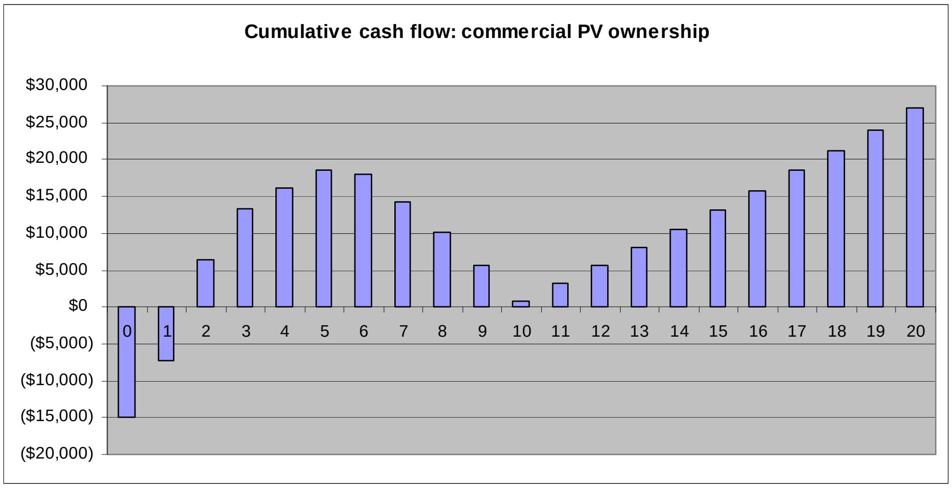


Figure 4-6. Cumulative cash flow for direct ownership of commercial PV



4.3. Cooperative ownership model

Citizens Energy Cooperative (CEC) of Wisconsin is a supplier cooperative located in Waupaca that was established two years ago. In addition to providing cooperative members with site assessments and home installation services for residential solar thermal and PV systems, the cooperative also purchases and installs solar hot water systems on community buildings under a third party fee-for-service arrangement (Nusz 2006). Such installations are funded by cooperative members who want to support renewable energy development in Wisconsin by entering into energy production agreements. Members sign up to fund a certain number of renewable therms per year at a fixed price (currently $1.55/therm), and CEC installs solar hot water systems on community-oriented facilities like the Green County YMCA at no cost to the facility owner. CEC provides its hot water service at a 5 percent reduction from the price the facility would otherwise for natural gas. After 20 years, CEC will turn over ownership of the system to the facility at no cost.

Though the cooperative is not yet turning a profit off of the sale of energy through the third party arrangement, Executive Director Chamomile Nusz expects that after five or six years members will begin to receive dividends on the renewable therms they have funded. The number of installed systems is dependent on the number of cooperative members and their individual commitments to fund the procurement of renewable therms. CEC markets its services to new members primarily through grassroots outreach and educational events.

The cooperative currently has 260 members and produces 26,000 renewable therms per year through six installed solar thermal systems. Three of these systems are owned by CEC and three are owned by Solar Mining Company.

- Advantages of the cooperative ownership model include:
  - Creates mechanism for environmentally-motivated consumers to support renewable energy development at relatively low cost.

  - Overcomes customer barriers by reducing the “hassle factor” and providing renewable energy service without requiring substantial up-front investment, technical expertise, or ongoing maintenance on the part of the customer.
- Disadvantages of the cooperative ownership model include:
  - Capital-intensive for the cooperative; assuming relatively small individual contributions on the part of cooperative members means that membership must be broad to provide sufficient capital for the installation of new systems.
  - Achieving wide membership solely through grassroots marketing efforts is difficult.

5. Project aggregation model

As described in Section 2.2, aggregation of renewable energy generating projects under a single PPA and financing package is one mechanism for overcoming barriers to obtaining third party financing for small-scale renewable energy projects, potentially allowing the projects to achieve sufficient scale to attract institutional-scale investment.

One developer who installs behind-the-meter utility-scale wind turbines at commercial and industrial facilities discussed the difficulty of obtaining third party financing for customers with anything less than a AAA credit rating, though other developers believe such concerns are overwrought (Michelman 2006). Financing institutions may consider such behind-the-meter projects too risky as they depend entirely on the financial health of a single facility. Aggregation of such projects could provide a mechanism for diversifying risk and simplifying the turbine procurement and power sales agreement processes, and allow the projects to achieve sufficient scale to attract institutional investment. In some ways, this model is similar to the third party ownership model used by SunEdison, which aggregates projects by working with large chains like Staples and Whole Foods under a single agreement involving multiple retail locations (see Section 4.2), though the customer retains ownership of the renewable assets under the project aggregation model.

Though renewable energy developers have expressed interest in project aggregation, the model has not been attempted in the marketplace due to the complexities and challenges of working with multiple companies on different project timelines. Structuring the model as a utility program would be one approach to implementing the model. The program could be structured in a similar way to RFP programs for large scale C&I energy efficiency projects, where the utility submits an RFP to a targeted set of customers, and the most promising bids are accepted into the project portfolio. Once the pre-development work is completed (site assessment, wind resource monitoring, interconnection studies, permitting, etc.) and a standard power purchase agreement executed with program participants, the entire portfolio could be submitted for financing by potential investors.

- Advantages of the project aggregation model include:
  - Though it is not necessary that such a model by implemented by a utility, utilities may be uniquely suited to implement the aggregation model due to their access to information about customer energy usage and established account management relationships with large energy users.
  - Program would likely be well received by potential customers. One developer described how the perceived “sexiness” of renewable energy projects means that some customers have a tolerance for longer paybacks than they would for other capital projects. In particular, institutional and government customers may be willing to consider longer paybacks than commercial or industrial customers.
  - Enables bulk purchases of renewable equipment which is likely to lower the per-system cost.
  - Projects would provide a built-in price hedge for the on-site load.
- Disadvantages of the project aggregation model include:
  - Program model involves a long project timeline and would be labor-intensive to administer.
  - Program would impact utility revenues, unless structured as a third party model where the utility retains ownership of the renewable assets.
  - Untried model in the marketplace.

6. Renewables-as-appliance models

A recent analysis by the Topline Strategy Group asserts that in order for solar PV to achieve mass market adoption, the following conditions must be met: (1) the size of the initial investment must be reduced; (2) there must a reliable and trusted sales channel for small systems that minimizes the hassles associated with system purchases (financing, rebate paperwork, permitting, interconnection, etc.); and (3) consumer confusion about the technology must be reduced through the use of standardized rating systems that facilitate comparison shopping (Klein and Erlichman 2006). The solutions proposed in the Topline analysis center around simplifying the sales, financing, and installation process for PV, in essence making the PV purchasing and installation experience closer to that of traditional household appliances. Though the Topline report focuses on PV, its conclusions may also be applicable to other residential applications such as solar thermal and residential-scale wind turbines. In this section we focus on two mechanisms that could be employed by business models seeking to employ a “renewables-as-appliance” approach: (1) selling PV through high volume retail sales channels and (2) manufacturing renewable energy systems that offer simplified configuration approximating “plug and play” applications.

6.1. Retailer sales model

The best example of selling renewable energy technologies through a standard retail sales channel is the partnership between BP Solar and The Home Depot, which has been offering the BP Solar Home Solution® to consumers in California since 2004, and has expanded to other states with high solar incentives such as New York and New Jersey. Embodying some of the recommendations proposed in the Topline analysis, this business model leverages the reputation of a trusted home improvement retailer, streamlining the sales and installation process for purchasers of small systems. Reaping the benefits of a “one-stop shopping” approach, consumers receive a free in-home consultation to determine the appropriate system size and configuration, and can take advantage of system financing options such as The Home Depot Consumer Credit Card or The Home Depot Home Improvement Loan. Installation is conducted by an approved contractor, and inspected by a Solar Home Solution project manager ensure quality control. To reduce customer concerns about the risk of maintaining unfamiliar technology, BP Solar offers a 7 year full service warranty and 25 year limited warranty. In addition to handling utility approvals and permitting, the assigned project manager also handles the relevant paperwork to apply for state or utility rebates, and the rebate amount is deducted from the purchase price.

As noted above, the Topline report concludes that more effective sales channels for small PV systems need to be developed. The analysis notes that one of the challenges of the traditional installer-driven business model is that there are high fixed costs associated with generating leads, qualifying prospective customers, designing the installation, handling permitting and inspections, and filling out rebate paperwork (Klein and Erlichman 2006). These costs have driven installers—typically small businesses with limited resources—to focus on selling larger systems. However, a 4 kW PV system costs around $25,000. Even after rebates, the magnitude of this investment entails a high risk for the consumer and limits the mass market appeal of solar technologies. The Topline analysis suggests that 1 kW starter systems costing around $5,000 after rebates have much higher potential for mass market viability by reducing the magnitude of the investment and associated risks. The report concludes that home improvement retailers could provide an effective sales channel for these small starter systems, leveraging a trusted brand identity and marketing power that small installers are unlikely to be able to offer. With the retailer taking care of the marketing, sales, and financing, the fixed costs of customer acquisition are lower for installers, and standardized equipment configurations requiring minimally invasive installation lower the design and installation costs.

Advantages of the retailer sales model include:

- Minimizes the burden on the consumer by offering a single solution that encompasses sales, financing, installation, and paperwork.
- Decreases consumer concerns about risk by leveraging a trusted retailer brand.
- Leverages retailer marketing power, reducing consumer search costs and potentially providing an effective sales channel for small systems that face a lower investment hurdle.
- Reduces customer acquisition costs for the installer by leveraging retailer and manufacturer marketing.

Disadvantages of the retailer sales model include:

- The likelihood of engaging retailer support for the model is dependent on the magnitude of solar incentives, as well as expectations regarding the long-term stability of incentive offerings.
- Requires the development of partnerships between parties that may not have established business relationships, namely manufacturers, retailers, installers, and financial institutions.
- Retailers may be reluctant to take on the risks associated with selling renewable energy technology, or investing in the store configuration and sales associate training that would be required to make the model successful.

The success of the model requires the retailer to take a leadership role in developing the business model, most likely in partnership with system manufacturers and installers. John Bahr, a RENEW Wisconsin board member, contacted a few retailers in the Milwaukee area to gauge their potential interest in setting up in-store displays about solar energy (Bahr 2006). Though Bahr contacted a limited number of locally-owned stores and his efforts did not constitute a formal survey, he did not find a strong degree of retailer interest, with several storeowners mentioning space constraints as limiting the opportunity for installing such displays.

6.2. Standardized configuration model

Simplified installation is also fundamental to the renewables-as-appliance business model. Standardized equipment configurations minimize or eliminate tailored design requirements, offering all necessary components in a single package and simplifying the installation process. Standardized configurations may also facilitate another key component of the renewables-as-appliance approach, namely an installed cost that is within the range of what customers would be willing to pay for a high-end appliance (under $10,000).

The Topline analysis notes that offering unlimited design flexibility—as is common in the solar industry—increases sales, design, installation, and equipment costs (Klein and Erlichman 2006). Such flexibility can be a deterrent from the customer's perspective, as customers must educate themselves regarding various alternatives and may be dissuaded by the complexity of determining the appropriate configuration. For PV, the Topline analysis envisions how a plug-and-play solar product would facilitate mass market adoption. They propose development of a free-standing adjustable tilted frame supporting five standard PV modules, with a locking cabinet underneath that encloses the inverter and ballast, and a long cord that plugs into a 110-volt or 220-volt outlet. Topline envisions this 1 kW solar system as one that could readily be sold in a high-volume retail sales channel at a price that is comparable to other high-end appliances (Klein and Erlichman, 2006).

As solar thermal technologies typically require more invasive installation processes than PV in order to connect with domestic hot water systems, the standardized configuration model may be less applicable to solar thermal. However, Don Wichert of Focus on Energy notes that the success of solar thermal applications in Hawaii is in part due to the use of standardized component packages, and Citizens Energy Cooperative of Wisconsin has also pursued the use of standardized configurations for its solar thermal installations.

For wind, Southwest Wind Power sought to develop a residential-scale wind turbine that is relatively low-cost, low-hassle to install, and operates effectively at the lower wind speeds found in a residential setting. Developed in partnership with NREL, the Skystream 3.7 was launched in 2007 after several years of beta-testing. The Skystream's 1.8 kW turbine activates at wind speeds of 8 mph and hit maximum output at 20 mph, where most conventional turbines require wind speeds of 30 mph. The turbine is designed to be grid-interconnected so it can take advantage of the full retail rate for power under a net metering arrangement, the turbine will do battery charging, and all components required to run the system (converter, electronics, and controls) are contained within the turbine body. The turbine also comes with a remote monitor that provides data on power generation and wind speed. Skystream's CEO estimates the turbine can produce between 35 to 70 percent of a home's electricity needs, and the installed cost is around $12,000 before rebates (Rich 2007). According to John Dunlop of AWEA (2006), Southwest Wind Power plans a production capacity of 1,000 turbines a month, which is higher than the industry norm.

Advantages of the standardized configuration model include:

- Simplifies the search process and decreases complexity for the customer.
- Decreases design and installation costs.
- Facilitates mass production.

Disadvantages of the standardized configuration model include:

- Installation of standardized configurations may not be suitable in all locations.
- Ensuring high quality in conjunction with low cost has historically been difficult for manufacturers to achieve (Dunlop 2006).

Though the examples noted in this section indicate that standardized equipment configurations are beginning to gain ground in the marketplace, there are still plenty of additional opportunities for manufacturers and installers to promote the model.

7. New construction model

Bundling renewable energy technologies such as PV and solar thermal into residential new construction offers several business model advantages. For the developer, offering potential home buyers a “solar option” can represent an added selling point, which may be particularly valuable in highly competitive construction markets. From the homeowner’s perspective, such options eliminate the time, technical complexity, and informational requirements associated with implementing a solar retrofit (Barbose et. al. 2006). New construction can also be designed to be “solar-ready,” to facilitate the addition of post-construction solar retrofits. For PV, solar-ready residential construction includes ensuring sufficient roof area, proper roof pitch/orientation, and pre-installed wire chase and circuitry. For solar thermal, solar-ready construction includes ensuring an appropriate roof structure to support the collectors, a place for the water storage tank that comports with plumbing infrastructure, and pre-installed pipe chase.

A number of builders in California and other states offer pre-installed solar systems in new residential developments. Though solar PV systems have been more common to date, the model is also applicable to pre-installed solar thermal systems. Clarum Homes, based in Palo Alto, California, has offered installed solar electric systems and other energy-efficient features as standard offerings under its Enviro-Homes™ brand since 1999, with PV systems ranging in size from 1.2 to 3.2 kW. At Ladera Ranch, a planned community in Southern California, 465 homes with pre-installed PV were constructed by 10 builders following a mandate by the master developer. And in August 2006 the San Francisco Public Utilities Commission announced a plan to create the city’s first neighborhood powered entirely by renewable energy at the former Hunters Point Naval Shipyard. Lennar Corporation is the developer for this project that will consist of more than 1,600 residential units and 300,000 square feet of commercial and retail space located in an area of the city with environmental justice concerns (California Energy Commission 2004).

State and utility incentives have provided critical support for the new construction model. The Sacramento Municipal Utility District (SMUD) has offered an incentive of $2.80/watt, leading a number of Sacramento-area developers to offer pre-installed PV in their residential developments, including Premier Homes and Treasure Homes. Roseville Electric, also in the Sacramento area and offering an incentive of $4/watt, has partnered with Lennar Corporation to build 450 solar-powered homes installed with the PowerLight SunTile, a form of building-integrated PV. Policies enacted at the state or local level, such as streamlined permitting processes or mandated solar new construction targets, have also played a role in advancing the new construction model.

A recent analysis of PV in residential new construction by LBNL cites the following advantages of the model (Barbose et. al. 2006):

- Initial costs may be reduced through standardization of design and installation. Bulk equipment purchases may also lower costs for modules and inverters, particularly at the scale offered by large residential developments.[§§§]

[§§§] Another LBNL analysis indicated that on average, the cost of pre-installed PV systems in large developments was between $1.20/W and $1.70/W lower than comparable retrofit systems (Wiser et. al. 2006). However, no cost savings were found for pre-installed PV systems in single family homes or small developments.

- Transaction costs associated with system financing are reduced by incorporating PV system financing into the home mortgage, eliminating the need for a separate financing transaction.
- Search costs and informational barriers are also reduced, particularly when the solar system is offered as a standard offering rather than a buyer-selected option for the new home purchase.
- System performance can be optimized through design considerations that ensure proper building orientation and minimize shading.
- Aesthetic objections to rack-mounted PV may be overcome through building-integrated PV, which is generally better-suited to new construction applications than retrofit applications.
- In addition to market differentiation, builders may also reap the benefits of favorable media coverage and greater political support for new developments.

At the same time, the new construction model faces some unique challenges:

- The success of the model is dependent on effective coordination between a diverse set of parties. According to the California Energy Commission (2004), the success of the new construction business model for PV requires developing innovative and effective partnerships between builders, PV manufacturers, installers, financers and lenders, utilities, and local government. The LBNL study notes that in particular, large production homebuilders may require more comprehensive support services from solar installers (such as incentive processing, interconnection and permitting requirements, etc.), or may insist on using their own electrical or roofing sub-contractors rather than PV installers (Barbose et. al. 2006).
- The model may face opposition or lack of interest from homebuilders due to technology risk aversion, as well as concerns about how solar installations will affect building costs, project schedule (which may be impacted by permitting delays as well as solar equipment availability), home prices, and profits (Barbose et. al. 2006).
- When PV is available as an option for the buyer rather than a standard feature, a higher level of sales expertise and training is required to effectively “sell” the system to prospective buyers. Barbose et. al. (2006) note that the new construction model is markedly less successful in promoting PV when system installation is an option that buyers must choose. Transaction costs may also be higher as installation scheduling and permitting processes are more complex.

Though the building community may perceive that buyers may be averse to solar homes due to concerns about cost, system maintenance, and aesthetics, there is also some evidence that builders may be able to charge a premium for solar homes as they would for other high-value home features. In a Roper survey commissioned by Sharp Electronics Corporation, two thirds of respondents indicated they would be willing to pay a premium for a solar home provided they were assured a higher resale value, with half of respondents indicating they would pay a premium of up to 10 percent (Judd 2006). Barbose et. al. (2006) note that some preliminary studies have indicated PV and other energy-efficient features have a positive effect on home resale value, though they point out a need for additional study of this issue.

Cash flow analysis: PV in residential new construction

To illustrate the new construction model from the customer’s perspective, we developed a cash flow model for a 2 kW residential PV system financed through a home mortgage. The installed system cost is $15,000 and annual production is 2,400 kWh (a 14 percent capacity factor). The customer receives a Focus on Energy grant of $3,750 and a federal tax credit of $2,000. O&M expenses consist of $600 in Year 10 for inverter replacement. The project is financed through a 15-year fixed rate mortgage at 6.13 percent interest. The customer receives We Energies solar buyback rate of $0.225/kWh for the first 10 years, then an avoided electricity expense beginning in Year 11 at $0.122/kWh increasing 2 percent annually. A combined state and federal tax rate of 40 percent is assumed. A discount rate of 10 percent is used for NPV calculations.

Under this model, the customer's IRR for Years 0 through 10 is 12 percent, and the customer's IRR for Years 0 through 20 is 16 percent. The NPV of the 11-year cash flow is -$350 and the NPV of the 21-year cash flow is -$1,600.

The figures below present the annual and cumulative post-tax cash flows:

Figure 7-1. Annual cash flow for PV in residential new construction

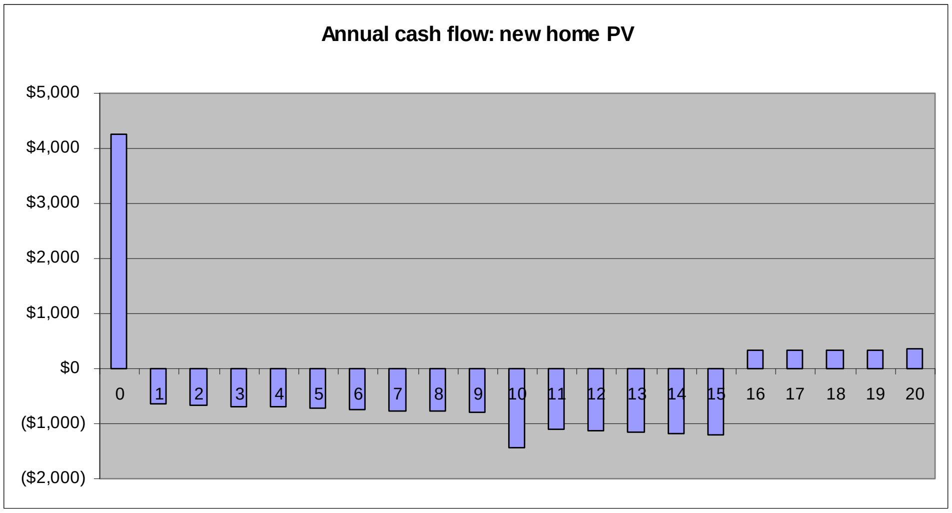
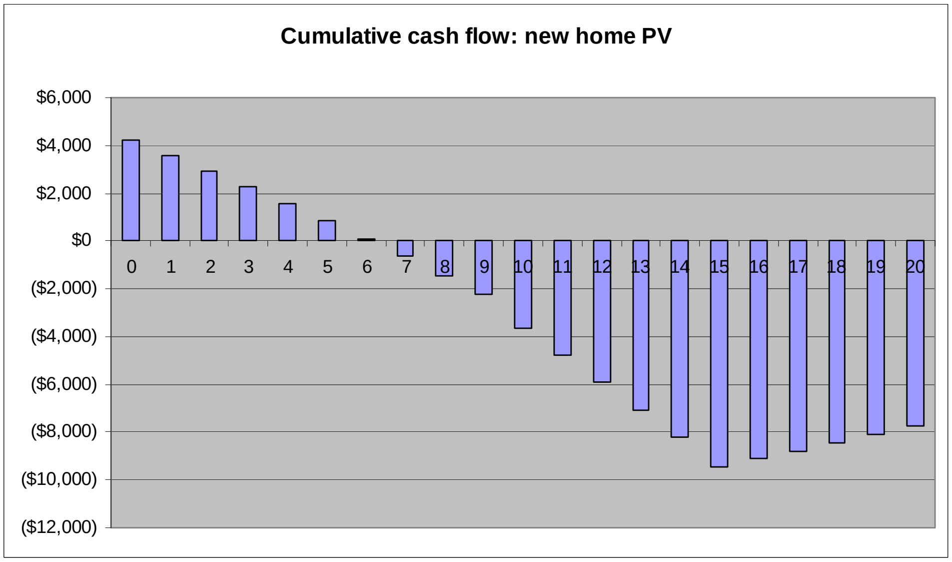


Figure 7-2. Cumulative cash flow for PV in residential new construction



This page deliberately left blank.

8. Environmental credit market models

A number of factors—including regulatory frameworks such as Renewable Portfolio Standard (RPS) requirements as well as concerns about climate change and energy security, etc.—are driving the emergence of environmental credit markets which seek to establish a commoditized value for the non-energy attributes of renewable power generation. Such non-energy attributes may be environmental (i.e., the value of reduced pollutant or carbon emissions as compared with fossil fuel-generated electricity) or resource-based (i.e., the value of renewably-produced or locally-produced electricity) (Holt 2005). Several of these markets have the potential (either currently or in future) to provide revenue streams for customer-owned renewable energy projects:

- **Renewable Energy Credit (REC) markets**: RECs represent a quantification of the non-energy attributes of power generated using renewable resources, "unbundled" from the value of the electricity itself. REC markets exist both for regulatory compliance purposes and for voluntary consumption by end users of energy (both companies and individuals). Compliance markets—representing the largest REC trading volumes—are generally wholesale markets in which electric generators participate in order to comply with state RPS requirements or other regulatory frameworks (Holt 2005). In voluntary markets, RECs may be sold to end users as stand-alone products (i.e., without associated electricity sales) or bundled with electricity as a green power product (Holt 2005).
- **Carbon offset markets**: There is a growing voluntary market (i.e., not currently regulated) for carbon offsets, in which organizations can offset some of the carbon emissions produced by their energy consumption through the purchase of carbon credits. Carbon offsets are created in a variety of ways including sequestration (capturing carbon) or emissions reduction (substituting renewable for fossil generation or reducing fossil generation through energy efficiency). Offset projects include methane destruction, forestry practices, renewable energy, Clean Development Mechanism projects (creditable projects in developing countries under the Kyoto Protocol), agricultural practices and energy efficiency. This market is currently strictly voluntary, though regional initiatives such as the Northeast Regional Greenhouse Gas Initiative and California's 2006 greenhouse gas legislation are likely to establish regulatory frameworks for carbon offset markets. In the voluntary market, participants can arrange bilateral trades or participate in an organized trading system like the Chicago Climate Exchange (CCX).

> **Participating in Multiple Markets**
>
> To avoid double-counting problems and maintain the integrity and credibility of these emerging markets, advocates recommend against disaggregation of renewable energy attributes for participation in multiple markets—for example, seeking to disaggregate RECs from offsets of carbon emissions. However, in some limited cases a renewable energy project could receive revenue streams from participation in multiple markets. For example, anaerobic digesters may receive carbon offset credits for decreased methane emissions resulting from implementation of an improved manure management strategy, and RECs for the generation of electricity from biogas.

- **Emissions allowance markets**: Emissions allowance markets exist in places where cap-and-trade systems have been established to achieve compliance with National Ambient Air Quality Standards (NAAQS) under the Clean Air Act (for example, statewide caps on NOx emissions as part of the State Implementation Plan (SIP) strategy to address non-attainment issues). Though some programs preclude or discourage renewable energy projects from participating (like the nationwide SO_2 cap-and-trade program), some programs enable renewable generating units to apply for allowances from the main allowance pool, or even establish a defined sub-set of allowances (i.e., a "set-aside") which may only be allocated to renewable projects. These allowances can be attached to a REC, to make it a premium renewable energy product or a REC-plus, or sold separately in allowance markets.

Given the volatility of these emerging markets, information on market prices is quickly outdated. However, Holt's NREL analysis published in January 2005 compares the energy value of the various credit markets in 2004:

- Compliance REC prices are typically in the range of 0.05¢/kWh to 15¢/kWh.[****]
- Retail prices in voluntary REC markets are mostly between 1¢/kWh and 2.5¢/kWh, with a high range of 4¢/kWh to 5¢/kWh, and a price of 20¢/kWh for one solar-only REC product offered by Mainstay Energy.[††††]
- Wholesale prices for solar RECs in voluntary REC markets range from 3¢/kWh to 20¢/kWh, and wholesale prices for wind/biomass/hydro RECs range from 0.2¢/kWh to 0.6¢/kWh.[‡‡‡‡]
- SOx allowances offer 42¢/kWh (only available in limited exceptions), NOx allowances offer 0.23¢/kWh (only available where states have established eligibility for renewables), and carbon offset markets offer 0.087¢/kWh.[§§§§]

Though the sale of RECs, carbon offsets, or emissions allowances may comprise a cash-flow element in customer-owned renewable energy projects, such sale does not necessarily warrant the distinction of being a "new business model." However, in the interest of collecting a broad range of innovative financing mechanisms for customer-owned renewable projects, and as the future viability of REC, carbon offset, and emissions allowance markets is likely to increase, we include a discussion of ways in which these markets may be accessed to provide additional cash flow for renewable energy projects, and to fund the installation of new projects.

8.1. REC market models

RECs offer producers of renewable energy a fairly simple way to capture an environmental premium to supplement the revenues they earn from kWh they produce. The price of RECs varies by resource type used to generate power, with cleaner resources such as solar power and wind energy usually being priced slightly higher than resources that produce some emissions, such as biomass or landfill gas. REC prices also vary by location. If a company has a strong desire to provide local air quality benefits in the region in which it operates, it may be possible to purchase locally-sourced RECs. These local renewable generation sources will have a greater impact on local emissions than RECs purchased from renewable generators in distant locations.

[****] Reported prices for compliance RECs by state are based on publicly available REC trading prices (CT, ME, MD, MA, NJ, NY, PA, RI, and TX) as well as the researchers' professional judgment for states without publicly available REC trading prices (AZ, CO, NV, NM, and WI). The highest compliance REC prices are found in states with a tiered RPS, such as 15¢/kWh for New Jersey's solar RECs.

[††††] Retail REC price ranges are based on the prices published by REC retailers such as 3 Phases Energy, NativeEnergy, Sterling Planet, etc.

[‡‡‡‡] Reported wholesale prices are based on the following regional trading pools: California, WECC, Central, PJM, New York, NEPOOL, SPP, and Southeast.

[§§§§] Emissions market prices provided by credit broker Evolution Markets.

The REC market is growingly quickly, and by all accounts, will grow exponentially in the coming years. According to July 2006 data on REC retail products compiled by NREL,[*****] there are more than a dozen REC or carbon offset retailers operating at the national or regional level, including companies like Sterling Planet, 3 Phases Energy Services, NativeEnergy, Carbonfund.org, and TerraPass. Retail prices range from 0.5¢/kWh to 7.5¢/kWh, and $5.50-$12/ton of avoided carbon emissions. (As the generator receives a fraction of the retail price, per-kWh payments for RECs are significantly lower than the premium paid by We Energies under its solar and biogas buyback rates.)

National retailers like Carbonfund.org procure RECs primarily from large-scale commercial renewable energy projects, mainly because these projects have the greatest climate impact and offer the lowest-cost renewable energy, but also because the REC certification process is labor-intensive and thus is most cost-effective for large projects (Carlson 2006).

Advantages of the REC model include:

- The opportunity to market locally-produced renewable energy nationally.
- Promoting investment in local renewable energy projects as investors seek to capture two streams of revenue: sale of power and sale of RECs.
- Allowing consumers who are not able to purchase green power from their utility to access green power markets.

Disadvantages of the REC model include:

- Utility-specific buy-back rates for renewable energy may exceed the sum available to generators through separate sale of electricity and RECs, therefore making this model financially unviable.
- Volatility of future REC prices may cause planned renewable projects to not meet revenue goals.
- Local regulatory landscape may not allow unbundling of RECs from electricity sales, or utility-specific requirements such as interconnection or net metering agreements may restrict customer ownership of RECs.

A small-scale renewable energy generator may be unable to own or sell RECs under existing state regulations or conditions of net metering, PPA, or incentive agreements that assign REC ownership to another party. A number of other factors constrain the viability of REC markets to provide revenue streams for small-scale projects, including unclear or undefined REC ownership conditions as well as the marketing challenges and high transaction costs associated with selling small volumes of RECs in a largely illiquid market. In We Energies' service territory, renewable energy buyback rates incorporate the environmental attributes of the energy produced and the customer has no ability to disaggregate and sell those attributes separately.

There are a number of mechanisms for addressing these challenges, including:

***** U.S. Department of Energy, Energy Efficiency and Renewable Energy (updated July 30, 2006). *Renewable Energy Certificates, Retail Certificate Products*. Available at: http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

- Legislative or contractual clarity about the ownership of RECs for all potential renewable energy projects, including three distinct areas where REC ownership issues have arisen (Holt et al, 2006):
  - Qualifying Facilities (QFs) that sell their generation under the Public Utility Regulatory Policies Act (PURPA) of 1978.
  - Customer-owned generation that benefits from state net metering rules.
  - Generation facilities that receive financial incentives from state or utility funds.
- Aggregating RECs produced by small-scale of projects. Whether through creation of a local cooperative or non-profit organization, or through linking with a national provider of RECs, it is possible for small-scale renewable energy generators to join together and enter the REC market by sharing marketing and transaction costs.

In the Pacific Northwest, the Northwest Solar Cooperative (NWSC) and Our Wind Cooperative (OWC)—both funded in party by grants from the Bonneville Environmental Foundation (BEF)—aggregate and sell RECs produced by small customer-owned solar electric and wind systems. In the case of NWSC, the sale of RECs (called "green tags" in the region) is geared towards creating a production-based revenue stream for small-scale generators for whom the environmental benefits of renewable energy production are not captured in a utility buy-back rate or other incentive. NWSC lines up sales agreements for a defined number tags with entities like BEF and 3 Phases Energy, and then markets the programs to system owners. The owner of a wind or solar system 10 kW or smaller is required to join the cooperative and sign an agreement to sell green tags generated during a defined time period, provided he/she has retained ownership of the tags under the terms of any applicable net metering and incentive agreements. Under the BEF program (currently fully subscribed), system owners were offered 10¢/kWh, and under the 3 Phases Energy program, system owners are offered 5¢/kWh. Though system owners must have already-installed systems before applying to sell their green tags, NWSC staff assist with the up-front Green-e certification and verification work, to some extent on a volunteer basis (Grove 2006).

OWC was established by a partnership of renewable energy advocacy organizations to explore a number of different funding mechanisms for promoting small-scale rural wind development, including revenues from the sale of green tags. As originally envisioned, the project sought to determine whether a market could be found for higher-priced green tags generated by local rural renewable energy development projects. In addition to providing revenue to the host sites, green tag sales revenues were seen as a potential mechanism for funding installation of additional projects. OWC faced a number of challenges in implementing the model (as described in the following case study), and though the cooperative has met its original goal of ten installed projects, no additional installations are currently planned (Grove 2006).

Case Study: Our Wind Cooperative

Project Name	**Business Model Type**
Our Wind Cooperative	Wind cooperative w/ revenues from REC sales
Location	**Utility**
Washington, Montana	Projects are sited in multiple utility territories including Northwest Energy, Glacier Electric Coop, Klickitat

County PUD, Chelan County PUD

Case study references

- Jennifer Grove, Program Director, Northwest Sustainable Energy for Economic Development (Northwest SEED). (December 7, 2006). Personal communication.
- Heather Rhodes-Weaver and Jennifer Grove (March 30, 2004). *Our Wind Co-Op: Exploring Joint Green Tag Financing and Marketing Models for Energy Independence*. Presentation for AWEA conference session on wind energy for farms, homes and small businesses. Available at: http://www.ourwind.org/windcoop/pdfs/AWEA_Paper.pdf.
- Diane Gasaway, Deborah Ross, Jennifer Grove, Peter Moulton. *Our Wind Cooperative: Energy Independence for the Northwest*. Final report prepared for the USDA's Value-Added Development Grant Program. Available at: http://www.ourwind.org/windcoop/pdfs/Final_USDA_Report.pdf.

Project ownership/management structure

Our Wind Cooperative (OWC) established 10 residential-scale (10kW) wind turbines in rural locations in Washington and Montana. Each host site owns the turbine, and all rights to green tags produced by the turbines are assigned to OWC for a 10-year term. Host sites receive no ongoing revenues from green tag sales; rather, OWC uses those revenues to pay down a no-interest loan from the Bonneville Environmental Foundation (BEF), which offered an up-front payment of $60,000 ($6,000 per turbine paid to the host site) for expected future green tag revenues. This payment was originally forecast to be 3.5¢/kWh based on estimated production over 10 years, but actual turbine production has been lower than expected based on manufacturer specifications, and not all green tags have been sold.

Project siting and metering

Interconnected on customer side of the meter.

Factors in ensuring project success

- Ability to leverage multiple funding sources to decrease owner payback period by 80%.
- As OWC members, host sites received benefits of extensive technical, organizational, and administrative services through local partner organizations.

Key stakeholders

- Project sponsors/developers: Northwest SEED, Northwest Cooperative Development Center, Climate Solutions, Last Mile Electric Cooperative.
- Project funders: see Initial Funding Sources below.
- Project hosts/OWC members: (10 rural households).

Capital & installation costs

$44,000 per turbine

Operational costs (annual)

Unknown

Duration of project construction/installation

February 2003 through September 2006.

Initial funding source(s)

- Multiple USDA grants totaling more than $225,000 to support OWC start-up, feasibility studies, marketing and outreach, business plan development, and construction.

- U.S. Department of Energy's NREL grant of $300,000 to support site development, outreach and field data collection.
- Montana Department of Environmental Quality low-interest loan and $5,000 grant to support MT sites.
- Bonneville Environmental Foundation no-interest 10 year loan of $60,000 ($6,000 per site), set up as prepayment for expected future green tag sales revenues.
- Site host contributions ($89,000 as of 12/31/04 – includes 6 sites).
- Utility support: 1) Northwestern Energy contributed $35,000 for MT sites; 2) Klickitat Public Utility contributed $3,125 for one WA site and 3) Seattle City Light funding totaling $20,000 for WA sites.
- Bergey Windpower discount of $7,000 per system.
- NRG Systems discount of 35% on data logging equipment.
- In-kind support (technical and legal assistance, training, etc.) from a number of individuals and organizations.

Ongoing funding source(s)

- Green Tag revenues to OWC (used to repay BEF's loan):
  - Each tag is worth 1000 kWh of renewable energy production.
  - Puget Sound Energy (PSE) bought all Washington-produced tags produced from 2004-2006 at a price of $70/tag (7¢/kWh).
  - Tag purchase agreement will have to be renegotiated with PSE next year upon expiration of original purchase agreement.
  - No buyer for Montana tags has been found; OWC does not have ownership of tags produced by 2 turbines, one located in Washington and one located in Montana. Those sites are participating in utility incentive programs that require the producer to relinquish the rights to their tags to the utility.
- Host sites in Washington are also able to receive revenues from the state's new feed-in tariff (originally there was some controversy over whether they would be eligible, but that has been resolved in the owners' favor).

kWh (annual)	**Capacity factor**
Average of 10,000 kWh per system	11.5%

Utility buy-back rate (if applicable)

Net metered

Payback

Average landowner payback is 10 years with cost-sharing (from grants, manufacturer discounts, other support) offered by OWC. Average payback w/out cost-sharing is 56 years.

Description of installed equipment

10kW Bergey Excel wind turbine, tower, wiring kit and GridTek inverter.

Project goals

- Establish a cooperative business model for rural renewable energy production, economic development, and community ownership.

- Build consumer familiarity with small wind turbines in rural communities.
- Assess regulatory, financial, and technical challenges facing development of small wind turbine networks.
- Explore potential for green tag markets to provide revenue for customer-sited small wind projects, and serve as linkage between rural and urban communities.
- Develop innovative and collaborative financing solutions that combine grants, loans, utility incentives, and manufacturer discounts.

Project history

- OWC project was launched in 2002 as collaborative between Northwest SEED, BEF, Northwest Cooperative Development Center, the Last Mile Electric Cooperative, Climate Solutions, and other nonprofits. The cooperative business model was seen as way to overcome barriers to customer-owned renewables and provide a mechanism for aggregating community resources, by creating a larger market presence than that offered by individual system owners, and promoting local buy-in.

Role played by the electric utility

For most projects, the utility agreed to grant ownership of the green tags to the system owner, except for the two turbines, one in Washington and one in Montana. Chelan PUD and Northwest Energy required green tag ownership as a condition of its financial incentives.

Obstacles encountered

OWC faced a number of challenges implementing the green tag revenue model:

- Finding premium green tag buyers has been difficult. OWC does not have adequate staffing to support an extensive marketing and sales effort. Also, the commercial price for green tags is significantly lower than the OWC price, and commercial tags are available in greater quantities. Grove recommends having an experienced sales and marketing staff person who can devote the necessary time to finding buyers.

- There are high transaction costs associated with the green tag sale transaction: Green-e certification, verification/auditing, reporting, and contract negotiations. Finding a single buyer for all tags is one way to reduce transaction costs, and negotiating a long contract term is another. Some community wind projects implementing green tag sales are seeking to match the PPA term (10-20 years) with the green tag sales agreement term, but it can be difficult to find a long-term buyer given REC market volatility.

- Turbines have produced less energy than originally expected.

- In general, the green tag aggregation/sales model as implemented by OWC has worked out, but has been more complex and labor-intensive than expected. Grove describes the Northwest Solar Cooperative (NWC) model as potentially easier to implement. NWC negotiated up front green tag purchase agreements with third parties (BEF and 3 Phases Energy) based on the number of system owners expected to sign on to the program. NWC approaches owners of small installed solar or wind systems (10 kW or less; owners must have retained rights to their green tags) and enlists them in selling tags to NWC for periods of 3-5 years. NWC's offering prices have ranged from 10¢/kWh (BEF) to 5¢/kWh (3 Phases).

8.2. Carbon offset market models

According to Holt (2005), because carbon offset markets are not regulated there may be fewer restrictions on market participation by renewable energy projects (as compared with REC markets or emissions allowance markets), but for the same reason these markets are "generally weak and illiquid." If a renewable energy generator is participating in a REC market or otherwise assigning the environmental attributes of renewable power generation to another party, he/she could not also participate in a carbon offset market and receive double "credit" for the same activity. But in the case of anaerobic digesters, there is opportunity to participate in multiple markets: REC markets for the non-energy attributes of renewable power generation, and carbon offset markets for reducing methane emissions that would occur under an alternative manure management strategy. The community digester owned by the Port of Tillamook Bay (see Section 3.2) currently sells green tags and is in the process of having carbon offsets certified by the Chicago Climate Exchange. In cases where a generator has a choice regarding which market to participate in, REC markets currently offer much higher value on a $/kWh a basis.

Carbon offset markets do present a opportunity to all potential customer-sited renewable generation projects because, unlike RECs, carbon credits can only be sold if they meet the criterion of "additionality"—that is, the revenue generated through sale of the credit makes an otherwise unviable project viable. For example, in the case of a community wind project in which the revenue stream of electricity sales does not, by itself, merit the capital investment required to develop a project, if the sale of the carbon offset credits associated with the project allow the project to cross the "tipping point" to financial viability, the carbon credits are therefore "additional" and may provide the revenue necessary to make an otherwise unlikely project a reality.

Environmental Credit Corp. (ECC) is a brokerage organization that aggregates carbon offsets produced by customer-owned renewable energy projects (primarily agricultural anaerobic digesters) and non-energy-related methane reduction and carbon sequestration projects. ECC is a registered Offset Aggregator with the Chicago Climate Exchange, which requires aggregation for projects involving less than 10,000 metric of CO_2 equivalent per year. According to ECC president Scott Subler (2006), the company finds that the carbon offset market offers better long-term value for the company than the REC market because they do not have to contend with state-specific regulatory requirements and carbon offsets typically have a longer shelf life than RECs. (Carbon trading frameworks are generally set up so that participants can "bank" offsets in expectation of higher future values—this is partly done to encourage carbon emissions reduction projects to be undertaken sooner rather than later.)

For eligible projects, ECC sets up a long-term (typically 10-year) partnership agreement with the project owner. The owner pays no money up front, and ECC undertakes all of the up-front project development work including: registering the project with the Exchange; monitoring, certifying, and registering the offsets created; coordinating verification by an independent auditor; and orchestrating the trade on the CCX trading platform. Under the terms of the partnership agreement, ECC is entitled to between 50 to 85 percent of the proceeds from the offset sale, typically demanding a higher percentage to balance the higher per-offset cost of smaller projects (Subler 2006). Project owners can elect to receive their portion once the trade is executed and the proceeds are deposited in ECC's account (which is the option chosen by most owners), or can elect to participate in ECC's Partner Credit Pool. Participation in the pool is like owning stock: when the value of a carbon offset increases, the value of a Partner Credit Pool ownership share appreciates.

The Exchange is currently trading around \$4.20-\$4.25 per metric ton CO_2 equivalent, and has been as high as \$5. According to an April 2006 presentation by ECC's Vice President of Business Development (Jensen 2006), a 1,500-cow dairy has an estimated earning potential of 5 credits per cow, where a credit is equal to one metric ton of CO_2 equivalent. Selling these 7,500 credits at April's trading price of \$4 per credit would net the farm a one-time payment of \$15,000 under its 50 percent partnership agreement with ECC. ECC currently has partnership agreements with a number of Wisconsin dairies as well as the Port of Tillamook Bay (Subler 2006).

8.3. Emissions allowance market models

Emissions allowance markets are the least-developed in terms of their potential to provide revenue streams for customer-owned renewable energy products. As mentioned above, some programs specifically prohibit renewable energy projects from participating in emissions cap-and-trade markets through the allocation of allowance. A few states with NOx cap-and-trade programs have allowed renewable projects to apply for allowances, but Maryland is one of the few states where renewable generation has applied for and received allowances (Holt 2005). In the case of the Maryland project, a commercial-scale wind project applied for and received allowances which were then retired (not sold) as part of the state's SIP compliance efforts.

In 2005 the EPA finalized the Clean Air Interstate Rule (CAIR) governing NOx and SO_2 emissions across 28 states including Wisconsin. States must revise their SIPs accordingly, and last summer the State of Wisconsin published a draft rule (AM-03-06) which is currently in the process of being finalized.[†††††] As currently drafted, the Wisconsin rule establishes a set-aside for renewable energy generation of 25 MW or greater, allowing the possibility for smaller projects to aggregate to attain this threshold. Though it will likely be many years (2015 or later, according to Wheeler et. al. 2006) until new renewable generating units are eligible to receive allowances through the program, the state cites a number of benefits of allowing renewable generating units to participate (Hassett 2006):

- Creates a mechanism for new renewable energy generating units to offset higher costs through the sale of allowances.
- Creates an additional compliance mechanism for electric generating units, by enabling them to receive allowances for developing a renewable project.
- Decreases the cost of allowances by promoting renewable energy development and reducing demand for allowances.

Though the draft rule entitles renewable generating units to receive allowances, renewable energy advocates point out that the rule would be stronger if it established a set-aside of allowances that were specifically designated for new renewable energy or energy efficiency projects (Wheeler et. al. 2006).

††††† The draft rule (July 2006) is available at: https://apps4.dhfs.state.wi.us/admrules/public/Rmo?nRmoId=609. Comments regarding the draft rule by Clean Wisconsin, the Sierra Club, and RENEW Wisconsin (October 2006) available at: http://www.sierraclub.org/cleanair/sips/CAIR_CleanWI_Sierra_RENEW%20_FINAL.pdf

This page deliberately left blank.

References

John Bahr, board member, RENEW Wisconsin (November 28, 2006). Personal communication.

Galen Barbose, Ryan Wiser, Mark Bolinger (February 2006). *Supporting Photovoltaics in Market-Rate Residential New Construction: A Summary of Programmatic Experience to Date and Lessons Learned*. Available at: http://eetd.lbl.gov/ea/emp/reports/59299.pdf

Mark Bolinger (May 2001). *Community Wind Power Ownership Schemes in Europe and their Relevance to the United States*. [LBNL-48357]. Available at: http://eetd.lbl.gov/ea/emp/reports/48357.pdf

Mark Bolinger, Ryan Wiser, Tom Wind, Dan Juhl, Robert Grace (July 2004). *A Comparative Analysis of Community Wind Power Development Options in Oregon*. Available at: http://www.cleanenergystates.org/library/Reports/OR_Community_Wind_Report.pdf

Mark Bolinger, Lawrence Berkeley National Laboratory (November 9, 2006). Personal communication.

California Energy Commission (July 2004). *Accelerated Renewable Energy Development*. Available at: http://www.energy.ca.gov/2004_policy_update/documents/2004-08-27_workshop/2004-07-30_100-04-003D.PDF

Eric Carlson, Executive Director, Carbonfund.org (November 9, 2006). Personal communication.

Mike Casper, Microgy. (December 4, 2006). Personal communication.

Jill Cliburn, (November/December 2006). *American Public Power Magazine*, "Lakeland's Solar Roofs." Available at: http://www.appanet.org/newsletters/ppmagazinedetail.cfm?ItemNumber=17871&sn.ItemNumber=2108

Jill Cliburn, ElectricSUN (November 3, 2006). Personal communication.

Jack Crider, General Manager, Port of Tillamook Bay (December 11, 2006). Email communication.

Alan Cowan, Renewable Energy Program Manager, Energy Trust of Oregon (November 6, 2006). Personal communication.

George Crocker, North American Water Office (November 1, 2006). Personal communication.

Jeff Curry, Alternative Energy Coordinator, Lakeland Electric (November 7, 2006). Personal communication.

Dane County Department of Administration (October 23, 2006). *Request for Proposals: Dane County Community Manure Management Feasibility Study*. Available at: http://www.danewaters.com/management/pdf/MMRFP.pdf

Database of State Incentives for Renewables and Efficiency (DSIRE). Available at: http://www.dsireusa.org

Mark Daugherty, MSB Energy Associates (November 28, 2006). Personal communication.

Mark Daugherty (May 2006). *Solar Electric System Marketing, Finance, Sales, and Installation*. Analysis funded by We Energies and Focus on Energy.

Jennifer DeCesaro, Project Director, Clean Energy States Alliance (November 6, 2006). Personal communication.

John Dunlop, American Wind Energy Association (November 28, 2006). Personal communication.

Noel Fenlon and Scott Debenham (August 2004). Proceedings from the conference, *Energy 2004, The Solutions Network*. “Federal Bureau of Prison’s ESPC – FCI Victorville.” Available at: http://www.energy2004.ee.doe.gov/pdf/af-5-fenlon-debenham-handout.pdf

Teresa Galluzzo and David Osterberg, The Iowa Policy Project (March 2006). *Wind Power and Iowa Schools*. Available at: http://www.iowapolicyproject.org/2006docs/060307-WindySchools.pdf

Kristen Goland, Massachusetts Technology Center (December 5, 2006). Email communication with Tom Michelman, Boreal Renewable Energy Development.

Sue Gouchoe, North Carolina Solar Center (November 9, 2006). Personal communication.

Jennifer Grove, Program Director, Northwest Sustainable Energy for Economic Development. (December 7, 2006). Personal communication.

Jan Hamrin, Dan Lieberman, Meredith Wingate, Center for Resource Solutions (March 2006). *Regulator’s Handbook on Renewable Energy Programs and Tariffs.* Available at: http://www.resource-solutions.org/policy/TariffHandbook/Handbook_on_Renewable_Energy_Programs_&_Tariffs.pdf

Scott Hassett, Secretary (July 20, 2006). *Memo to the Natural Resources Board*. “Background Memo for Hearing Authorization for Creation of Chapter NR 432 specifying the process of allocation of NOx allowances for the Clean Air Interstate Rule NOx Annual Trading Program and the NOx Ozone Season Trading Program.” [File ref. 4516-8]. Available at: https://apps4.dhfs.state.wi.us/admrules/public/Rmo?nRmoId=609

Alden Hathaway, Debra Jacobson, and Colin High on behalf of the National Renewable Energy Laboratory (May 2005). *Model State Implementation Plan (SIP) Documentation for Wind Energy Purchase in State with Renewable Energy Set-Aside*. Available at: http://www.eere.energy.gov/windandhydro/windpoweringamerica/pdfs/wpa/sips_model.pdf

Peter Hildebrandt (January/February 2006). *Distributed Energy: The Journal for Onsite Power Solutions*. “Star Dairy’s Fast Biogas.” Available at: http://www.gradingandexcavation.com/de_0601_star.html

Ed Holt and Lori Bird, National Renewable Energy Laboratory (January 2005). *Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges*. [NREL/TP-620-37388]. Available at: http://www.eere.energy.gov/greenpower/resources/pdfs/37388.pdf

Ed Holt, Ryan Wiser, Mark Bolinger (April 2006). *Who owns Renewable Energy Certificates? An Exploration of Policy Options and Practice.* Available at: http://www.resourcesaver.org/file/toolmanager/CustomO16C45F69073.pdf

Jim Jensen, Environmental Credit Corp. (April 2006). Presentation at the 2006 AgSTAR National Conference, Madison, Wisconsin. *Carbon Credits: New Opportunities for the U.S. Livestock Industry*. Available at: http://www.epa.gov/agstar/pdf/conf06/jensen.pdf

Julia Judd, Solar Electric Power Association. (September/October 2006). *California Builder Magazine*, “The Solar Factor.” Available at: http://www.cabuilder.com/internal.asp?pid=290

Dan Juhl, DanMar & Associates (November 6, 2006). Personal communication.

Jonathan Klein, The Topline Strategy Group, and Robert Erlichman, Sunlight Electric (2006). *What the Solar Power Industry Can Learn From Google and Salesforce.com*.

Joseph Kramer, Resource Strategies, Inc. (September 2004). *Agricultural Biogas Casebook*.

Larry Krom, L&S Technical Associates/Focus on Energy (November 17, 2006). Personal communication.

Charles Kubert, Environmental Law & Policy Center (2004). *Community Wind Financing Handbook*. Available at: http://www.elpc.org/documents/WindHandbook2004.pdf

Madison Gas & Electric Company (November 28, 2003). *Technical and Economic Feasibility Study Using Dairy Manure for Renewable Energy,* prepared by Virdigen LLC and Bioenergy & Environmental

F. T. McCarthy (December 10, 2005). *The Economist*, "Sunrise for Renewable Energy?" Available at: http://www.nthpower.com/press/EconSunrise.pdf

Dan McGuire, American Corn Growers Foundation (November 7, 2006). Personal communication.

Tom Michelman, Boreal Renewable Energy Development (November 16, 2006). Personal communication.

Dana Morin, Fourth Generation Capital & Scotian WindFields (November 16, 2006). Personal communication.

Mary Myers and Chris Deisinger (November 2005, revised June 2006). *Developing a Community Manure Digester Model for Wisconsin*. Available at: http://www.focusonenergy.net/data/common/dmsFiles/W_RW_RPTE_DevelCommManureDigesforWI.pdf

New Jersey Board of Public Utilities (April 12, 2006). *Press Release*, "New Jersey Leads the Nation with Expanded Commitment to Solar and Clean, Renewable Energy." Available at: http://www.njcleanenergy.com/html/5library/pr_expndd_cmmtmnt.html

New Mexico Climate Change Advisory Group (December 2006). *New Mexico Climate Change Action Plan: Final Report*. Available at: http://www.nmclimatechange.us/ewebeditpro/items/O117F10150.pdf

New York State Research and Development Authority (NYSERDA) web site (accessed November 28, 2006). *About New York's Renewable Portfolio Standard*. Available at: http://www.nyserda.org/rps/about.asp

Nova Scotia, Canada (Updated August 9 2006). Web site, *Community Economic Development Investment Funds, Histor*y. Available at: http://www.gov.ns.ca/econ/cedif/default.asp

Chamomile Nusz, Executive Director, Citizens Energy Cooperative of Wisconsin (November 28, 2006). Personal communication.

Public Service Commission of Wisconsin (September 12, 2006). *Application of Wisconsin Power and Light Company for Approval to Change Retail Electric Rates and Natural Gas Rates* (Docket No. 6680-UR-115). "Testimony of Michael J. Vickerman on Behalf of RENEW Wisconsin."

John Reindl, Recycling Manager, Dane County Department of Public Works. (November 15, 2006). Personal communication.

Sarah Rich (February 6, 2007). *WorldChanging*, "Skystream Residential Wind Turbines: An Interview with Frank Greco." Internet source. Available at: http://www.worldchanging.com/archives/006022.html

Heather Rhodes-Weaver and Jennifer Grove, Northwest Sustainable Energy for Economic Development (March 30, 2004). *Our Wind Co-op: Exploring Joint Green Tag Financing and Marketing Models for Energy Independence*. Available at: http://www.ourwind.org/windcoop/pdfs/AWEA_Paper.pdf

Scotian WindFields (Copyright 2006). Web site. Available at: http://www.scotianwindfields.org/index.php/article/frontpage/1

Wes Slaymaker, Director of Wind Energy Development, EcoEnergy LLC (November 14, 2006). Personal Communication

Gary Stern (July/August 2005). *EnergyBiz Magazine*. "ESCOs Adapt to New Realities." Available at: http://energycentral.fileburst.com/EnergyBizOnline/2005-4-jul-aug/ESCOS_070805-16.pdf

Scott Subler, President, Environmental Credit Corp. (December 4, 2006). Personal communication.

U.S. Government Accountability Office (September 2004*). Renewable Energy: Wind Power's Contribution to Electric Power Generation and Impact on Farms and Rural Communities*. [GAO-04-756]. Available at: http://www.gao.gov/new.items/d04756.pdf

Ken Valley, President, Midwest Wind Energy Finance (November 6, 2006). Personal communication.

Michael Vickerman, Executive Director, RENEW Wisconsin (November 17, 2006). Personal communication.

Elizabeth Wheeler, Carla Klein, and Michael Vickerman (October 9, 2006). *Memo to the Natural Resources Board*. "Comments of Clean Wisconsin, the Sierra Club and RENEW Wisconsin Regarding Rule AM-03-06 (Creating NR 432 to Implement the Clean Air Interstate Rule)." Available at: http://www.sierraclub.org/cleanair/sips/CAIR_CleanWI_Sierra_RENEW%20_FINAL.pdf

Don Wichert, Director, Renewable Energy Programs, Wisconsin Energy Conservation Corporation (November 17, 2006). Personal communication.

R. Wiser, M. Bolinger, P. Cappers, and R. Margolis (January 2006). *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*. [LBNL-59282].

John Young (October 2006). *Alternative Energy: Third Party Financing and Development*. Analysis funded by Focus on Energy. Available at: http://www.focusonenergy.com/data/common/dmsFiles/W_RW_RPTE_AltEnr3rdPrtyFinDevJYoun%20.pdf

This page deliberately left blank.