Advanced Renewable Tariffs for Wisconsin

Analysis and Case Study

University of Wisconsin Madison
Energy Analysis & Policy Certificate Capstone Project

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6/11/2009

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ART is a policy which aims to encourage customer-sited development of renewable energy. An ART is unique because a regular customer becomes the producer (who we will refer to as a Renewable Power Producer (RPP)), and the electric utility becomes the customer. This is different than net metering and a RPS; net metering is essentially running the kWh meter backwards—thus, the value for a kWh of renewable electricity is equal to the retail rate—while a RPS establishes a quantity obligation.

There are many ways to establish energy payments for an ART. The various methods are primarily based on:

1. Generation cost, which provides a payment based on the cost of the technology
2. Avoided cost, which sets the payment based on displacing fossil fuel-based generation
3. Premium rates, which establish energy payment at a specified level above the retail rate for electricity

This analysis uses a generation cost approach—generation cost is the most common form and is consistent with the Governor's Task Force on Global Warming—to determine energy payments for each renewable technology. Tariff energy payments are established to provide an RPP with a 12.5 percent internal rate of return on equity, where the RPP pays for 20% of the installation with equity and the remainder with a combination of debt and tax incentive. The energy payments are determined for solar photovoltaics, wind, biomass, and biogas. Section 2 discusses policy issues associated tariff design.

We used RETScreen International, a Microsoft Excel-based modeling software, to calculate energy payments. Our assumptions were shaped largely by existing ARTs (e.g., the German feed-in tariff law), the Global Warming Task Force recommendation, and stakeholder comments to the Wisconsin Public Service Commission docket (5-EI-148) on advanced renewable tariffs. Stakeholder concerns are addressed in much greater detail in Section 3. The following table outlines the ART payment levels established for our Example Wisconsin ART case study:

Energy Payments

•Energy payments designed to provide rate of return comparable to utilities allowed rate of return

	$/kWh	Project Size	Program Cap
Biomass	$0.430	< 5 MW	2.75% of retail sales
	$0.150	5MW < 15 MW	
Biodigester	$0.126	< 200 kW	
	$0.070	> 200kW	
Solar	$0.53	< 10kW	0.25% of retail sales
	$0.499	10 < 100kW	
	$0.47	100 < 500kW	
	$0.43	> 500kW	
Wind	$0.232	< 20kW	
	$0.146	20 < 100kW	
	$0.127	100kW < 1MW	
	$0.089	> 1MW	

Introduction

A renewable energy tariff (also referred to as a feed-in tariff (FIT) or advanced renewable tariff (ART)) is the most prevalent renewable energy policy design in the world. As of 2007, Chinese and Canadian provinces and 40 countries in total, including 18 European Union (EU) countries, have adopted renewable tariff policies (Rickerson, Sawin, and Grace, 2007). The United States does not have a renewable energy policy at the federal level: states have responded to this lack of policy by establishing Renewable Portfolio Standards (RPS). The primary difference between a renewable tariff and a RPS is that a renewable tariff sets a price and lets the market determine quantity, while an RPS sets a quantity target and then lets the market determine price.[1]

ARTs have driven explosive renewable energy capacity growth in Europe in the last two decades. In time, the policies have changed as experience has accumulated. The term "feed-in tariff" is slowly being replaced by "advanced renewable tariff", or ART, which we will use henceforth in our analysis. Another difference between the two is that an ART implies price differentiation by technology, while it still maintains its feed-in provisions.

One difficulty in the development of an ART compared with a renewables obligation, such as an RPS, is the attribution of a specific payment amount, structure, or duration. All three require decisions based on a large amount of economic and political conditions and assumptions. Long-term forecasting is often imprecise and inaccurate, which can create unwanted risk on behalf of energy investors (Lesser and Su, 2008). On the other hand, ARTs have been proven to be an effective policy mechanism to encourage renewable energy development and have been increasingly argued as a comparatively cost-effective and superior renewable energy policy (Stern Review, 2008).

In this handbook, we aim to identify policy objectives associated with developing ARTs in Wisconsin. We will refer to Germany as our main case study because Germany: (1.) has the most effective existing renewable tariff policy in the world; (2.) is currently meeting 75 percent of the EU's

[1] From here on, we will refer to a renewable energy tariff as an Advanced Renewable Tariff, or ART.

Kyoto Protocol greenhouse gas reduction obligations (Office of the Federal Government of Germany, 2009); (3.) has renewable resource characteristics similar to Wisconsin's. Additionally, we will identify stakeholder concerns, which were taken from the comments of the Public Service Commission of Wisconsin (PSCW) docket on advanced renewable tariffs. Lastly, we will calculate the energy payments necessary for various renewable technologies in Wisconsin to meet the Task Force's[2] generation cost-based[3] ART policy recommendation.

[2] Task Force refers to the Wisconsin Governor's Task Force on Global Warming

[3] Generation cost-based approach means that ART participants (renewable power producers) will be paid a sufficient amount to recover the costs of their generation system plus a rate of return similar to utilities rate of return.

1. What is an Advanced Renewable Tariff?

ART is a policy which aims to encourage customer-sited development of renewable energy. An ART is unique because a regular customer becomes the producer (who we will refer to as a Renewable Power Producer (RPP)), and the electric utility becomes the customer. This is different than net metering and a RPS; net metering is essentially running the kWh meter backwards—thus, the value for a kWh of renewable electricity is equal to the retail rate—while a RPS establishes a quantity obligation.

The underlying purpose of an ART is to encourage small, local generation, thus making renewable energy an economic development opportunity and local job creation strategy. Energy is used where it is produced, so there is potential for less wasted energy lost from transmission, less financial investment in transmission, and more money that is circulated within a particular region. In many ART designs, prices paid to the RPP go down over time (digression). Digression means that if a RPP installs a renewable energy system this year, that producer will get a fixed energy payment over a certain number of years. If another RPP installs the same system next year, the producer in the next year will get an energy payment that is less. This has two important consequences: (1.) it encourages investors to "get into the game" quickly and (2.) it encourages product innovation because companies that produce renewable energy systems, such as solar panels or wind turbines, have to continually find new efficiencies to drive down costs.

<u>The German ART</u>

Germany has had a price-based national renewable energy policy since 1990, and an ART since 2000. At the time, its goal was to double renewable electricity production by 2010. This goal was met by 2007. Wind provides the largest share of Germany's generation, with over 40 million MWh generated in 2007. Wind constitutes over six percent of electric generation. Additionally Germany has produced approximately 16 million MWh of biomass electricity and 2.2 million MWh of PV electricity, as of 2006 (Germany Ministry of the Environment, 2007). The case in Germany is particularly interesting with solar because Germany does not receive much sunlight. It gets less solar energy on an annual basis than Wisconsin, but it has about 5 GW of installed PV capacity which accounts for over half the world's PV generation (53 percent). Additionally, over 300,000 people are employed in the renewables sector in Germany. By 2010, this number is likely to double, and renewable energy is likely to become the largest employer in Germany.

2. ART Policy Design

2.1 Technology

A question that should be addressed in the design structure is how long-term goals, such as the rate of technological progress in the state, will be aligned with short-term goals, such as market penetration. Granting fixed, long-term contracts to already or nearly competitive technologies is inefficient. Likewise, granting such payment amounts to more speculative, less-developed technologies is likely to create underinvestment in societal benefits over the duration of an ART contract.

Thus, the technology objective is to:

- ensure that each technology gets the best chance of developing,
- prevent large profits for technologies that require comparatively minor incentives, and
- ensure ratepayers do not subsidize technologies that will be cost-competitive in the short term.

Category 1. Renewable energy applications currently cost effective under ideal circumstances in Wisconsin include:

Large-Scale Wind

Wind farms with utility-scale turbines are usually installed by developers or utilities, but individual turbines can be erected through community wind projects. Turbines sized up to 1.5 MW are included in this study as potentially customer-sited.

Small-Scale Solar Hot Water Electric

Solar water heating to augment an electric residential water heater is often cost-effective based on the value of displaced electricity consumption. During Wisconsin winters, a solar water heater can provide 30 to 40 percent of hot water requirements, and an even higher percentage in summer. With appropriate solar access, solar pool heaters for seasonal outdoor pools are highly cost-effective in Wisconsin.

Category 2. The second group of renewable energy applications includes those that have gained popularity despite the fact that they are not cost-effective, at least from an investor's perspective. Reasons for adoption of these technologies include reducing emissions of greenhouse gases and other pollutants, making a visible commitment to clean energy, securing a hedge against future energy prices, creating jobs, and encouraging technologies not likely to be developed under a RPS. Category 2 includes:

Solar Photovoltaics

Solar PV systems have become popular among home owners, small businesses, schools, churches and municipalities in Wisconsin. Despite the long payback for these systems, they have become a primary symbol of commitment to clean energy, and Focus on Energy is experiencing high demand for solar PV incentives.

Small-Scale Wind

Residential-scale wind turbines (less than 100 kW) continue to be attractive to rural property owners, both for reasons similar to those for buying solar PV, and for energy self-reliance in isolated locations.

Biomass Combined Heat and Power (CHP)

These technologies can burn wood, crop waste, or other organic matter to generate electricity and heat. Applications of biomass CHP are most economical where space or process heat is needed and electricity is a secondary product, such as in industrial processes. Close proximity of the fuel is important to ensuring economic viability.

Biogas

Methane gas collected from anaerobic digesters and landfills can either be burned in combustion devices or piped. In order to be injected into existing natural gas pipelines, biogas has to be cleaned of abrasive chemicals, which requires improvements of current technology and establishing acceptable utility standards and interconnection rules. Combustion of biogas in a generator engine or microturbine can produce heat and electricity.

Category 3. The third category includes technologies with limited or problematic development potential in Wisconsin. These applications are unlikely to make a significant contribution to renewable energy in the state. An example is tidal power.

Category 2 represents the goals and objectives of an ART; thus PV, wind, biomass, and biogas are chosen to be the technologies included in our analysis.

2.2 Price

The most common ART design structure is a guarantee of a long-term (20 years, for instance) minimum price for generated electricity. The advantage of a fixed-price incentive is to provide to renewable energy developers a degree of financial stability and a hedge against future energy market volatility. The Wisconsin Task Force on Global Warming recommends to "set technology-specific tariffs at a level which will yield a rate of return comparable to Wisconsin Investor-Owned Utilities' (IOUs) allowable returns" (WI TFGW, 2008).

There are many ways to establish energy payments for an ART, and they are primarily based on:

4. Generation cost, which provides a payment based on the cost of the technology
5. Avoided cost, which sets the payment based on displacing fossil fuel-based generation
6. Premium rates, which establish energy payment at a specified level above the retail rate for electricity

The Task Force chose to recommend a generation-cost ART, which is by far the most common methodology. Perhaps the most compelling benefit of a generation-based approach is that fixed-long-term contract alleviates risk to investors in renewable energy. Price security makes renewable energy a safe bet for banks and investors, which is why the EU has not experienced the same level of declines in new generation that has existed in the U.S.

Thus, the price objective is to:

- spur investment by guaranteeing a profit to anyone who produces renewable energy

Adjustments for inflation

Whatever the payment contract, the tariff will apply for many years. Inflation could therefore significantly impact price. With the exception of Germany, all countries we've researched make adjustments to take into account the annual inflation rate, although the rate varies.

Periodic adjustments

ARTs typically allow for periodic regular adjustments. Ontario's Standard Offer Program, for example, requires monitoring and review every three years. Periodic revisions are also provided for in the German and Spanish laws, preceded in both cases by progress reports on how the law is working. This allows for changing circumstances to be taken into account when setting the tariff rate for new installations.

2.3 Access

A key feature for the success of ARTs is the ‘‘feed-in’’ provision, or in other words, the grid access and purchase obligation for renewable electricity. The fact that the grid is required to connect renewable electricity producers and to buy all their production is one of the main elements of the success of feed-in laws. This structure guarantees the producers a steady flow of revenue, which makes financing possible for the upfront investment. However, financing options are critical because the initial investment tends to be the main expenditure in renewable electricity projects.

Another access question that should be addressed is whether the ART structure will include explicit provisions to guarantee connection and transmission of renewable electricity. To maximize the effectiveness of an ART, provisions should include the technical requirements for connection and delivery of electricity, as well as the allocation of costs for connection.

Ensuring grid access

An obligation on the distribution system operator or transmission system operator to connect eligible generators to the grid is fundamental. The legal obligation to connect can take various forms, such as a simple obligation to connect, a priority obligation to connect, and an immediate and priority obligation to connect; though sometimes it depends on an agreement.

Who pays the cost of connecting and reinforcing?

ARTs typically include provisions for cost sharing between producers and grid operators, as the costs for grid connection have an important impact on the economic viability of a project, and on how much electricity can be produced. One way is to require the RPP to pay for the costs of the equipment needed to connect their renewable installation to the grid. Thus, the utility and grid operators will pay only for electricity generated. Another way is to have the utility pay for everything. A third way is to share costs. Existing renewable buyback programs in Wisconsin exhibit the utility paying for the costs of connecting, but instead of spreading that cost across all ratepayers, the cost is recovered in the form of an expensive administrative fee for the RPP, representing a disincentive to invest in renewable energy in WI.

2.4 Rate Impacts

We were unable to do rate modeling, so we looked at Germany to see the impact of the world's most aggressive ART.

The German Case Study

Under the Germany ART, the Erneuerbare-Energien-Gesetz (EEG), the German grid operators have a priority purchase obligation to buy legally-specified renewable electricity at a guaranteed FIT. The electricity is then sold to the electricity suppliers according to their market-share. The additional cost for the FIT has to be paid by the consumers in the end.

A study by the German Ministry for the Environment concluded that the differential in annual cost for renewable electricity generation was 3.2 billion Euros, or 12 Euros per household. However, there are other benefits that exist from renewable energy generation, such as reduction in wholesale prices, avoided external costs from fossil fuel generation, and avoided energy imports. The Ministry for the Environment of Germany found that the value of these three factors was 9.6 billion Euros in 2006 (Figure 1) (Ministry for the Environment of Germany, 2007):

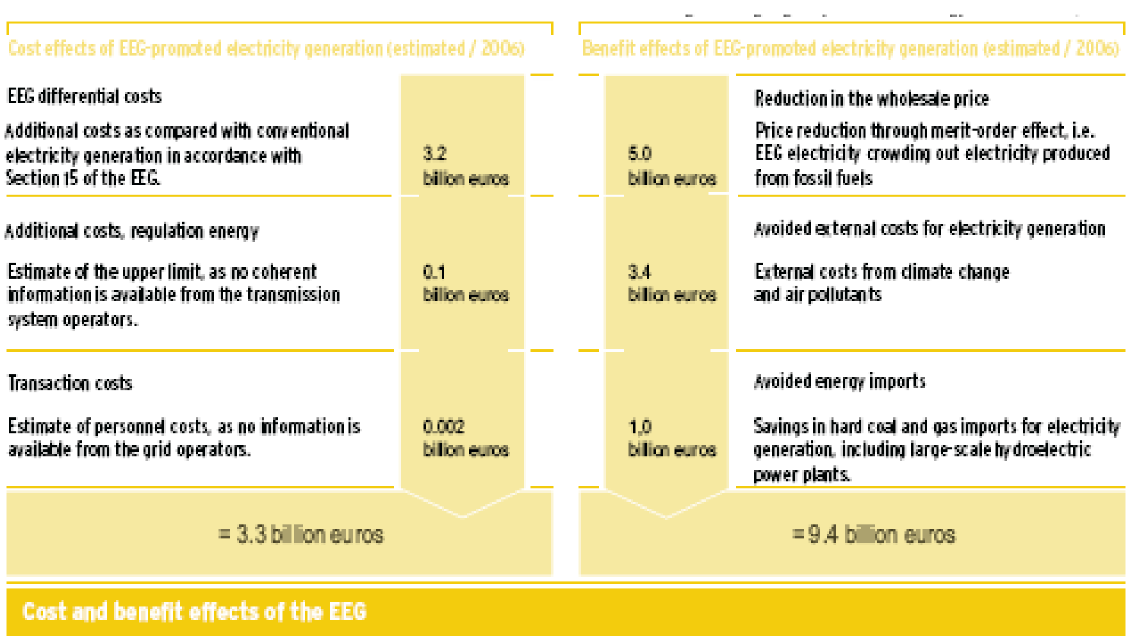

Figure 1: Cost and benefit effects of the EEG (Ministry for the Environment of Germany, 2007)

An important consideration for policymakers is the market value of the new, renewable generation which is added to the grid. Estimating the market value of this renewable electricity generation can be calculated by multiplying the electricity production by the spot market price. The demand for electricity is inelastic in the short-run (i.e. in a day-ahead market), so electricity from renewable sources has to be bought by supply companies in advance (F Sensfuß, M Ragwitz, M Genoese, 2008). Thus, demand load that would have to be purchased on the electricity spot markets at the peak is reduced with additional renewable supply. Therefore the guaranteed feed-in of electricity generated by renewable energy sources can have the effect of a reduction in both the aggregate electricity demand and the average total cost curve for electricity.

The following graphs (Figure 2) include a load curve and electricity prices for a single day in October 2006, modeled from the German EEG (F Sensfuß, M Ragwitz, M Genoese, 2008):

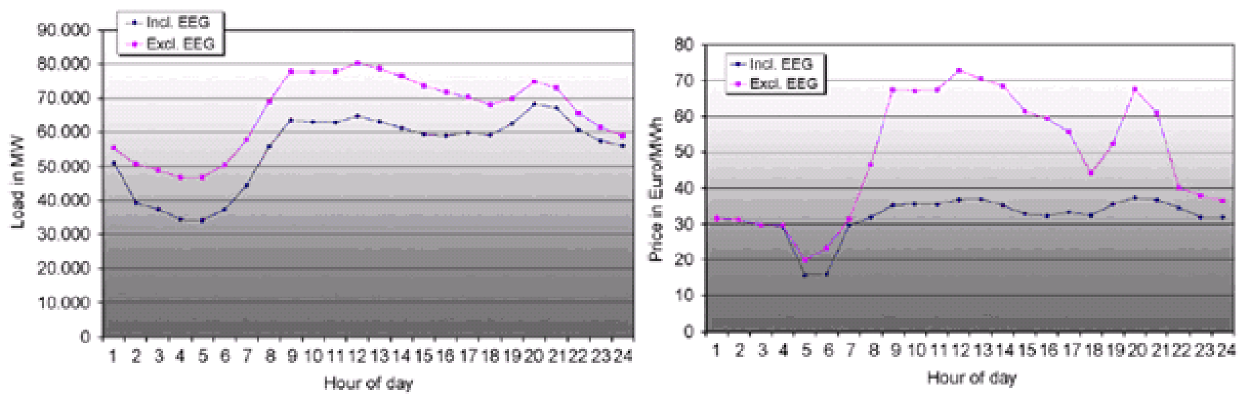

Figure 2: Comparison of Load and Prices for One Simulated Day in October 2006 (two scenarios: one including EEG-renewables, the other excluding EEG-renewables)

This simulation was for a peak demand day in Germany in October 2006. In this event, the aggregate load curve was alleviated, and the spot market prices were more stable when the RPPs sold electricity to the utility than if they had not. The modeled analysis shows that the renewable electricity generation has "a considerable impact on market prices. In the year 2006, the reduction of the unweighted average price reaches 7.8 Euros/MWh." (F Sensfuß, M Ragwitz, M Genoese, 2008)

From a strictly generation cost perspective, it can be concluded that renewable energy will cost the utility, and thus the ratepayer more money. This is because:

1. The utility has a priority purchase obligation for renewable electricity.
2. The cost of production for renewable electricity is higher than that of fossil fuels, which ultimately leads to the utility paying more.
3. This filters down to all end-users of electricity Thus, an advanced renewable tariff policy will lead to people paying more on their energy bills.

However, other benefits exist in the form of load alleviation, reduced volatility in electricity spot markets, as well as environmental benefits. Therefore, the additional costs of an ART can be defined as the cost for the renewable electricity minus the market value of the renewable generation (market value = production × spot market price). Since the utility is obligated to buy electricity from the RPPs first (i.e., the merit-order effect), the guaranteed feed-in of renewable electricity has the effect of a reduction in electricity demand. Policymakers should therefore understand all costs and benefits when evaluating an ART.

3. Summary of Responses to PSCW ART Survey–Docket 5-EI-148

3.1 ART Survey

On January 8th, 2009 the PSCW opened a new docket to perform an "Investigation on the Commission's own Motion Regarding Advanced Renewable Tariff Development (PSCW, 2009)." Jon began this investigation by distributing a survey with questions regarding whether and how to expand the availability of ARTs in Wisconsin. The contents of the survey can be broken down into three primary areas of interest – Experimental ART experience in WI, ART Policy, and ART Design Components (Figure 3).

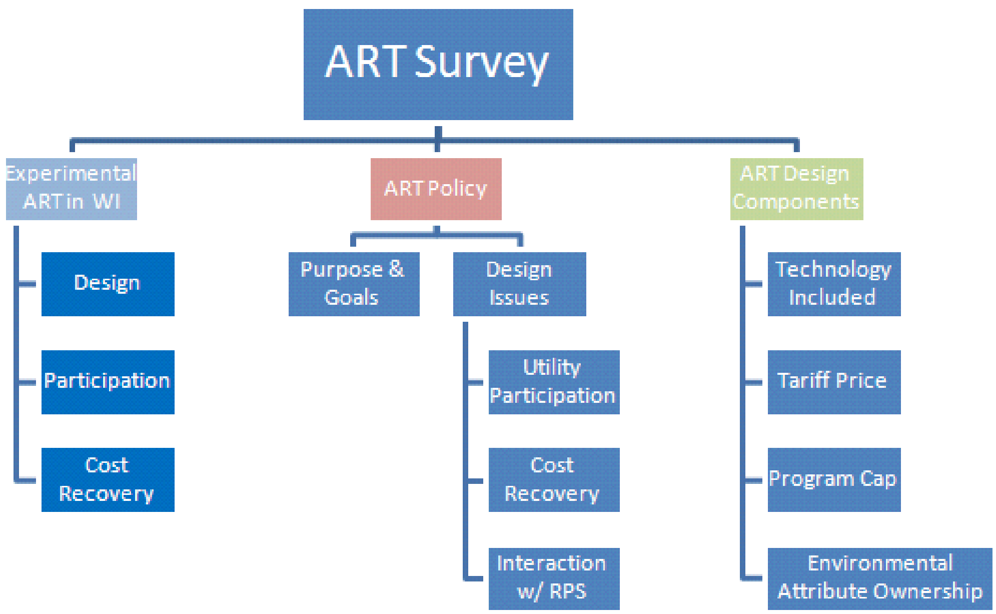

Figure 3: Major Topics Covered in PSCW ART Survey

3.2 Survey Respondents

The ART survey was mailed to recipients, presumably Wisconsin electric utilities, and opened for public comment on the PSCW website January 16, 2009. Replies were due one month from this date. The survey cover letter states that utilities are urged to respond and that it is not necessary for each respondent to answer every question. The PSCW received 31 responses from stakeholders which fall into

Advocacy

1. RENEW and Clean Wisconsin
2. WI Cast Metals Association and WI Industrial Energy Group
3. WI Dairy Business Association
4. Wisconsin Farmers Union
5. Eric Nottestad

Biodigester Business

1. AgrEnergy
2. Biomass Solution
3. Clear Horizons
4. Energies Direct
5. GHD, Inc
6. Green Valley Dairy
7. Hanusa Renewable Energy
8. Stormfisher Biogas
9. Suring Digester
10. Tiry Engineering

Government Organizations

1. Dane County Supervisors
2. Dept. of Agriculture, Trade, and Consumer Protection
3. Forest Country Potawatomi Community
4. Wisconsin Legislature Assembly on Agriculture

Utilities and Utility Assoc.

1. Cooperative Network
2. Madison Gas & Electric
3. Municipal Electric Utilities of WI
4. Northern States Power Company
5. We Energies
6. WI Electric Cooperative Assoc.
7. WI Power and Light
8. WI Public Service Co.
9. WI Utilities Assoc.
10. WPPI Energy

Figure 4: Categorical Listing of 31 Respondents to PSCW ART Survey

four categories: advocacy groups, biodigester businesses, government organizations, and utilities and utility associations. Figure 4 shows that utilities responded well to the urge for them to reply, with all of the large investor owned utilities (IOUs) replying as well as the respective associations representing the IOUs, cooperatives, and municipal electrical utilities. The other survey respondents primarily represent the interests of agriculture though, with 10 biodigester businesses, the WI Dairy Business Association, Wisconsin Farmers Union, Dept. of Agriculture Trade and Consumer Protection, and the Wisconsin Legislature Assembly on Agriculture all touting the benefits of biodigesters for the state of Wisconsin.

<u>Takeaways regarding Survey Respondents</u>

- Good representation of utilities
- Other respondents primarily represent agricultural interests
- Stakeholders related to small wind, solar, and other renewable energy technologies are generally not represented. The only respondent providing significant representation for wind and solar is Renew Wisconsin.
- Renew Wisconsin/Clean Wisconsin and the Forest County Potawatomi Community provided two of the most detailed and insightful responses

Appendix 3 provides a detailed summary of the stakeholder’s survey responses and provides links to the original documents submitted to the PSCW.

3.3 Takeaways from Survey

Review of the survey responses suggests that although stakeholders have many similar ideas as to what the broad policy goals of an ART for Wisconsin should be, when it comes to the details there are many ideas as to just how the policy ought to be designed. This section does not claim to be comprehensive; it just briefly summarizes stakeholder's input on several key aspects of ART policy.

I. *General Policy Comments*

Policy should be simple

The most consistent response from stakeholders was that the policy should be simple and easy for potential ART participants to use and understand and that the policy should not benefit renewable power producers excessively. Two design principles proposed by the Wisconsin Utilities Association do a good job of capturing this general stakeholder opinion:

1. "Keep ART design simple and easy for potential customer participants to understand."
2. "Use care in designing programs to minimize opportunities for manipulation or unintended consequences (WUA, 2009)."

Policy design should follow policy goals

Many respondents stated it was critically important to establish the goals of the policy first, and to then proceed to design a policy which reflects these goals. The overwhelming number of policy goals proposed by stakeholders however, some of which are shown below in Figure 5, suggests that just choosing the policy goals will be challenging in itself. The primary goal of an ART policy – to increase small scale renewable power generation – does stand above the policy goals of the individual stakeholders, leaving policy makers to determine which other goals are most critical.

Figure 5: Various policy goals of stakeholders

II. *Art Policy*

How are the costs of the ART distributed?

Stakeholder presented many proposals for how to pay for the costs associated with the ART. Some of the proposals were:

1. Pay for the ART exclusively through utility green pricing programs (many existing WI experimental ARTs are funded this way).
2. Distribute costs among all customer classes and equally among utilities.
3. Pay for the ART with public benefits funds.
4. Pay for the ART with the state general fund.

The recommendations fall into two categories: proposal 1 which assumes the benefits from ARTs are not important to the public so payment is by choice, and proposals 2-4 which assume the benefits from ARTs are important and distributed among the public so costs should therefore be distributed equitably among Wisconsin ratepayers.

Most stakeholders agree with the Task Force that although "Advanced Renewable Tariffs would likely result in increased costs per unit of electrical output compared to utility-scale renewable projects, …these costs are justified by the economic and environmental advantages from encouraging distributed small-scale generation (Task Force, 2008)." The main issues for policy makers are to determine the most equitable method to distribute the costs of an ART and how to minimize the impact on ratepayers most sensitive to increased costs, competitive industries and low income earners for example.

Which utilities should participate?

The general opinion is that all utilities should participate and have consistent ART policies. The electric cooperatives, since their prices do not currently fall under PSCW jurisdiction, are quick to point out the legal issues involved in mandating a state ART policy. Cooperatives are concerned that an ART ruling, whether by the PSCW or state legislature, will alter the way they are currently regulated. Utilities also point out that although an ART policy which is consistent for all utilities may seem to be the best for potential ART participants, IOUs, cooperatives, and municipal electric providers each operate very differently. Utilities suggest the best solution may be to implement several ART policies, each tailored to the individual types of utilities.

Should energy generated from the ART count towards the RPS?

Respondents in general agree that the renewable energy produced by ART participants should contribute towards the RPS. Respondents point out two problems in particular though. First, the administrative cost of tracking many small systems is substantially more expensive than the cost of tracking a few large utility scale systems. Second, the ART policy will likely put upward pressure on the costs of achieving RPS targets, and may drive up the cost of renewable energy generation as a whole.

Should the ART price reflect available incentives (Focus grants, federal tax credits, etc.)?

The Forest County Potawatomi Community, the only respondent who really addressed this topic, pointed out the Task Force electric generation group determined that other financial incentives, such as tax credits and those from Focus on Energy, should not be considered in setting ARTs since their availability over time is not guaranteed (FCPC, 2009). The federal tax credits have recently grown substantially though, with an unlimited 30% investment tax credit available to individuals and businesses installing wind or solar systems. The magnitude and near universal availability of these federal tax credits suggests, in the opinion of the authors, that the ART price should reflect these tax credits. The ART prices established in section 5 therefore include noncompetitive federal incentives, but do not include competitive incentives such as Focus on Energy grants.

III. *Design Components*

What technology should the ART include?

Respondents in general believe the most important technologies are biodigesters, biomass, solar, and wind, and this report therefore focuses on these technologies. Respondents are less clear on whether the art should include small hydro as well as landfill and sewage treatment gas used for electric generation.

What renewable energy payment structure is appropriate?

Section 2.2 addressed some of the many payment structures that may be used for an ART. Respondents in general agree that the *price level* should be set to provide a rate of return similar to utilities and that the *price structure* should be a fixed energy payment, $0.10/kWh for example, paid out for a fixed contract length. There is substantial disagreement though as to what an appropriate contract length should be though, with some stakeholders arguing that shorter contract lengths, 10-15 years, are necessary and others arguing that international ART experience has shown that only 20 year contract will be sufficient.

Respondents also point out that technologies with high operating and maintenance costs, biodigesters and biomass generators specifically, require an energy payment which is inflation adjusted to ensure financial viability. Utilities are opposed to having inflation adjusted rates though, and point out that regulatory limitations make it problematic to implement automatic rate adjustments (WUA, 2009).

How high of a program cap is appropriate?

Some respondents argue that having no program cap, as is the case in Germany, will offer the greatest benefit to Wisconsin. However, most respondents argue that the program cap should be set to maximize the benefits to Wisconsin residents. Respondents commonly stated the goal is to prevent excessive impacts on Wisconsin ratepayers, but it is challenging to determine what an excessive impact is. Renew Wisconsin and Clean Wisconsin were the only respondents to suggest a specific level for the program cap (Renew, 2009). They suggest a program cap of 3% of 2007 WI electric sales, with the cap also being distributed by technology: 2.75% for biodigesters and biomass and 0.25% for solar and wind.

Who should own environmental attributes?

Utilities and most other respondents agree that utilities should own the renewable energy attributes associated with the generation, currently traded as Renewable Energy Credits in Wisconsin. These attributes are then counted toward RPS targets for utilities. There is disagreement though as to who should own the carbon credits associated with the generation. Biodigester businesses and farms argue that they should get to keep the substantial carbon credits they receive because utilities do not need these credits, and will therefore undervalue them. There is not currently a well established price for carbon though, so our analysis assumes that farmers receive no value from them; therefore the ART price does not reflect carbon credits.

3.4 Critical Policy Attributes Used to Develop Model Wisconsin ART Policy

Stakeholders' responses to the PSCW survey, as outlined in section 3.3, were used to develop a set of critical policy attributes. These attributes, which include the actual energy payment levels that would be necessary for in Wisconsin, are outlined below in Figure 6. Section 5 will establish the energy payments and contract lengths necessary for an ART participant to earn a rate of return comparable to utilities.

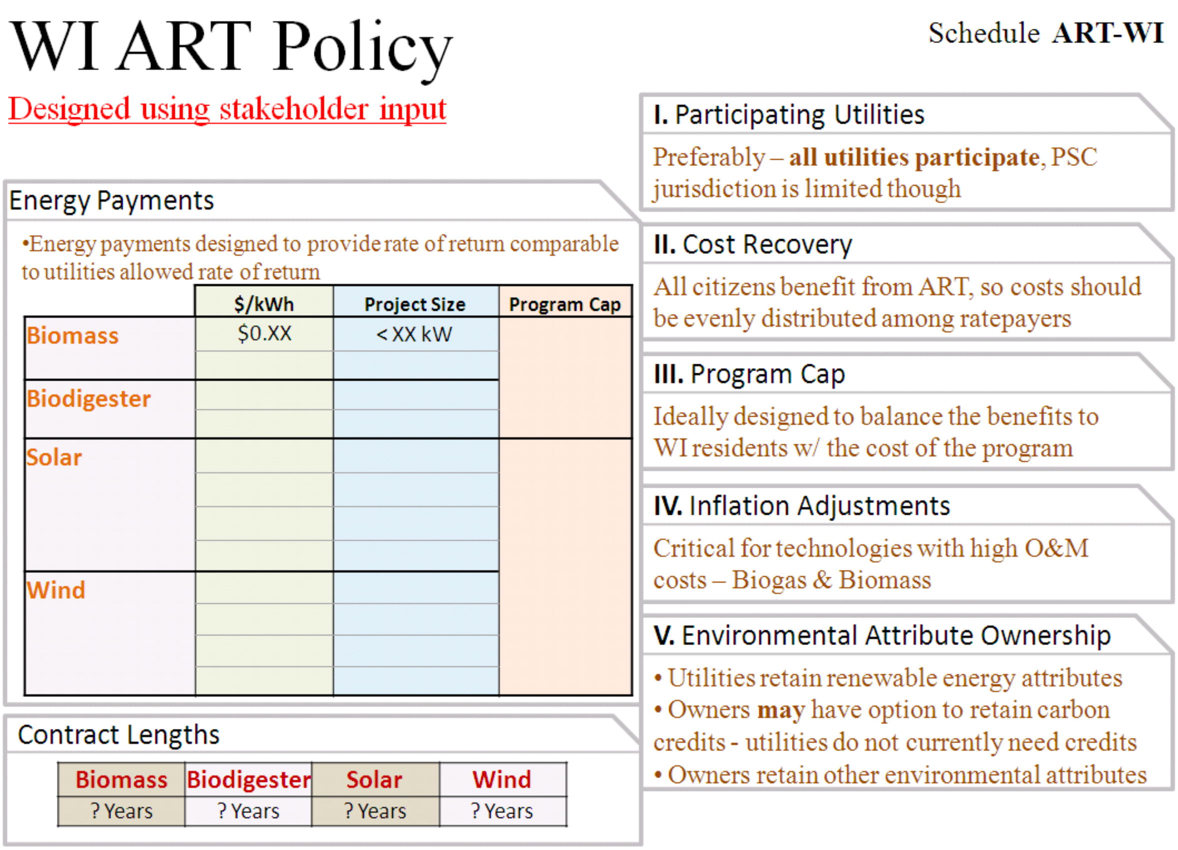

Figure 6: WI ART Policy Outline – Policy Attributes derived from PSCW ART Survey Responses

4. Evaluation of Wisconsin Experimental Arts

4.1 Experimental Arts – Proposed by Governor's Task Force

In early 2008 Wisconsin electric utilities began to include experimental ARTs in their rate schedules. The tariffs are experimental in that their characteristics vary substantially between utilities and technologies, and in that all the tariffs have a small program cap. The information gathered from these experimental tariffs will aid in the Green Tariff Study as proposed by the Task Force, which aims to study the feasibility of different renewable tariff structures for Wisconsin.

Currently the five large investor owned utilities, Dairyland Power Cooperative, and the customer owned utilities represented by WPPI Energy have established experimental ARTs. These utilities serve over 90% of Wisconsin customers, so experimental ARTs are available to most of the state's residents. However, Figure 6, shows that even though these utilities offer ARTs , the technologies covered by the ARTs varies substantially. All of the ARTs have a 10 year contract length, and their individual characteristics will be detailed in section 4.2.

Table 1: WI Utilities with Experimental ARTs

Utility	**Biodigesters**	**Biomass**	**Wind**	**Solar**
Dairyland Power Cooperative (DPC)	**X**	**X**	**X**	
Madison Gas & Electric (MGE)	**X**	**X**	**X**	**X**
Northern States Power Company (NSPW)	**X**	**X**	**X**	
We Energy	**X**		**X**	**X**
Wisconsin Power and Light (WPL)	**X**	**X**	**X**	**X**
WPPI Energy (WPPI)				**X**
WI Public Service Company(WPSC)				**X**

4.2 Comparison of Wisconsin's Experimental ART Schedules

4.2.1 Biogas and Biomass Tariffs

Table 2 below outlines the Biogas and Biomass Tariffs offered by Wisconsin utilities. Biogas and Biomass are treated similarly by many utilities, with only DPC and We Energy differentiating between the two. The tariff prices range between $0.07/kWh and $0.09/kWh, and many utilities said in the PSCW survey responses that their tariffs have several participants. Biodigester businesses have likewise indicated the tariff prices are sufficient to get some farmers to build biodigesters, 17 farmers have so far, if they also receive a competitive grant from Focus on Energy or the Federal Government.

Table 2: Experimental Biogas and Biomass Tariffs

	Biogas			Biomass				
	$/kWh	**Size**	**Cap**	**$/kWh**	**Size**	**Cap**	**CC/year***	**Schedule**
DPC	0.105 on -peak $0.054 off-peak	40kW-2MW	2MW/ Feeder	Not Certain	40kW-2MW	2MW/ Feeder	$ -	DG-5
MGE	Negotiable	> 20kW **1-phase** > 20kW **3-phase**	5 MW	Negotiable	> 20kW **1-phase** > 20kW **3-phase**	5 MW	$ 129.00 $ 201.00	PG-3
NSPW	$0.073	20kW-100kW **<200A** 20kW-100kW **>200A** 100kW < 800kW	0.25% retail sales	$0.073	20kW-100kW **<200A** 20kW-100kW **>200A** 100kW < 800kW	0.25% retail sales	$ 78.00 $ 103.20 $ 181.20	Art-1
We Energy	$0.155 on-peak $0.04 off-peak	<1000kW	10 MW				$ -	CGS 5
WPL	$0.12 on-peak $0.074 off-peak	20kW-200kW 200kW-2MW	0.5% retail sales	$0.12 on-peak $0.074 off-peak	20kW-200kW 200kW-2MW	0.5% retail sales	$ 152.42 $ 304.85	Pgs-ART

*CC/year is the additional Customer Charge per year

Biomass and Biogas Experimental ART Takeaways

- Energy payments are sufficient to achieve some participation when combined with other incentives.
- The total program cap of the five tariffs is in the range of 20MW, but with the current rate of development and cost of installing and operating a biodigester, it is unlikely these tariffs will attract full participation.

4.2.2 Solar Tariffs

WPPI and four of the five investor owned utilities have solar tariffs (Table 3). Utilities indicated that they established the tariff rate, which ranges from $0.225-$0.30/kWh, to be just high enough to spur development of solar systems. The utilities assumed that their tariff rate in combination with a Focus on Energy grant would be a sufficient incentive to get customers to participate in the tariff, although not necessarily sufficient to off any sort of reasonable payback for the installed solar PV system. These solar tariffs have been remarkably successful in promoting solar development though. MG&E and WEPCO's tariffs have already filled up, WPL expects their tariff to fill up by the end of 2009, and WPSC achieved 40kW of enrollment in just the first six weeks.

<u>Solar Experimental ART Takeaways</u>

- Solar tariffs are funded primarily through utility green pricing programs.
- The combined program cap of all the solar ARTs is 2583kW, which is enough solar capacity to supply about 0.005% of Wisconsin's annual electric energy consumption.
- WPL's customer charge is high enough that it may significantly discourage the installation of solar systems smaller than 5 or 10kW.

Table 3: Experimental Solar Tariffs

	Solar				
	$/kWh	**Size**	**Cap**	**CC/year***	**Schedule**
DPC					
MGE	$0.25	1-20kW	300kW	$ -	Pg-4
NSPW					
We Energies	$0.225	1.5-20kW	1000kW	$ -	CGS-PV
		20kW-100kW **Non-Demand**		$ 15.00	
		20kW-100kW **Demand**		$ 42.00	
WPL	$0.25	1-20kW	683kW	$ 152.42	Pgs-ART
WPPI	$0.30	< 4kW	300kW	$ 12.00	**
WPSC	$0.25	1-20kW	300kW	$ 24.00	PG-Solar

*CC/year is the additional Customer Charge per year

**WPPI's wholesale Solar PV purchase schedule combined w/ member utility schedule, River Falls Municipal Utilities Rate Schedule for example

4.2.3 Wind Tariffs

Table 4 outlines the available wind tariffs and shows that there is a lot of variability between wind tariff designs. There are four different types of energy payments and program caps:

Energy Payment Types

1. Customer's Energy Rate
2. Negotiable (MGE)
3. Fixed rate (NSPW)
4. On-peak & off-peak rate (WPL)

Program Cap Types

1. Generation cap: Percentage of retail sales
2. Capacity cap: Installed capacity
3. Technical limit: 2MW/distribution feeder
4. Number of customers

The differences in energy payment type, program cap type, and customer charge per year show that the utilities have many different ideas about how a tariff can be designed.

Table 4: Experimental wind tariffs

Wind

	$/kWh	Size	Cap	CC/year*	Schedule
DPC	CER**	< 40kW	2MW/Feeder	$ -	DG-5
	$0.065	40kW-2MW			
MGE	$0.061	< 20kW	5 MW	$ -	PG-3
	Negotiable	> 20kW **1-phase**		$129.00	
	Negotiable	> 20kW **3-phase**		$201.00	
NSPW	CER***	< 20kW		$ -	Pg-1
	$0.066	20kW-100kW **<200A**	0.25% retail sales	$ 78.00	Art-1
		20kW-100kW **>200A**		$ 103.20	
		100kW < 1MW		$ 181.20	
We Energies	CER***	< 20kW		$ -	CGS 2
	CER	20kW-100kW	25 Customers	$ -	Wind
WPL	CER***	< 20kW		$ -	PgS-3
	$0.12 on-peak	20kW-200kW	0.5% retail sales	$ 152.42	Pgs-ART
	$0.074 off-peak	200kW-2MW		$ 304.85	
WPSC	CER***	< 20kW		$ -	PG-4

*CC/year is the additional Customer Charge per year
**CER - Customer's energy rate
***These are not ARTs, but are existing net metering tariffs which allow the customer to be a net generator

<u>Wind Experimental ART Takeaways</u>

- Each utilities wind tariff has unique characteristics
- For wind turbines smaller than 20kW each utility (except for DPC) offers a net metering schedule, rather than an ART, which pays customer energy rate for energy in excess of use
- Rates are likely too low to attract any participation, even with all available incentives

4.3 Conclusions – Do WI Experimental ARTs Meet Stakeholder goals?

Section 3.4 establishes the general goals which stakeholders have for ARTs in Wisconsin. This review of experimental ARTs shows that somewhat due to their experimental nature, these ARTs do not meet the policy goals established by stakeholders. These are some of the key issues:

- **Energy payment level is too low**, grants are necessary in combination with
- ART schedules are **not consistent** or easy to understand
- **Costs** of solar tariffs are **recovered** primarily **through green pricing programs**, rather than the all ratepayers
- **Costs** are **not distributed** among utilities
- **Terms are short** (10 years) & **price is not inflation adjusted**
- **Program cap** may be **too low** to achieve maximal benefits

Policy makers have already learned much from the information provided by utilities for the PSCW ART survey. Future experimental ARTs should be designed specifically to address stakeholder concerns. The PSCW can then design a comprehensive policy for Wisconsin based off lessons learned.

5. Technology Specific Energy Payment Levels for Wisconsin

5.1 Goal of Energy Payments

In our analysis, price levels were set to provide an internal rate of return (IRR) of 12.5% (similar to utilities). We simulated different scenarios in terms of price structure, contract length and specific characteristics of each technology, and obtained different price levels for each combination of factors.

5.2 Financial Assumptions

Our scenarios had some general financial assumptions: (1.) an annual inflation rate of 3%; (2.) a debt interest rate of 8%; (3.) 20% of capital costs are paid in cash and the remaining 80% with loans and noncompetitive federal incentives; and (4.) after the ART contract term ends avoided cost (≈$0.06/kWh) is paid to the RPP. Other assumptions were case-specific to the technologies, and will be described in each technology section.

5.3 Energy Payment levels for Each Technology

Energy payments and contract lengths given our financial assumptions were evaluated using the RETScreen International® software from Natural Resources Canada.

5.3.1 Biogas

I. *Introduction*

Biogas is produced by the fermentation of organic matter in the absence of oxygen, and its utilization is a way to recover energy from waste streams with high water content. In Wisconsin, a major source of wet organic waste is dairy manure. Manure produced by cows confined in stalls and barns can be collected and anaerobically fermented to generate biogas. Anaerobic digestion relies on microbes to convert organic materials present in manure into methane, carbon dioxide, other compounds (e.g. hydrogen sulfide and hydrogen gas) in trace amounts, and stabilized organic matter. As a fuel, biogas composed of 60-65% methane can yield about 540-650 BTU/ft^3. Biogas captured in dairy farms can either be cleaned and injected into natural gas pipelines or burned on site in a combustion device such as a flare, boiler, or generator. In order to generate electricity, biogas can be fed directly into a gas-fired combustion turbine. Combustion of biogas in an engine or microturbine converts the energy stored in the bonds of methane molecules into mechanical energy as it spins a turbine that produces electricity. In addition, waste heat from the engines can provide heat for use on farm.

a) Important Technology Characteristics

Anaerobic digesters can be beneficial to farms that have confined herds and hence big volumes of liquid manure to deal with. Anaerobic digesters will help to improve nutrient and manure management, reduce odor, and decrease the population of weed seeds and pathogens in the manure. Another benefit of utilizing manure to generate energy is the reduction in greenhouse gas (GHG) emissions. Because energy generation from manure implies the combustion of methane, there is a reduction in the amount of methane that would otherwise have been emitted from liquid manure stored in lagoons, for instance. The utilization of anaerobic digesters does not reduce GHG emissions from dry manure or manure directly applied to pasture or crops. Anaerobic digester system cost reduces substantially with economies of scale; therefore, larger biodigesters can typically produce electricity at a lower price.

b) Capacity

i. <u>Installed Capacity</u>

In Wisconsin, there are 22 anaerobic digesters at 17 dairy farms, with an installed capacity of 7.3MWe. These biodigesters process manure and produce heat and electricity (Kramer, 2008).

ii. <u>Potential Capacity</u>

Alliant Energy estimated there is 39 MWe of potential capacity in WI if biogas from dairy herds greater than 500 cows is utilized. Farms can also add high energy content substrates such as food waste in the digester systems to increase energy production, although this practice requires more careful monitoring of microbial environment and activity in the digester. We assessed scenarios for herds with 500 or more cows which exclusively utilize manure in the digesters.

II. *Assumptions*

A summary of the assumptions for our biodigester scenarios is in Table I.1, in the Appendix I.

a) Operation Assumptions

i. <u>Type of system</u>

We assumed the liquid phase Plug-Flow type of digester due to its good efficiency at digesting the solids content of scrapped ruminant manures (11-13%) and hence its high suitability to dairy systems in Wisconsin. Plug-Flow digesters also have a high rate of reaction and relatively short retention time (20-30 days), while mixed tanks work better with lower (less than 4-8%) solid contents (Lazarus, 2007; RIRDC, 2008). We assumed that the project has an active life of 20 years.

ii. Capacity Factor

We assumed a capacity factor of 90% for the generator, which is in the high end of the range of the capacity factor for operating engine-generator sets in the US: 80-95% (Alliant Energy, 2005 and GHD Inc. personal communication, 2009).

iii. Operating & Maintenance Costs

We assumed O&M costs of $0.02/kWh for 100 kW systems or 500 head herds, $0.0175/kWh for 150 kW systems or 750 head herds, and $0.0150 for 200 kW systems or 1,000 head herds (Alliant Energy, 2005).

iv. Other Income

One of the products of the anaerobic process is the stabilized organic material which manure is transformed into. This material can be used as bedding for cows. We accounted for an income due to bedding recovery of 1.5t/cow/year, valued at $20/t (Kramer, 2008).

b) Cost Assumptions

i. Incentives

We included the Renewable Energy Production Incentive (REPI) Federal grant as an income of $0.021/kWh generated for 10 years, and assumed tax exemption from the Renewable Energy Sales Tax Exemptions incentive that will be effective in WI as of July 1st, 2009 (DSIRE).

ii. Capital Costs

We used capital cost data for 16 operating plug-flow digesters based on quotes for systems between 2005 and 2008 (AgSTAR, 2009). The capital cost assumed in this study was $977,316 for herds with 500 cows, $1,120,670 for herds with 750 cows and $1,264,024 for herds with 1000 cows. The capital cost includes the digester, engine-generator set, engineering design, installation, post-digestion solids separation system and hydrogen sulfide treatment costs. These capital costs will be referred as "level A". Because capital costs can vary a lot and highly influence the feasibility of the projects, we also did comparison calculations including data from another study (Lazarus, 2007), which will be referred as capital costs "level B": $846,128 for herds with 500 cows, $1,095,263 for herds with 750 cows and $1,315,351 for herds with 1000 cows. Data of capital costs "level B" are illustrated in Figure 1 in Appendix I.

III. *Conclusion*

a) Energy Payments

i. Energy Payment Scenarios

Using previously mentioned assumptions, we calculated the IRR provided by the Experimental ARTs currently in place in WI for three herd sizes (500, 750 and 1000 cows) and two levels of capital costs (A and B). The IRR provided to RPPs by each of these energy payments is shown in Table 5.

Data in Table 5 shows that, for the assumed scenarios, the experimental ARTs in place in WI seem to provide financial feasibility to anaerobic digesters in farms with more than 750 cows, while smaller farms would probably have negative financial balance with those levels of energy payments. It is not likely that farms with less than 750 cows will install anaerobic digesters because the energy payments for existing tariffs don't even pay for the energy generation costs, as seems to be the case.

In order to evaluate which energy payments would provide RPPs with an attractive return on their investment, we simulated other scenarios with two types of energy payments (fixed and inflation adjusted

Table 5: Estimated plug-flow anaerobic digester IRR for varied herd sizes (and system capacities) and capital costs levels (A and B).

Herd Size (number of cows)	Project Size (kW)	Capital Cost ($/kW)	**Internal Rate of Return (%)** Experimental ART Energy Payments Fixed, for 10 years, by different utilities:			
			NSPW $0.073/kWh	DPC $0.07542/kWh	WEPCO $0.0883/kWh	WPL $0.0982/kWh
500	100	A: 9,773	*-9.2*	*-8.9*	*-7.2*	*-5.6*
		B: 8,461	*-4.8*	*-4.4*	*-1.5*	1.5
750	150	A: 7,471	1.8	2.5	7.4	12.4
		B: 7,302	2.8	3.6	8.9	14.2
1000	200	A: 6,320	12.7	13.9	21.7	28.3
		B: 6,577	10.3	11.4	18.6	24.9

for 2.5% rate of inflation) and three term lengths (10, 15 and 20 years). Energy payments which provide 12.5% IRR to RPPs for several scenarios are shown in Table 6.

Table 6: Anaerobic digester energy payments which provide 12.5% IRR for several scenarios

Herd Size (number of cows)	Project Size (kW)	Capital Cost ($/kW)	**Energy Payments ($/kWh)**					
			Fixed			Inflation adjusted (2.5%)		
			10 yrs	15 yrs	20 yrs	10 yrs	15 yrs	20 yrs
500	100	A: 9,773	0.146	0.132	0.126	0.123	0.111	0.105
		B: 8,461	0.121	0.111	0.107	0.101	0.093	0.089
750	150	A: 7,471	0.098	0.092	0.089	0.081	0.077	0.075
		B: 7,302	0.095	0.089	0.087	0.078	0.074	0.073
1000	200	A: 6,320	0.073	0.071	0.070	0.060	0.060	0.060
		B: 6,577	0.078	0.075	0.073	0.072	0.072	0.071

The payback time of projects receiving the energy payments estimated to provide 12.5% IRR were calculated for the capital costs “level A” scenario, ($9,773/kW and $6,320/kW for 500 and 1000 cows, respectively), for both fixed and inflation adjusted payments, and term lengths of 10, 15 and 20 years. The simple and equity payback times for these scenarios are shown in Table 7.

Cumulative cash flows for capital costs “level A” scenario ($9,773/kW and $6,320/kW for 500 and 1000 cows, respectively), fixed energy payments of $0.126/kWh and $0.070/kWh (for 500 and 1000 cows, respectively) during 20 years are graphically illustrated in Figure 2 and Figure 3 in Appendix I.

Table 7: Simple and Equity Payback Times for plug-flow anaerobic digesters with capital costs “level A”, according to herd and system sizes, type of energy payment, and term length. In years.

Herd Size	Project Size	Capital Cost “Level A”	**Payback Times (years)**					
		Energy payment	Fixed			Inflation adjusted (2.5%)		
		Term length	10 yrs	15 yrs	20 yrs	10 yrs	15 yrs	20 yrs
500 cows	100 kW	$/kWh	0.146	0.132	0.126	0.123	0.111	0.105
		Simple payback time	7.5	8.2	8.5	8.7	9.5	9.9
		Equity payback time	5.0	7.0	8.4	6.4	8.6	10.1
1000 cows	200 kW	$/kWh	0.073	0.071	0.070	0.060	0.060	0.060
		Simple payback time	8.2	8.4	8.5	9.4	9.4	9.4
		Equity payback time	6.9	7.5	7.9	8.7	8.7	8.7

The projects would have simple payback times ranging from 7.5 to 9.9 years and equity payback times from 5.0 to 10.1 years. These payback times might be seen too long to farmers considering installing anaerobic digesters. However the tariffs do offer low level of risk and a reasonable income stream, which may be sufficient encourage many farmers to invest in anaerobic digesters.

ii. Examples of Energy Payments for WI ART

For our analysis of ARTs we chose a tariff length of 20 years and fixed energy payment levels (not inflation adjusted), shown below in Table 8.

Table 8: Biodigester fixed price 20 year term ART energy payments

Herd Size (number of cows)	Project Size (kW)	Energy Payment fixed for 20 years ($/kWh)
Less than 1000	Less than 200	0.126
1000 or more	200 or more	0.070

For comparison purposes, we also simulated scenarios with complete-mix digesters, considering capital costs of $674,620 for herds with 500 cows, $831,214 for herds with 750 cows, and $987,809 for herds with 1000 cows, based on AgSTAR's study (2009). In addition, we assessed other scenarios using different debt interest rates (4% and 6.75%) and debt ratios (25% and 80%). These other scenarios and respective energy payments are illustrated in Table I.2 in the Appendix section.

b) Social and Economic Benefits

Anaerobic digestion of manure provides many benefits. Odor reduction provides increased options of when and where to spread effluents, maximizing nutrient usage and reducing the need for imported fertilizers. Spreading effluents in warm seasons can help optimize nutrient uptake, decrease risks of soil compaction and prevent runoff and water contamination. Anaerobic digestion also decreases the solids content of effluents. The reduction of solids contents reduces plugging and power requirements, and allows for utilization of highly efficient irrigation systems. In addition, the negative consequences of accidental contamination with anaerobically digested effluent are less severe than with raw manure, due to its lower biological oxygen demand (Wright, 2001).

A broad social benefit from utilizing biogas from dairy manure to generate energy is the reduction of GHG emissions. The combustion of biogas from anaerobic digesters reduces the amount of GHG that could otherwise be released to the atmosphere. The estimated amount of methane that could be emitted from stored liquid manure in a lagoon varies according to the diet of the cows, the manure management in the barns and stalls, the storage conditions in the lagoon, and the temperature. The combustion of biogas to generate electricity can prevent 48 ft^3 of methane from being released to the atmosphere per dairy cow per day (Vries, 2007), which is the equivalent of 7.07 metric tons of CO2 equivalent per cow per year (comparable to IPCC, 2006). The use of dairy manure in anaerobic digesters to generate electricity can therefore reduce 9.9 pounds of carbon dioxide equivalents per kilowatt-hour generated, according to our previously mentioned assumptions.

5.3.2 Biomass

I. *Introduction*

Combined heat and power (CHP) systems can efficiently produce both heat and electricity from wood residues, agriculture crops, and municipal waste. Small CHP systems under ART can be a major contributor to Wisconsin's renewable portfolio because it is a proven technology and there is a vast biomass resource in Wisconsin. In this study, small (≤ 15MWe) steam turbine CHP systems supplied from wood residues as fuel were evaluated. This analysis also includes retrofitting existing small coal plants in Wisconsin to CHP systems.

a) Important Technology Characteristics

CHP systems first burns solid biomass in a boiler to produce heat. This heat produces steam to generate electricity via the back pressure steam turbine. The excess 'useful heat' can be used to heat buildings or water. Two different sizes were considered in this study because biomass systems are highly sensitive to economies of scale. This is mainly because of efficiency differences between different plant sizes. Very small CHP systems (< 1MWe) generally use fire tube boilers and simple steam turbine cycles that produce low pressures and temperatures, which give efficiencies of 8-12% (Loo, 2008). Larger CHP systems over 1MWe use water tube boilers and more complex steam turbine cycles that can produce higher pressures and temperatures, which give efficiencies of 20-25% (Loo, 2008). Both capital and O&M costs are expensive and also highly sensitive to economies of economies. The capital cost per kWh is higher for smaller biomass systems because boilers and steam turbines are expensive regardless of its size. Similarly, the O&M cost per kWh is much higher for smaller biomass systems because experts need to maintain steam turbines and boilers regardless of its size.

b) Capacity

i. <u>Installed Capacity</u>

In 2007, 1.2% or 785GWh of Wisconsin's energy was generated from wood and wood derived biomass fuels (EIA, 2009). Additionally, there is 209MW installed capacity of small coal plants that could potentially be retrofitted into CHP systems (EIA, 2007).

ii. Potential Capacity

The total biomass potential capacity in Wisconsin is 3,525MW (Graham, 2007 and Milbrandt, 2005). However, only wood biomass will be considered in this study because it is currently the most commonly used biomass fuel. Biomass potential capacity from forest residues in Wisconsin is 358MW. In addition, there are 26 small coal plants of 209MWe installed capacity that can be retrofitted to biomass plants (EIA, 2007). Over half of these small coal plants are located near areas with vast amount of tree residue supply (ORNL, 1999). See Figure A.1 in Appendix for the locations of small coal plants in Wisconsin.

II. *Assumptions*

Size groups of < 1MWe CHP systems and systems between 1MWe and 15MWe CHP systems were considered in this analysis. Retrofitting small coal plants were also studied, where retrofitting implies that the coal plant boiler is completely replaced by a boiler and additional components required for the CHP system.

a) Cost Assumptions

i. Incentives

The Renewable Electricity Production Tax Credit federal grant, which pays $0.021/kWh of electricity generated from biomass for 10 years, was assumed in this study (DSIRE). Sales Tax Exemption incentive that will be effective in WI as of July 1st, 2009 was also assumed (DSIRE).

ii. Capital Costs

Table 9 represents the total and retrofitting capital costs for a 500, 5,600, and 8,400kWe system. Total capital cost depends on the biomass prep-yard, boiler, and back pressure steam turbine. One can observe that the capital cost per kWe is much higher for the 500kWe CHP system compared to systems over 5,000kWe.

Table 9: Total Capital and Retrofitting Cost (*US EPA 2007)*

	500kWe	5,600kWe	8,400kWe
Total Capital Cost [$/kWe]	9,261	4,630	4,001
Retrofitting Cost [$/kWe]	2,390	1,425	1,285

iii. Operating & Maintenance Costs

Table 10 represents the O&M costs for a 500, 5,600, and 8,400kWe system. The O&M cost depends on the prep-yard, boiler, and back pressure steam turbine. Similar to the capital cost, one can observe that the O&M cost per kWe is much higher for the 500kWe CHP systems compared to systems over 5,000kWe.

Table 10: Total O&M Cost (*US EPA 2007)*

	500kWe	**5,600kWe**	**8,400kWe**
Total O&M Cost [$/kWe-yr]	1,150	284	202

iv. Fuel Costs

The nominal biomass fuel cost was assumed at $20/ton based on 45% moisture content (Martin, 2008)

v. Other Income

CHP systems allow the RPP to sell heat in addition to power. In the base case scenario, it was assumed that the 50% of the usable heat generated from CHP systems can be sold at $6/MMBTU in the base case scenario (IEA, 2007). $6/MMBTU was assumes as the base price of natural gas.

b) Operation Assumptions

i. Capacity Factor

Capacity factor can range from 70% to 95%, allowing biomass combustion systems to be baseload candidates that can potentially replace coal plants. 85% was assumed in this study.

ii. Efficiencies

Table 11 summarizes the steam turbine (electrical) and heat efficiencies. See Appendix for method of calculation.

Table 11: Electrical and Heat Efficiencies *(Loo, 2008)*

	500kWe	**8400kWe**
Electrical Efficiency	12%	24%
Heat Efficiency	70%	45%

III. *Conclusion*

a) Energy Payments

i. Energy Payment Scenarios

Figure 7 shows energy payment scenarios for a 500kWe and an 8,400kWe CHP system assuming a 12.5% expected IRR for the RPPs. “Base case” represents the base case scenario assumed in this study. “Income tax” represents a 35% income tax imposed to the RPP. “Inflation Adj.” represents an inflation adjusted credit rate at 2.5% annually. The smaller 500kWe CHP system benefitted greatly from the inflation adjustment because it mitigated their high O&M cost per kWh. “No heat” represents no heat being sold from the CHP systems. “Retrofit” represents the CHP systems being retrofitted from small coal plants. Retrofitting both 500kWe and 8,400kWe systems were much more economical than building new CHP systems. Finally, “10 yr credit” represents a credit length of 10 years instead of 20 years.

There are three major take away in this study. First, inflation adjusted ART may be necessary for very small CHP systems with high O&M cost per kWe. Second, a long term ART of at least 20 years should be imposed. Third, the retrofitting coal plants in areas near wood residues can be very economical compared to new biomass CHP systems. In addition, this would create additional local jobs within the State without having to import out-of-state coal.

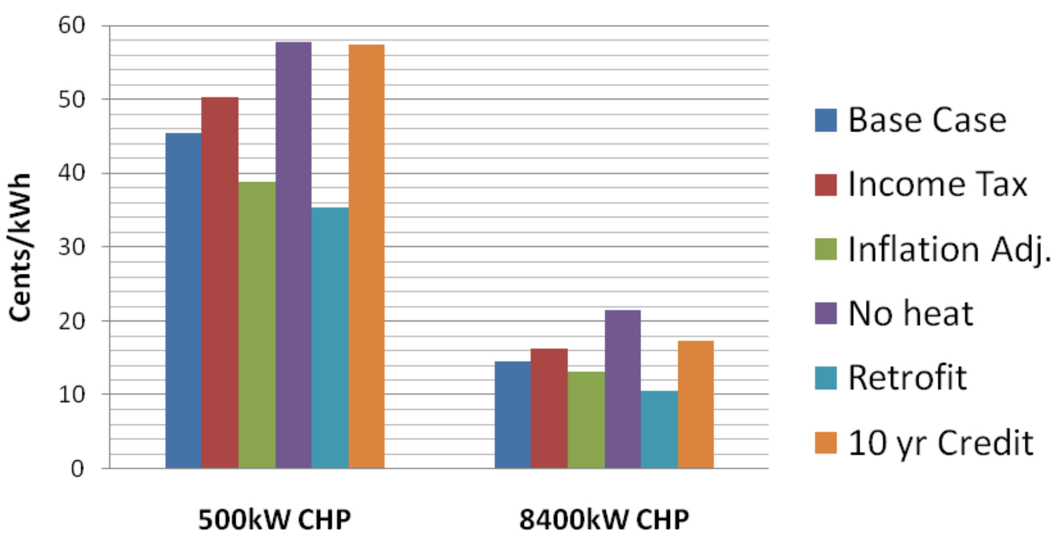

Figure 7: Energy Payment Scenarios for a 500kWe and a 8,400kWe System

ii. Energy Payments Scenario Chosen for Example WI ART

Table 12 represents the rate and term length of the energy payment for small CHP systems assuming the 12.5% expected IRR for the RPPs.

Table 12: Energy Payment Rate and Term Length of ART

Project Size	< 1MWe	1MWe – 15MWe
Term Length	20 yrs	20 yrs
$/kWh fixed*	**0.45**	**0.15**

b) Social and Economic Benefits

Generally, biomass CHP systems are capable of substituting coal plants due to their high capacity factor. Replacing small coal plants would reduce the amount of out-of-state coal and would require the labor to collect local wood residues and invest fuel dollars on homegrown energy. In addition, biomass plants are 1.5 to 3 times more labor intensive that coal plants (Lin, 1996). If a biomass CHP system can produce about 5 workers per MW, this would yield approximately $21,000/MW in State tax revenue that will stay inside Wisconsin (Morris, 1999).

5.3.3 Solar

I. *Introduction*

a) Important Technology Characteristics

While Wisconsin gets far less solar insolation than the U.S. Southwest, a more relevant comparison for the evaluation of ART policy design is Germany, which gets approximately 1100 kWh per square meter of solar insolation annually (European Commission). Similarly, Wisconsin receives between 1150 and 1100 kWh per square meter annually in most locations across the state (NREL Maps).

b) Capacity

i. Installed Capacity

Wisconsin reached an installed solar capacity of 1 MW in March, 2008 (Wolter, 2008). Capacity has grown substantially since then due to experimental tariffs in combination with Focus on Energy grants and federal financial incentives.

ii. Potential Capacity

The physical potential capacity for PV development, even if defined as narrowly as a fraction of south-facing roof space on existing buildings, is not the primary limiting factor on development.

II. *Assumptions*

a) Cost Assumptions

i. Incentives

As with each of the four ART-eligible technologies considered, we only included noncompetitive financial incentives from outside Wisconsin. One exception to this was that there will be no sales tax on solar electric systems starting June 2009 (www.dsire.org). We therefore did not include sales tax in our capital cost or ongoing cost models for any scenario. The largest non-ART financial incentive is the federal 30% tax credit for both individuals and business. For solar electric systems, the money can also be taken as a grant under the American Recovery and Reinvestment Act of 2009.

ii. Capital Costs

Instead of using empirical installed costs from Wisconsin exclusively, we used California 2006-2007 per kW installed costs for systems over the 10kW range. California numbers were used because they install the greatest number of systems, and one of our assumptions has been that with ART Wisconsin may gain some of the benefits of increased economies of scale. Average Wisconsin installed capital costs are over $8,000 per kW installed.

For systems under 10kW, an installed cost 2.5% lower than California was chosen. Using these conservative capital costs results in slightly lower energy payments for the corresponding ARTs and encourages only the most efficient solar electric projects to be funded.

In our models, the capital costs are bracketed based on system sizes. Note that this design may lead to inefficient allocation of resources because it may provide an incentive to slightly change the size of the system compared to what the RPP would otherwise have installed in order to get into the higher tariff energy payment bracket.

iii. <u>Operating & Maintenance Costs</u>

Compared with biopower systems, PV has extremely low operations and maintenance costs. We used 0.5% of the capital cost. This amount ensures coverage for inverter replacements every 10 years and assumes that the owner would perform periodic maintenance such as snow removal and cleaning.

iv. <u>Other Non-capital Costs: Insurance</u>

Insurance cost was assumed to be 0.4% of the capital cost. This was directly taken from examples with small wind generators (Sagrillo, 2000). To insure a renewable energy system as an appurtenant structure to a home or business building, the cost is $2.00-$3.50 per $1000 value. To this we added an estimate for liability insurance that it would be in the range of $10 to $40 per year. The combination of these, 0.4%, is $4 per $1000 capital cost for insurance.

b) Operation Assumptions

i. <u>Capacity Factor</u>

To simplify our calculations, we assumed that the amount of sun was approximately constant around the state. The RETscreen software scenarios we ran included location-specific variations in annual insolation, but they had a very small impact on the energy rate. RETscreen inputs had all solar panels facing directly south, with no shade, and at the optimal angle to maximize generation.

This resulted in a 16.3% capacity factor chosen for all systems, when using a panel which is 13.5% efficient, facing directly toward the equator, not shaded by any terrestrial structures, angled at 35^{o}, with a 90% efficient inverter. We consider this to be a conservatively high estimate for capacity factor.

ii. <u>No Shading – Implies Snow Removal</u>

Due to the 35 degree fixed tilt of the panels, snow removal is necessary to achieve 16% capacity factor.

III. *Conclusion*

a) Energy Payments

i. <u>Energy Payments Scenario Chosen for Example WI ART Tariff</u>

Even using the most optimistic assumptions, our results showed that for solar electric projects to earn a reasonable return energy payments would need to be approximately double the current experimental tariff buyback rates. These are displayed in Table 13 below.

Table 13: Mid-range Scenario Energy Payments to Provide Comparable Return by System Size

Solar Electric	\$0.53	< 10kW
	\$0.50	10 < 100kW
	\$0.48	100 < 500kW
	\$0.44	> 500kW

5.3.4 Wind

I. *Introduction*

Wisconsin's utility scale wind potential, given by the American Wind Energy Association (AWEA) as 6440MW average generation, is sufficient to provide Wisconsin with 90% of projected 2009 electric energy consumption. This potential projection, which originates from a 1991 U.S. Department of Energy of report that examines wind on a 1/3 by 1/4 degree grid of the US, argues that considering environmental and moderate land use exclusion 4.3% of Wisconsin's land area has the minimum necessary wind speed (>= Class 3, average wind speed > 6.4m/s at 50m) to be considered for utility scale wind farms (Elliot, 1991). The Wind Resource Maps of Wisconsin, one of which is shown in Figure 8 below, estimate Wisconsin's wind resource on a drastically more detailed 200m grid. These maps likewise show that a significant portion of Wisconsin has class 3 and above wind (although no more exact percentage of Wisconsin land area is given in the AWS TrueWind report).

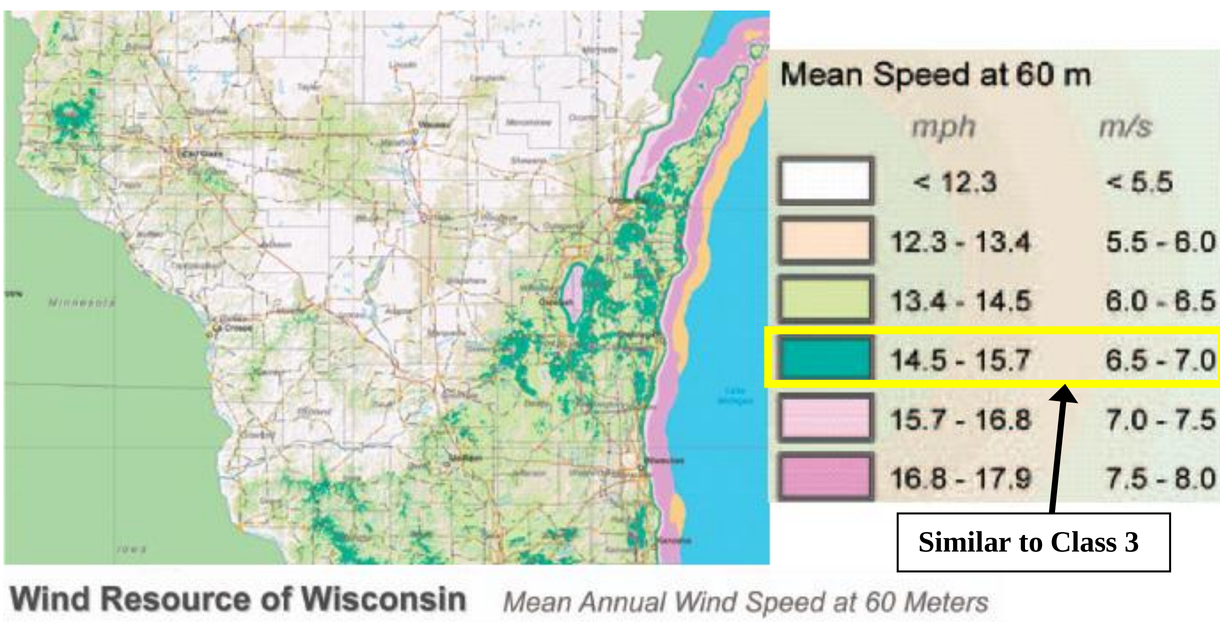

Figure 8: Wind Resource of Wisconsin, Mean Annual Wind Speed at 60m (AWS Truewind, 2007)

Since Wisconsin's class 3 wind resource is sufficient to provide a considerable portion of Wisconsin's energy, the tariff will be designed to provide only provide economic return (12.5% IRR on 20% equity) to wind turbines sited in these geographically preferential areas (dark green in Figure 8).

a) Important Technology Characteristics

Geographic Distribution:

The geographic distribution of Wisconsin's wind resource is currently most important from a transmission and wind farm siting perspective. Because Wisconsin's wind resource is not evenly distributed among utilities though, the enactment of a uniform wind tariff for Wisconsin will disproportionately impact utilities with a wind resource. The geographic distribution of wind presents many tariff design opportunities which should be considered:

i. Should the wind ART program cap be distributed among utilities to represent individual utility's wind resource?
ii. Should the costs of the wind tariff be distributed among utilities?
iii. If the costs of the wind tariff are distributed among utilities, how are the renewable energy credits distributed?
iv. Do the geographic characteristics of wind necessitate that wind is treated differently than other technologies being considered for the ART?

Impact of Size Class on Certainty of Analysis:

Wind is generally split between two categories: small wind (less than 100kW turbine rating) and utility scale wind installations (100kW to 5MW turbine rating). These two categories differ most notably in market size with 17.4 MW of small wind and 8,558 MW of utility scale wind installed in the US in 2008 (LBNL, 2009; AWEA[a], 2009). The characteristics of utility scale wind farms including capacity factor, $/kW installed cost, and power sales prices are comprehensively tracked by the Annual Report on US Wind Energy Markets (LBNL, 2009). The market size for small wind is comparatively small and as a result similar performance and cost data is simply not available. The AWEA does indicate though that small wind turbine costs vary widely, generally in the range of $3-$6/watt (AWEA[a], 2009) and Renew Wisconsin has provided the average 2008 installed costs of Focus on Energy small wind installations.

Turbine Characteristics – Swept Area and Generator Rating:

A wind turbine can be considered to have two have two generators – the rotating blades which transform wind energy to rotary mechanical motion and the electrical generator which transforms the rotary mechanical motion to electrical energy. Betz's law shows that a maximum of 59.3% of wind's energy can be captured with a turbine. The amount of energy captured by a wind turbine is therefore primarily a function of the area of the rotating blades, electrical generator power rating, and the efficiency at which the rotating blades transform wind energy to rotary mechanical energy. Turbines designed to operate at a high capacity factor in low wind speed will typically have a smaller electrical generator rating for a given turbine swept area, while turbines designed for higher wind speeds will typically have a larger generator rating per swept area. Figure 1 below clearly shows that wind turbine capacity factor for a given wind speed is a function of the ratio of turbine swept area to electrical generator rating.

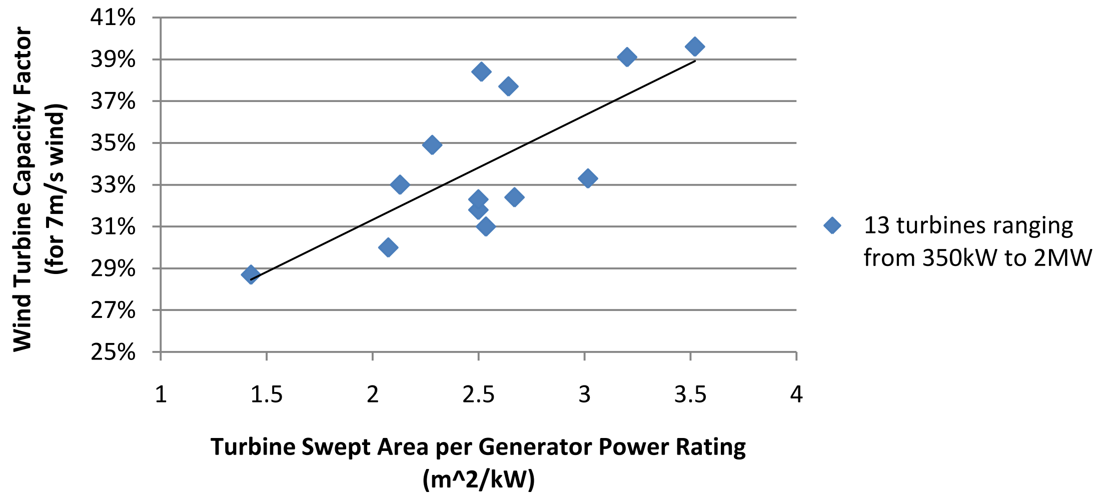

Figure 9: Capacity factor versus turbine swept area per generator power rating for 7m/s wind resource (see Table 19 and Table 20 for source data).

b) Capacity

i. Installed Capacity

There is currently 448.9MW of installed utility scale wind capacity in WI (AWEA[b], 2009), and Renew Wisconsin indicates there are an additional 1338MW of proposed projects (Vickerman[b], 2009). Existing Wisconsin small wind capacity numbers are not publicly available, but are likely in the range of a MW or less.

ii. Potential Capacity

Figure 8 shows that a substantial portion of Wisconsin has a wind resource similar to class 3. The Wisconsin Wind Resource Study which this map is taken from does not indicate what percentage of Wisconsin's land is class 3 and above. A conservative assumption, judging by this map and prior studies, is that accounting for land use restrictions 2% of Wisconsin's land area may have class 3 wind and be available for wind farm development. Supposing this area is developed at a turbine density similar to the

Blue Sky Green Fields wind farm, there is potential for about 11,500MW of installed capacity.[4] Considering that this installed capacity could generate about 43% of Wisconsin's annual electricity[5] and that this level of wind penetration is currently technically infeasible, Wisconsin's wind potential is unlikely to be saturated in the near future. Due to this apparent abundance of potential capacity, it is unlikely there will be substantial competition between customer generators and utilities for windy sites in the near future.

II. *Assumptions*

a) Cost Assumptions

i. Incentives

As with each technology being analyzed for the ART, only noncompetitive incentives are considered. The only state incentive considered is the sales tax exemption for wind provided by Wisconsin Statute § 77.54(56). Wind systems less than 100kW are assumed to receive either the Federal Business Energy Investment Tax Credit or the Residential Renewable Energy Tax Credit. Both incentives provide a credit equivalent to 30% of the system cost. Systems greater than 100kW are assumed to receive the Federal Production Tax Credit of $0.021/kWh (www.dsire.com).

ii. Capital Costs

Capital costs consist primarily of the cost of a site assessment, site specific engineering design work, the wind turbine, tower, power converter, and electrical connection to the grid, and the labor and other raw materials for installation. For our assessment we have simplified the capital costs to one lump $/kW installed cost for each size category. Small wind is divided into two categories, <20kW and 20kW-100kW, and utility scale wind is divided into two categories as well, 100kW-1MW and 1MW-15MW. These size categories reflect both divisions in incentives (<20kW eligible for net metering, <100kW eligible for 30% tax credit, >100kW eligible instead for production tax credit) and technical divisions in turbine design (<20kW typically simple and easy to maintain, 20kW-100kW more complex with high

[4] Blue Sky Green Fields covers 10,600 acres and has 145MW installed capacity (WE Energies, 2009). 2% of Wisconsin land area is 838,374 acres. 145MW x (834,374 acres / 10,600 acres) = 11413MW

[5] 11,500MW x 30% Capacity Factor x 8766 hours/year = 30.2 million MWh. Wisconsin's approximate annual electric consumption = 70 million MWh. 30.2 million MWh / 70 million MWh = 43%.

variance in design type and cost, >100kW consistent design across manufacturers and highly skilled maintenance and 3 phase electrical connection – possibly transmission level - necessary).

It is challenging to establish representative, average installed costs for these different classes of wind generators. The exponential growth of utility scale wind farms has helped to better establish normative installed prices for these large scale systems, but the market for small scale wind systems has not experienced this same level of growth. The following table outlines the average installed $/kW costs used for this study and section III.a) explores the sensitivity of the profitability of wind installations to capital costs.

Table 14: Average Installed Cost per kW for Wind

Size Class	Installed Cost Per kW	Justification
<20kW	$6,500	The cost was chosen to be slightly lower than the $6775/kW average cost of 2008 Focus on Energy installations sited by Renew WI in their reply to the PSC ART Survey (Renew, 2009)
20kW – 100kW	$4,000	The cost was chosen to be similar to the estimated installed cost for two turbines in this size category, the Northern Wind Power NW100 100kW turbine and the Entegrity 50kW turbine.
100kW-1MW	$2,800	A slightly lower cost than that provided by Renew in their PSC survey response was used (Renew, 2009). This cost, which is 24% higher than for 1MW-15MW turbines, seems within reason but may be too high.
1MW-15MW	$2,300	The 2008 average installed costs of wind farms in the US ranged from about $1400 to $2600 per kW, with an average cost of about $1950/kW (Berkely, 2009). The average size of these wind farms was 82MW. Because the tariff will promote smaller and therefore likely more expensive projects an installed cost near the upper end of the distribution, $2300/kW, was chosen.

iii. Recurring Costs - Operating & Maintenance and Insurance Costs

For systems <100kW operating and maintenance is assumed to be 1% of capital cost. For systems >100kW operating and maintenance is assumed to be $15/MWh. Insurance for systems less than 100kW is assumed to cost 0.4% of installed cost per year[6] and for systems >100kW no additional insurance costs are incorporated for simplicity. Paul Gipe argues higher recurring costs, in the range of 4%, are more representative of the other costs encountered by customer generators, for example land use

[6] Assumes that system owners can purchase liability and property insurance for $40 per $1000 of property value, based off insurance advice from Mick Sagrillo posted on AWEA website(Sagrillo, 2009)

opportunity cost and end of life removal (Gipe, 2009). Our analysis assumes that some customers will either have lower recurring costs or value their recurring costs less and has therefore chosen the lower recurring cost numbers to be sufficient. However, in the case that the ART is not successful in gaining participation it may be necessary to have ART prices reflect higher, more comprehensive recurring expenses.

b) Operation Assumptions

i. Capacity Factor

The amount of energy generated by a wind turbine (capacity factor describes this as a ratio) is primarily a function of the wind speed at the turbine's hub height and the mechanical design of the wind turbine. The efficiency of the grid-tied power converter paired with the turbine will also impact capacity factor, but since most turbines are sold with a power converter and their energy production ratings reflect this, the impact of power converter efficiency will not be further considered. A representative capacity factor for each wind turbine size class will be determined by first establishing average wind speed at the average hub height and then by estimating the energy production for a representative set of wind turbines.

Average Wind Speed – Adjusted for Average Turbine Height:

Wind speed is a function of height above the ground and must therefore be adjusted to accurately reflect the average hub height for each turbine class. Table 15 below shows the class 3 wind speed adjusted for different heights using the $1/7^{th}$ rule[7]. Table 15 also shows that the power density of wind is a function of height^3, so for every 10% increase in wind speed wind power density increases by 33%. For a given wind turbine there exists an optimum balance between tower height (and therefore tower cost) and the resultant energy generated. Real wind turbine towers are only available in discrete heights though, so a tower height and corresponding wind speed for that height will be chosen for each size class. Turbines <100kW are generally available with a maximum tower height of about 40m, therefore 40m hub height

[7] The $1/7^{th}$ rule is a commonly used approximation for extrapolating wind speed to different heights: $(WindSpeed_1 / WindSpeed_2) = (Height_1 / Height_2)$ ^(1/7).

will be used for the <20kW and 20kW-100kW size classes. Turbines >100kW are typically available with tower heights ranging from 60-100m. Many wind farms in Wisconsin have 60m towers for turbines <1MW and 80m towers for turbines >1MW so these tower heights will be used for our analysis. Table 16 shows the hub height and the corresponding tariff design wind speed which was chosen.

Table 15: Class 3 Wind Speeds Adjusted for Height

Wind Speed & Power Density	Height above ground 20m	40m	50m	60m	80m
min (m/s)	5.6	6.2	6.4	6.6	6.8
max (m/s)	6.1	6.8	7.0	7.2	7.5
min (W/m^3)	201	273	300	329	360
max (W/m^3)	265	367	400	435	492

Table 16: Tariff Design Turbine Hub Height and Corresponding Wind Speed

Size Class	Turbine Hub Height	Tariff Design Wind Speed
<20kW	40m	6.0 m/s
20kW-100kW	40m	6.0 m/s
100kW-1MW	60m	6.75 m/s
1MW-15MW	80m	7.0 m/s

Turbine Capacity Factor for <100kW Size Classes:

Datasheets for wind turbines rated at less than 100kW almost always contain estimates of annually energy produced for a given wind speed. Eleven wind turbines listed as approved for Wisconsin Focus on Energy grants are analyzed in this section to determined an average capacity factor for turbines <100kW. Table 17 shows that for turbines <20kW it is relatively straightforward to estimate the average capacity factor, the average capacity factor is simply 30% for the chosen 6.0m/s average wind speed.

Table 17: Capacity Factors for <20kW Wind Turbines in 6m/s Average Wind Speed

Manufacturer	Swept Area	Generator (kW)	Swept Area Per kW	Cap Factor 6.0 m/s
Skystream	10.9m^2	2.4kW	4.54m^2/kW	25.7%
ARE 110	10.1m^2	2.5kW	4.04m^2/kW	29.2%
Whisper	15.9m^2	3kW	5.3m^2/kW	31.0%
Endurance	23.5m^2	5kW	4.7m^2/kW	32.0%
ARE 442	41m^2	10kW	4.1m^2/kW	31.0%
			Average	**30%**

Table 18 though shows a much more complex picture for turbines ranging from 20-100kW - capacity factor varies widely, from 25.7% up to 52.5%. The key difference among these turbines is the ratio of turbine swept area to generator power rating. The lower capacity factor turbines, the Entegrity and Northwinds models, have a swept area per kW rating of about 3.5 m^2/kW, while the higher capacity factor turbines have much higher swept area per kW rating ranging from 5.8-8.28m^2/kW. It is assumed for our analysis that the turbines with the higher swept area per kW cost substantially more than the Entegrity and Northwinds models, so an average capacity factor weighted towards these two turbines, 30%, is chosen for the analysis.

Table 18: Capacity Factors for 20kW-100kW Wind Turbines in 6m/s Average Wind Speed

Manufacturer	Swept Area	Generator (kW)	Swept Area per kW	Cap Factor 6.0 m/s	Installed Cost
Entegrity	177m^2	50kW	3.54 m^2/kW	27.2%	In the range of $4000/kW
Northwinds	346m^2	100kW	3.46 m^2/kW	25.7%	
Endurance	290m^2	35kW	8.28 m^2/kW	41.0%	Since rotor is almost the same size as Northwinds rotor, cost assumed to be substantially greater than $4000/kW
Energie	290m^2	35kW	8.28 m^2/kW	52.5%	
Endurance	290m^2	50kW	5.8 m^2/kW	39.0%	
Energie	290m^2	50kW	5.8 m^2/kW	45.4%	
			Average	**38%**	

Turbine Capacity Factor for >100kW Size Classes:

Turbines rated greater than 100kW typically only provide a power versus wind speed curve so capacity factor was estimated with RETScreen. The simplest case was assumed – Raleigh distribution of wind speeds, 100% in service time, and no additional electrical losses. Table 19 shows that for wind turbines rated between 100kW and 1MW the average capacity factor for 6.75m/s average wind speed is in the range of 30%.

Table 19: Capacity Factors for 100kW-1MW Wind Turbines in 6.5 & 7.0 m/s Average Wind Speed

Manufacturer	Diameter (meter)	Generator (kW)	Cap Factor 6.5 m/s	Cap Factor 7.0m/s
Suzlon	33m	350kW	24.6%	28.7%
Siemens	44m	600kW	26.0%	31.0%
Vestas	47m	650kW	27.9%	32.4%
Repower	48m	600kW	28.8%	33.3%
Enercon	48m	850kW	28.5%	33.0%
Vestas	52m	850kW	27.5%	31.8%
Gamesa	52m	850kW	27.9%	32.3%
		Average	**27.3%**	**31.8%**

Table 19 below shows that for turbines >1MW operating with a 7.0m/s average wind speed at hub height capacity factor is an average of 34%. However to account for out of service time and additional losses, a slightly lower capacity factor of 33% is chosen for our analysis.

Table 20: Capacity Factors for >1MW Wind Turbines in 7.0 & 7.5 m/s Average Wind Speed

Manufacturer	Diameter (meter)	Generator (MW)	Cap Factor 7 m/s	Cap Factor 7.5m/s
WindTec	66m	1.5MW	30.70%	34.90%
Vestas	66m	1.65MW	26.10%	30%
Suzlon	82m	1.5MW	35.50%	39.60%
Vestas	82m	1.65MW	35.30%	39.10%
Vestas	80m	2MW	34.40%	38.40%
Repower	82m	2MW	33.40%	37.70%
		Average	**34%**	**38%**

Comparison of <100kW Wind Turbines to >100kW Wind Turbines:

Figure 1 below illustrates the primary difference between small wind and utility scale wind turbines - small wind turbines typically have a much higher ratio of turbine swept area per generator power rating. This largely explains why small wind turbines cost so much more per installed kW capacity, small wind turbines essentially require more turbine area to convert the same amount of energy as a large wind turbine. This can alternatively be thought of in terms of conversion efficiency, small wind turbines do not convert as much wind energy to mechanical energy as large wind turbines. Large wind turbines have higher conversion efficiency due primarily to the advantages of having variable blade pitch.

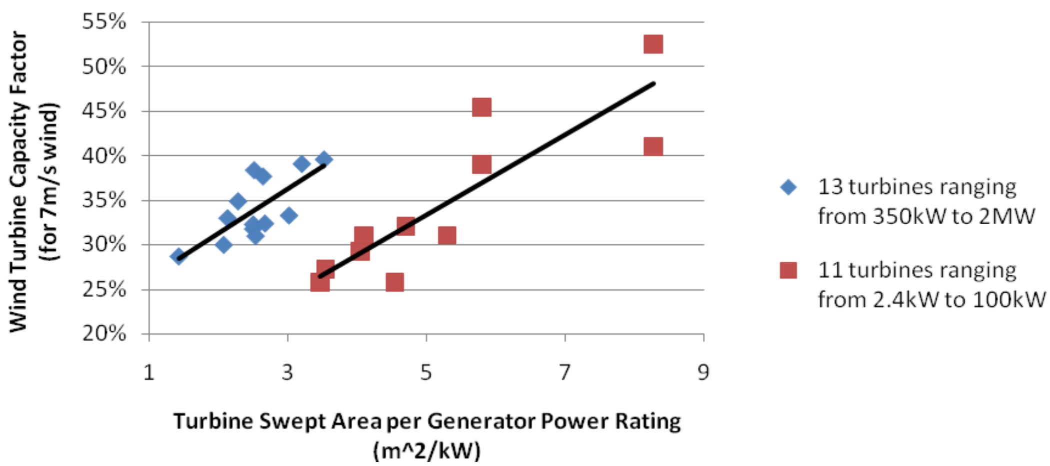

Figure 10: Comparison of Wind Turbine Capacity Factor to Swept Area per kW Rating for <100kW and >100kW wind turbines

III. *Conclusions*

a) Energy Payments

i. Energy Payment Scenarios

Tariff Prices were calculated using the assumption in part II for 10, 15, and 20 year tariffs, shown below in Table 21. Some of the other important assumptions that went into these tariff prices are:

- Tariff price provides 12.5% IRR on owners equity – for systems <100kW installed costs paid for with 30% incentive, 20% equity, and 50% debt at 8% interest rate; for systems >100kW installed costs paid for with 20% equity and 80% debt at 8% interest rate.
- Recurring costs (O&M) increase 3% per year
- System life assumed to be twenty years
- For the period when the tariff has expired but the system is still operating – systems <20kW receive net metering ($0.12/kWh) and systems >20kW receive avoided costs ($0.6/kWh)

Table 21: 10, 15, and 20 Year ART Prices for Wind Systems

Size Category	$/kW Installed	Cap Factor	Recurring Expenses	Incentive	Tariff Price ($/kWh) 10 Year	15 Year	20 Year
<20kW	$6,500.00	30%	1.4% of Capital Cost	30% Tax Credit	$0.293	$0.255	$0.232
10kW-100kW	$4,000.00	30%			$0.184	$0.158	$0.146
100kW-1MW	$2,800.00	30%	$15/MWh	$21/MWh PTC	$0.162	$0.138	$0.127
1MW-15MW	$2,300.00	33%			$0.108	$0.096	$0.089

Sensitivity of Payback to Capacity Factor and $/kW Installed Cost:

A substantial concern with ARTs is that renewable power producers (RPP) will earn an unfair profit. One method for analyzing how sensitive the ART prices are to errors in our input assumptions is to examine what internal rate of return an RPP will earn if rather than taking out a loan they pay all of the equity out of pocket (for systems <100kW 70% equity, >100kW 100% equity). Table 22 below shows that for 20kW-100kW systems the RPP will earn an IRR of 9.3% for the base case.

Table 22: Sensitivity of IRR to capacity factor and installed costs for 20kW-100kW systems, 20 year tariff

IRR	Cap Factor					
Cost/kW	48%	42%	**36%**	**30%**	**24%**	18%
$6,800.00	8.2%	5.90%	3.40%	0.60%	-2.90%	-8.00%
$5,400.00	12.4%	9.9%	7.2%	4.2%	0.7%	-3.9%
$4,700.00	15.3%	12.5%	9.6%	6.5%	2.9%	-1.6%
$4,000.00	18.9%	15.9%	12.7%	9.3%	5.5%	0.9%
$3,300.00	**23.9%**	20.4%	16.7%	12.9%	8.7%	3.9%
$2,600.00	31.3%	27.0%	22.6%	18.0%	13.2%	7.9%

If for example the RPP spends more money, $6800/kW, on a more efficient wind turbine, 48% capacity factor, the RPP will still only be able to earn 8.2% IRR. This table shows in general that RPPs will only be able to earn an excessive profit for cases that are far from the designed for base case. This table also gives insight into how an RPP may choose whether or not to invest in a system. For example, if an RPP has a source for a very affordable 4% loan, they may consider installing a less profitable system, for example a $4,000/kW 24% capacity factor system which would only earn a 5.5% IRR in this case.

Table 23 shows that for wind turbines >1MW, where installed costs and capacity factor are substantially more certain, that there is little opportunity for RPPs to earn excessive profits within reasonable installed cost/kW and capacity factor ranges.

Table 23: Sensitivity of IRR to capacity factor and installed costs for >1MW systems, 20 year tariff

IRR	Cap Factor				
Cost/kW	37%	**33%**	**29%**	**25%**	21%
$2,900.00	6.9%	5.3%	3.7%	1.9%	0.0%
$2,600.00	8.5%	6.8%	5.1%	3.2%	1.2%
$2,300.00	10.4%	8.6%	6.7%	4.7%	2.6%
$2,000.00	12.8%	10.9%	8.8%	6.6%	4.3%
$1,700.00	15.9%	13.7%	11.4%	9.0%	6.5%

ii. <u>Energy Payments Scenario Chosen for Example WI ART Tariff</u>

For our analysis we chose to use the 20 year tariff values due to their lower upfront cost and consistency with other ARTs.

5.4 Summary of Established Tariff Prices for Example Wisconsin ART

Figure 11 below summarizes the tariff energy payment levels, size categories, and contract lengths established in section 5.3.

WI ART Policy

Schedule **ART-WI**

Designed using stakeholder input

Energy Payments

•Energy payments designed to provide rate of return comparable to utilities allowed rate of return

	$/kWh	Project Size	Program Cap
Biomass	$0.430	< 5 MW	?.??% of retail sales
	$0.150	5MW < 15 MW	
Biodigester	$0.126	< 200 kW	
	$0.070	> 200kW	
Solar	$0.53	< 10kW	?.??% of retail sales
	$0.499	10 < 100kW	
	$0.47	100 < 500kW	
	$0.43	> 500kW	
Wind	$0.232	< 20kW	
	$0.146	20 < 100kW	
	$0.127	100kW < 1MW	
	$0.089	> 1MW	

Contract Lengths

Biomass	Biodigester	Solar	Wind
20 Years	20 Years	20 Years	20 Years

I. Participating Utilities

Preferably – **all utilities participate**, PSC jurisdiction is limited though

II. Cost Recovery

All citizens benefit from ART, so costs should be evenly distributed among ratepayers

III. Program Cap

Ideally designed to balance the benefits to WI residents w/ the cost of the program

IV. Inflation Adjustments

Critical for technologies with high O&M costs – Biogas & Biomass

V. Environmental Attribute Ownership

- Utilities retain renewable energy attributes
- Owners **may** have option to retain carbon credits - utilities do not currently need credits
- Owners retain other environmental attributes

Figure 11: Summary of Example WI ART Characteristics (energy payment levels, size classes, etc)

6. ART Scenario for Wisconsin: 3% of Retail Electric Sales Program Cap

In order to begin assessing the possible costs and benefits of ARTs for Wisconsin, we first considered a scenario with an overall program limit of three percent of annual generation. The total generation considered was the combined annual kWh of the five largest utilities in the state as entered into the PSCW comment record for the ART docket.

The total cost estimates developed here are not meant to advocate for or against a program cap or ceiling on the ART as a whole, but rather to establish a range of possible costs to utilities and electric ratepayers for the purpose of evaluating policy options.

The energy payments, capacity factors, and avoided generation costs used are comparable to, or derived directly from, those we calculated for each technology in this analysis. Bio-digester energy payments do not account for the value of all co-products to the renewable power producer and are therefore conservatively high. Electric generation figures from combustion of solid biomass are weighted heavily toward larger systems and include economic value to the heat produced. Underlying assumptions and methodology are described in more detail in the technology sections and appendices. Table 24 below displays the aggregated cost components.

Table 24: Aggregate cost components for WI ART scenario with 3% retail sales program cap

	Weighted Average Energy Payment ($/kWh)	Generation (kWh/year)	Average Capacity Factor	Imputed Capacity (MW)	Cost (Energy Payments net Avoided Costs)
PV	0.500	71,487,208	0.150	54	$30,024,627
Wind	0.120	71,487,208	0.318	41	$4,289,232
Digesters	0.100	315,360,000	0.900	40	$11,913,600
Biomass	0.180	1,257,364,863	0.850	169	$152,986,184
TOTAL					**$199,213,643**

To put this $199 million estimate into perspective, consider that the retail sales of electricity of the five largest investor-owned utilities are over $5.5 billion per year. In the event that all tariffs were to be fully subscribed and in operation, that all costs were added on to ratepayers' bills, and that there would be no offsetting financial gains whatsoever, $199 million would be a net increase in rates of four percent. This also assumes the unlikely event that the increased supply of electricity resulting from the requirement to purchase ART-generated renewable power would exhibit no compensating downward pressure on retail prices at all.

Costs of ART: One Percent Case

Under these scenarios, a fully subscribed ART would be paying for the development of hundreds of small renewable energy systems across the state. The energy payments that would be sufficient to provide an attractive rate of return would not be the same for every system, at every location, for all renewable power producers. If energy payments were set 25% lower, and a program cap of 1% was achieved with that level of incentive, the overall rate impact might be closer to 1% of the utility ratepayers' bills.

Quantifiable Benefits of ART: Market Price for Carbon Equivalent Allowances

Rate impacts of any ART program will be lower than the linear extrapolation of energy payments in the three percent case considered here, depending on how the ART policy treats the allocation of economic benefits. For example, greenhouse gas emissions allowances.

With the Midwest Governors Association and the U.S. federal government actively considering cap and trade programs, there is a possibility that carbon dioxide and other GHGs may have an established market price within the next few years. In the three percent scenario described above, we generalized that wind and solar electric systems would be displacing natural gas combined cycle electric generation and that biomass would be reducing baseload coal plant operations on a one-to-one kWh basis. We used RETScreen International's® rate of reduction of carbon-equivalent emissions of 0.0005 tons per kWh for natural gas and 0.001 tons per kWh for coal.

The greenhouse gas emissions reduction per kWh is much higher for manure digesters operating on CAFO dairy farms due to the disproportionate climate forcing impact of methane reductions relative to carbon dioxide. This impact can be more than four times as high per unit of energy produced. Using 0.0045 tons of carbon equivalents per kWh (Mangino; Vries; Authors' Calculations) for avoided methane emissions, we estimated the following potential economic benefits shown in Table 25:

Table 25: Cost per ton of avoided carbon emissions

	Generation (kWh/year)	Tons/kWh	Emissions Reduction (tons)	$/ton
Digesters	315,360,000	0.0045	1,419,120	$8
Biomass	1,257,364,863	0.0010	1,257,365	$122
Wind	71,487,208	0.0005	32,169	$133
PV	71,487,208	0.0005	32,169	$933
		Total	2,740,823	tons per year
	Market Price $10/ton Carbon:		**$27,408,233**	
	Market Price $20/ton Carbon:		**$54,816,467**	
	Market Price $40/ton Carbon:		**$109,632,934**	

Quantifiable Benefits of ART: Job Creation and Economic Development

A common argument in favor of distributed generation is that it creates more local jobs than central power stations per MW of installed capacity. For example, solid biomass has been claimed to require 1.5 to 3 times as many full time workers per MW relative to coal power. In our three percent Wisconsin ART scenario resulting in 169 MW of bio-power, by this logic one would expect over 400 additional jobs in the electric generation operations and maintenance area alone. Including expanded employment to harvest, aggregate, transport, and process solid biomass feed-stocks could substantially increase that figure.

Jobs lost are also an important consideration for policy makers weighing the costs and benefits of various possible ART policy structures. This is a more difficult economic metric to forecast because it would require collecting data on a hypothetical question. Namely, what would Wisconsin ratepayers have been spending money on otherwise that is now going toward electric bills to cover the increased percentage of paying for ART energy payments? Is this in-state or out of state spending, and how does it impact employment?

Analogous to the job creation issue is the broader economic impact analysis of ART policy designs under consideration relative to other options for meeting environmental and economic policy goals. Renewable advocates in Wisconsin for years have advocated reducing the state "energy deficit", approximately $13 billion annually spent to import fossil fuels from out of state, under the rubric of energy independence and keeping investment dollars at home.

A full economic impact study, using primary empirical research, for each ART candidate technology is needed before drawing conclusions about the economic development multipliers of renewable energy expansion. While it is difficult to argue that $1 invested in solar capital costs does not have some reducing effect on the amount of natural gas that would need to be imported into Wisconsin given that the ART by definition imposes a priority purchase obligation on utilities, the question is how much and the ratio between the two. Does $1 of photovoltaics buy $10 worth of electricity that otherwise would have been spent on natural gas? Or does it only displace five cents worth of natural gas, and misallocate the other 95 cents?

Assessing the Value of Qualitative and Other Potential Benefits of ART

In the examples above, we have discussed a range of possible ART costs that would need to be paid by ratepayers. Reductions in GHG emissions, job creation, and economic development resulting from investment in Wisconsin renewable energy production infrastructure are all possible areas that could provide measureable, predictable benefits to the people and environment. Other possible quantifiable benefits may include incremental reduction in line losses due to reduced average distances between generation and load; greater diversity of energy sources for power generation; increased incentive for renewable energy system equipment and component manufacturers to locate or expand facilities in Wisconsin; and increased state income tax revenue.

One framework for policy makers to consider when assessing energy policy alternatives is to consider the value residents and elected officials place on the possible qualitative benefits resulting from an ART policy.

Concluding Remarks

The Task Force's renewable tariff recommendation, at the most fundamental level, is based on a policy philosophy of answering the question: "We have a goal to expand to renewable energy in Wisconsin, so what is the best way to get there?" The Task Force's answer, which is supported by evidence from many other successful ARTs, is that people need a guarantee that a very high capital investment will pay off in a reasonable period of time. This is evidenced both by how new U.S. wind investments have been tied to the PTC and by the difference in how the recession has affected the renewable industry in places with guaranteed price contracts compared to those that do not.

In places where ARTs are most effective, investors in renewable energy receive energy payments in order to guarantee a profit to anyone who invests in renewable energy. However, issues that change the economics include whether other subsidies (Focus on Energy, for example) apply, whether generation is taxable income, and who pays for access.

ARTs have no constraints regarding which technology to choose or a methodology to calculate price. We chose not to compete with a RPS, and instead complement it by supporting local generation that is not likely to be developed by the existing RPS. We found that the differential in generation costs will result in $199 million more with the policy than without it. However, other benefits exist in the form of creating jobs and reducing greenhouse gases, particularly methane.

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Appendix I – Biogas RETScreen Figures

Table I.1. Anaerobic digester scenario assumptions for simulations in RETScreen International®

Power Capacity	0.2 kW/cow
Type of Anaerobic Digester	Plug-Flow
Project Life	20 years
Capacity Factor of AD	90%
Federal Grant (REPI)	$0.021/kWh for 10yrs
Renewable Energy State Tax Exemption	100% Sales Tax Exemption
Bedding Recovery	1.5t/cow/yr
Bedding Value	$20/t
Debt Term	15 years
Capital Costs	$846,128 to $977,316 (500 cows: $8,461 to $8,773/kW) $1,095,263 to $1,120,670 (750 cows: $7,303 to 7,471/kW) $1,264,024 to $1,315,351 (1000 cows: $6,320 to $6,577/kW)
Annual O&M costs	$0.0200/kWh (100 kW system) $0.0175/kWh (150 kW system) $0.0150/kWh (200 kW system)

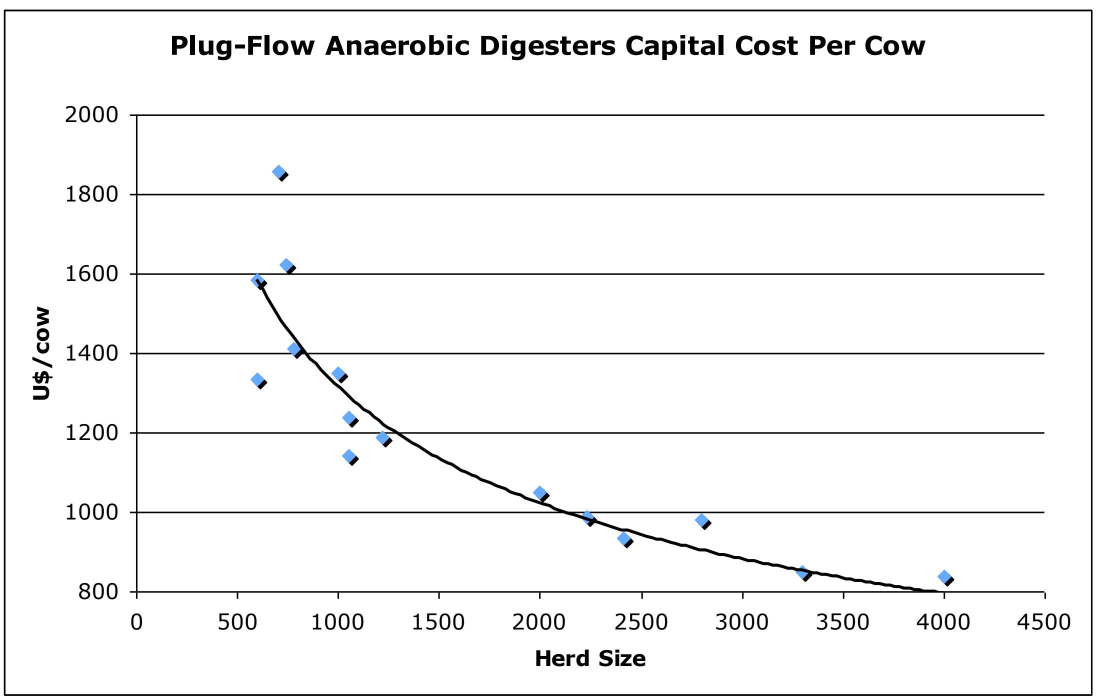

Figure 1. Plug-Flow anaerobic digesters capital costs = U$ (16201 x number of cows^-0.3635) per cow (referred in this handbook as capital costs "level B")

Table I.2. Energy payments to provide 12.5% IRR on Anaerobic Digesters in WI dairy farms for a multitude of scenarios

			Energy Payments ($/kWh)																	
			Fixed									Inflation adjusted (2.5%)								
			Debt interest rate: 4%, Debt ratio: 25%			Debt interest rate: 8%, Debt ratio: 80%			Debt interest rate: 6.75%, Debt ratio: 80%			Debt interest rate: 4%, Debt ratio: 25%			Debt interest rate: 8%, Debt ratio: 80%			Debt interest rate: 6.75%, Debt ratio: 80%		
Herd Size	Project Size	System type and Capital cost ($/kW)	10 yrs	15 yrs	20 yrs	10 yrs	15 yrs	20 yrs	10 yrs	15 yrs	20 yrs	10 yrs	15 yrs	20 yrs	10 yrs	15 yrs	20 yrs	10 yrs	15 yrs	20 yrs
500 cows	100 kW	Plug-Flow A: 9,773	0.163	0.146	0.139	0.146	0.132	0.126	0.135	0.123	0.118	0.139	0.123	0.116	0.123	0.111	0.105	0.113	0.103	0.098
		Plug-Flow B: 8,461	0.136	0.124	0.118	0.121	0.111	0.107	0.112	0.103	0.100	0.114	0.104	0.099	0.101	0.093	0.089	0.093	0.086	0.083
		Complete-Mix: 6,746	0.101	0.094	0.091	0.089	0.084	0.082	0.082	0.078	0.077	0.083	0.078	0.076	0.072	0.070	0.069	0.066	0.065	0.064
750 cows	150 kW	Plug-Flow A: 7,471	0.111	0.103	0.099	0.098	0.092	0.089	0.090	0.085	0.083	0.092	0.086	0.083	0.081	0.077	0.075	0.073	0.071	0.070
		Plug-Flow B: 7,302	0.108	0.100	0.097	0.095	0.089	0.087	0.071	0.069	0.068	0.090	0.084	0.081	0.078	0.074	0.073	0.087	0.083	0.081
		Complete-Mix: 5,541	0.072	0.070	0.069	0.062	0.062	0.062	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*
1000 cows	200 kW	Plug-Flow A: 6,320	0.084	0.080	0.078	0.073	0.071	0.070	0.066	0.065	0.065	0.068	0.066	0.066	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*
		Plug-Flow B: 6,577	0.089	0.085	0.083	0.078	0.075	0.073	0.071	0.069	0.068	0.073	0.070	0.069	0.072	0.072	0.071	*0.060*	*0.060*	*0.060*
		Complete-Mix: 4,939	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*	*0.060*

Note: minimum energy payments of $0.06, assumed as the base energy price.

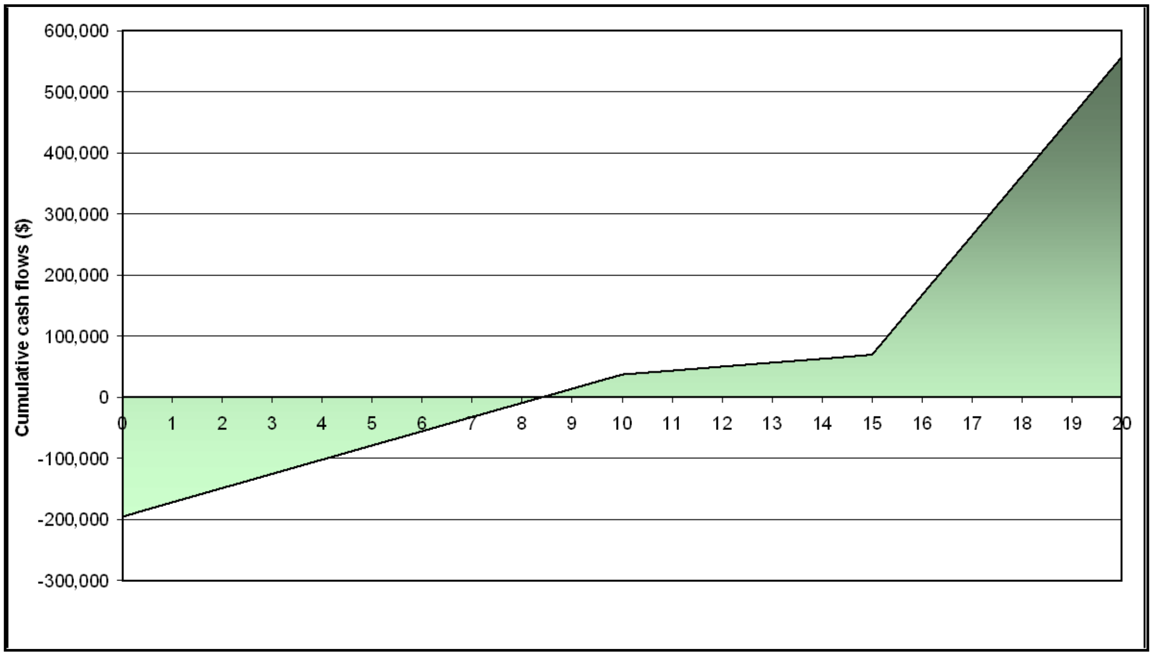

Figure 2. Cumulative cash flow (U$) for: 500 cows herd, capital cost U$ 9773/kW, fixed energy payment of U$ 0.126/kWh for 20 years. Simple payback time: 8.5 years. Equity payback time: 8.4 years.

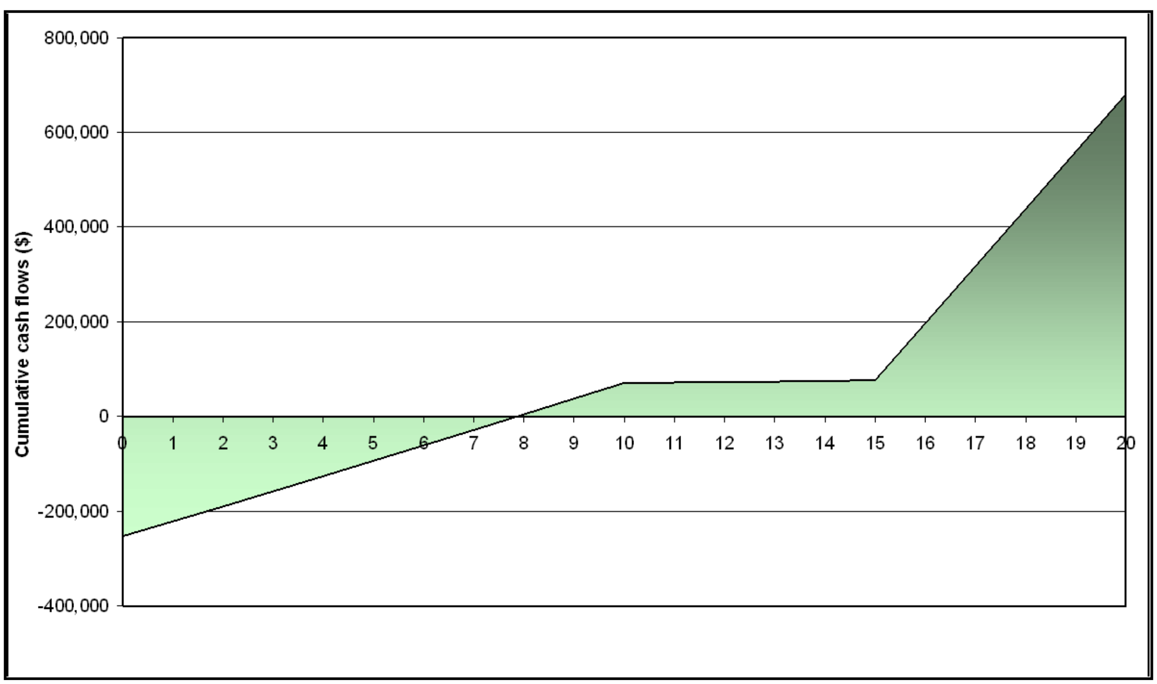

Figure 3. Cumulative cash flow (U$) for: 1000 cows, capital cost U$ 6320/kW, fixed energy payment of U$ 0.070/kWh for 20 years. Simple payback time: 8.5 years. Equity payback time: 7.9 years.

Appendix II – Biomass Figures

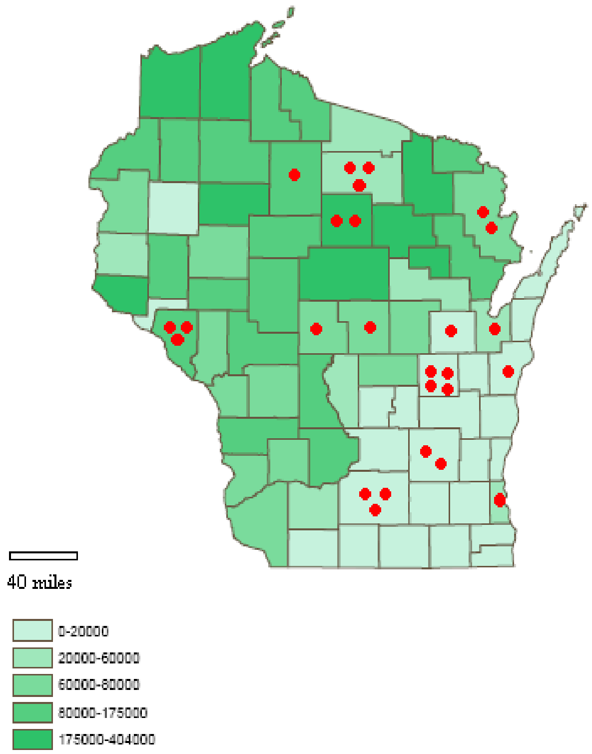

Figure A.1. Annual Tree Removal By County in Dry Tonnes & Small Coal Plants in WI

Table A.1. Summary of Assumptions for Simulations using RETScreen International ®

Power Capacity	500kWe and 8,400kWe
Project Life	30 years
Capacity Factor	85%
Federal Grant (REPI)	$0.021/kWh for 10yrs
Fuel Cost (45% moisture)	$15-25/tonne
Natural Gas Cost	$6/MMBTU
Renewable Credit Length	20 years

Table A.2. Steam Turbine Input for RETScreen International ®

	500kWe	**8,400kWe**
Steam Flow [lb/hr]	62,978	708,652
Operating Pressure [bar]	19	52
Superheated Temperature [ºC]	257	399
Back Pressure [kPa]	103	1,034
Steam Turbine Efficiency	12%	24

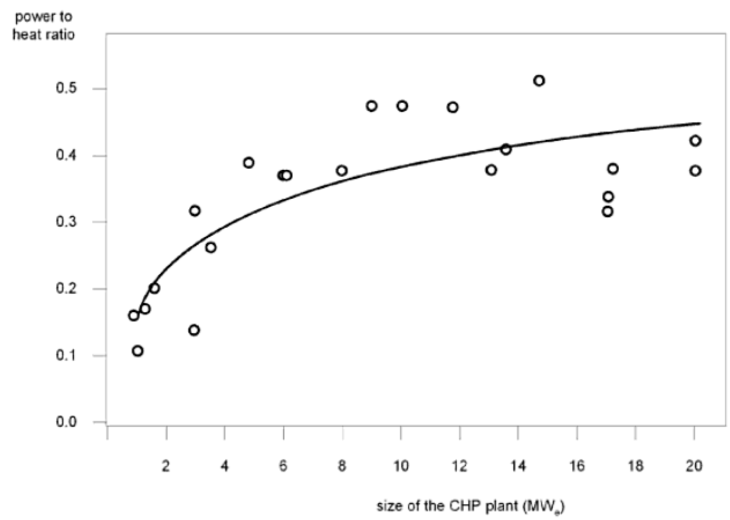

Figure A.2. Power-to-heat ratio as a function of the plant size of biomass-fuelled CHP plants in Finland and Sweden with 1-20MWe

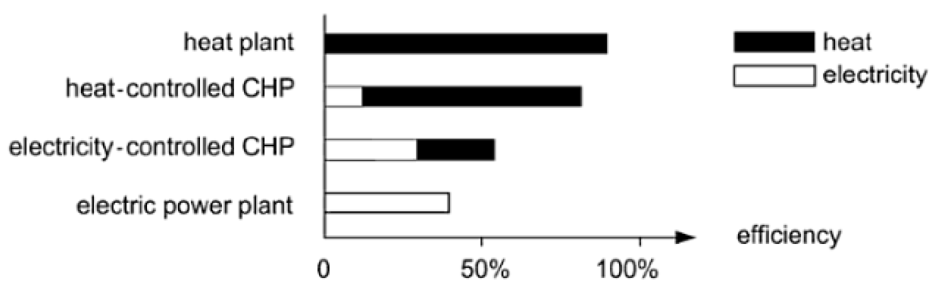

Figure A.3. Percentage of heat and electric power production in heating plants, CHP plants and power plants (qualitative figures)

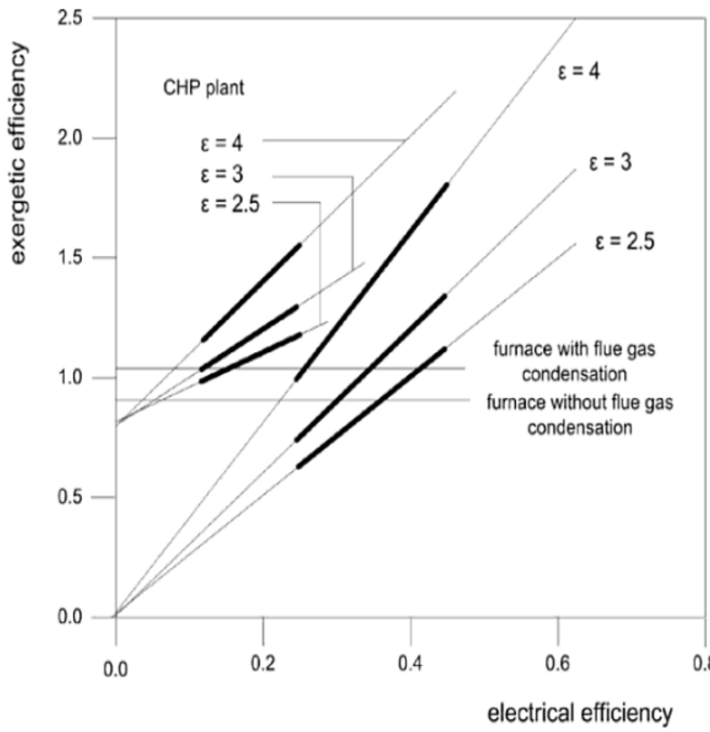

Figure A.4. Comparison of heat, CHP and power plant efficiencies by an exergetically weighted efficiency

Appendix III - Summary of Renewable Feed-in Tariff Survey Responses

Note this summary is for reference only and is not comprehensive. Most, but not all, of the survey responses are summarized here in detail.

Wisconsin Public Service Commission: Investigation on the Commission's Own Motion Regarding Advanced Renewable Tariff Development

Docket ID: 5-EI-148
Docket Contact Person: John Shenot, Policy Advisor

Respondents to the Survey:

	Organization Name	Abbreviation	Organization Type	Comment Author
1	RENEW Wisconsin	RENEW	Advocacy Group	Michael Vickerman
2	WI Cast Metals Assn. and WI Industrial Energy Group	WCMA/WIEG	Advocacy Group	Robert Peaslee
3	Wisconsin Dairy Business Association	WDBA	Advocacy Group	Laurie Fischer
4	Wisconsin Farmers Union	WiFarmUn	Advocacy Group	Sue Beitlich
5	AgrEnergy	AgrEnergy	Biodigester Business	Daniel De Buhr
6	Biomass Solution LLC	BioSol	Biodigester Business	Monte Lamer
7	Clear Horizons, LLC	ClearHor	Biodigester Business	Daniel Nemke
8	Energies Direct LLC	EnergyDir	Biodigester Business	Michael Zander
9	GHD , Inc	GHDinc	Biodigester Business	Stephen Dvorak
10	Green Valley Dairy	GVDairy	Biodigester Business	
11	Hanusa Renewable Energy	HanusaRE	Biodigester Business	Duane Hanusa
12	StormFisher Biogas	SFBiogas	Biodigester Business	None
13	StormFisher Biogas	SFBiogas	Biodigester Business	Ryan Little
14	Suring Digester, LLC	SurDigester	Biodigester Business	Raymond Leicht
15	Public Comment – Eric Nottestad	Enottestad	Citizen	Eric Nottestad
16	Public Comment – Michael J. Tiry	MJTiry	Citizen	Michael J. Tiry
17	Cooperative Network	CoopNet	Electric Utility	William Oemichen
18	Dairyland Power Cooperative	DPC	Electric Utility	Brian Rude
19	Madison Gas and Electric	MGE	Electric Utility	G Bollom
20	Municipal Electric Utilities of Wisconsin	MEUW	Electric Utility	David J. Benforado

21	Northern States Power Company (Xcel Energy)	**NSPW**	Electric Utility	Karl Hoesly
22	We Energies	**WEPCO**	Electric Utility	Roman Draba
23	Wisconsin Electric Cooperative Association	**WECA**	Electric Utility	Share Brandt
24	Wisconsin Power and Light / Alliant Energy	**WPL**	Electric Utility	Scott Smith
25	Wisconsin Public Service Corporation	**WPSC**	Electric Utility	
26	Wisconsin Utilities Association	**WiUtilAssn**	Electric Utility	Bill Skewes
27	WPPI Energy	**WPPI**	Electric Utility	Michael Stuart
28	Comments of Dane County Supervisors	**DaneSup**	Government	
29	Dept of Ag, Trade, and Consumer Protection	**DATCP**	Government	Rod Nilsestuen
30	Forest Country Potawatomi Community	**PotawComm**	Government	Jeff Crawford
31	Wisconsin Legislature Assembly on Agriculture	**WiLegAg**	Government	Amy Vruwink, Chair

Survey Takeaways

- Electric cooperatives are not subject to PSC jurisdiction
- Governor's Task Force on Global Warming (Task Force) proposes enhancing renewable development with support from the state general fund, rather than through PSC mandated tariffs
- Task force recommends PSC should implement tariffs to encourage renewable development (pg 26), but this conflicts with biogas recommendation on pg 173
- **WECA** represents all 24 not-for-profit Wisconsin electric distribution cooperatives, which service 267, 000 consumers of electricity. Co-ops rates not regulated by PSC because electric rates are set by co-ops member elected boards of directors. "We are concerned that any PSC rule making on ARTs could be perceived as altering this process."
- **WUA** - Final report of Governor's Task Force on Global Warming identified ARTs as an enabling policy to an Enhanced RPS, meaning that ARTs are not expected to reduce GHGs directly. ARTs enable in two ways: (1) May expand the development of smaller scale projects, (2) Smaller scale projects may be necessary given the scale of renewable generation deployment necessary to meet Enhanced RPS. Basically this means that an ART policy does not have an associated GHG reduction and renewable generation goal, it is part of a larger plan (RPS) which has those goals, and uses ARTs to help meet the goals.

- **WUA** – Governor's Task Force Report also identified the need to: "pay particular attention to measures that will less the burden of addressing climate change on consumers, and on energy-intensive industries like paper production and operate in highly competitive global environments, while providing essential jobs and other benefits to their communities."

- **WUA** - **Two general principles are critical**: (1) Keep ART design simple and easy for potential customer participants to understand, (2) Use care in designing programs to minimize opportunities for manipulation or unintended consequences.

- **WUA -** ART design components will need to be tailored specifically to overarching policy objective – policy objective examples are: to help meet RPS mandate, achieve certain level of small customer-owned renewable energy projects, or to supply a local distributed resource for voluntary green energy program.

General Comments:

Organization	Comment Summary
CoopNet	Price discrimination results from ART for coop members, which may have disproportionate number of digesters or other renewable sources
DPC	Establishes ART for <2MW projects. Wind - $0.065/kWh, Biogas – $0.105/kWh on peak & $0.054/kWh off peak. Cap 2MW nameplate capacity per distribution feeder line.
MEUW	Supports WPPI Energy's recommendations
MGE	"Because each customer-owned installation is unique, there was no average or typical installation upon which to develop a cost based price."
MGE	Because **MGE** purchases the energy directly from customer-owned installations, **MGE** has no investment in any of the installations and as such green pricing program has no affect on **MGE**'s utility return.
WEPCO	ARTs put upward pressure on electric rates, market price for renewable energy, and on utility administrative costs (added personnel and infrastructure necessary to manage a large number of small electric production accounts and substantial utility billing system modifications)
WEPCO	Use of ARTs to contribute significantly towards RPS compliance would "add significant cost to the fulfillment of this obligation over that of more centralized larger renewable generation"
WECA	Cooperatives serve areas with small customer base but large potential for renewables. "Since all users of electricity would benefit from the availability of renewable energy, consideration should be given to provide for equal cost sharing measures."
WECA	Must consider possible additional costs to upgrade distribution and transmission systems to accommodate customer-owned generation.
WPSC	Requires participants in solar art to respond to survey regarding installation and operation costs and issues and the main drivers motivating the customer purchase.
WPPI	Believes commission should encourage and facilitate development of distributed renewable projects even though they are not cost effective when compared to utility scale projects. It is valuable to encourage distributed renewable because it increases diversity of renewable resources, helps utilities to gain a better understanding of emerging technologies, and increased development may reduce installation costs.
WPPI	Programs that are "simple, straightforward, easily understood, and predictable" will best facilitate the understanding and adoption of distributed renewable by consumers.
WPPI	Urges commission not to develop a "one size fits all" template for distributed renewable

	projects because multiple templates will be necessary to accommodate the different needs of not-for-profit electric power companies like WPPI and investor-owned utilities.

DaneSup	Strongly support establishing WI ART
	• Use of ARTs in Germany, France, and Spain have propelled these countries to the forefront of renewable energy development an created hundreds of thousands of new jobs
	• ARTs are more equitable than other policies because they enable everyone – farmers, cooperatives, homeowners, businesses large and small – to become renewable energy producers
	• ART rates should be based on production costs, so price should be different for solar, wind, biomass, biogas, and other renewable
	• Claim that within a particular fuel category and generator size, installation and operating costs will be uniform regardless of location
	ARTs should be structured around following principles:
	    • Focus on removing barriers to smaller renewable distributed generation
	    • Balance WI RPS and value of renewable electricity to ratepayers
	    • Energy procured by utilities under tariff should be eligible to comply with WI RPS or to a green pricing program, but not both
	    • Price elements should be kept simple
	    • Inflation adjusted 10 to 15 year contract lengths

DATCP	Strongly supports expanded use of WI ART
	ART will:
	    • Result in hundreds of on-farm methane digesters
	    • Greater use of homegrown biomass for heat and energy
	    • Create a fast track for cellulosic ethanol development in WI
	ARTs provide the following societal benefits to WI ratepayers:
	    • **Investment Dollars Locally:** ART results in projects financed in Wisconsin – financial benefits accrue to Wisconsin residents by providing them directly with the cash flow to obtain financing of renewable energy generation.
	    • **Magnets for Capital:** ARTs assure investors a steady income stream will exist through a longer term tariff, and will therefore make it easier to raise capital even during the present economic downturn.
	    • **New Wisconsin Jobs and Economic Growth:** Will result in many new businesses and new jobs.
	    • **Addressing climate change in Wisconsin:** Methane digesters have two positive climate effects: (1) generate renewable energy from a waste stream reducing the need to use coal, etc, (2) Capture and burn methane that would otherwise have been emitted into the atmosphere.
	    • **Community-based Solutions & Local Ownership**: Can enable cooperative or community ownership models for WI, which can reduce NIMBYism, diffuse market control by a handful of players, and create more distributed, locally owned, and democratic energy system.
	Existing ART – basically ART not a new policy tool, gives an outline of ARTs in place
	    • Germany jobs – 35,000 employed in solar industry, 70,000 in wind. Direct and indirect employment in renewable energy sector in Germany was 214,000 in 2006.
	    • German ART costs are evenly distributed among ratepayers – WI should do the same
	    • Biodigesting – Germany has 8,000 jobs in on-farm biogas industry. Manure fired power plants generate 5 billion kilowatt hours per year – 1% of consumption (about

	8% of WI consumption) • German tariff shown to have lower resource-adjusted cost to society than British system of trading credits Term of contract – minimum 10 years, preferably 15 or 20 Biogas • Cites Alliant Energy study describing biodigester capacity and benefits Regional Methane Digester Opportunities in WI • Dane and Brown county are investigating opportunities for regional methane digesters • Agriculture and Food Processing are a $51 billion economic sector in WI, provide 12% of jobs – large opportunities to digest food processing wastes WI Biomass Opportunity • Key – need to build up a market to grow, harvest, aggregate, and deliver biomass to the end user • Encouraging small projects first may build industry capacity • Wood and agricultural waste to energy projects also important To create the Building Blocks for a New Economy in Wisconsin should: • provide incentive to convert more state burners to operate on biomass (Fuel to Schools program) • Encourage ethanol plants to shift to biomass for power • Enhance use of CHP • Infrastructure is critical for WI to make next step to cellulosic ethanol
FCPC	Tribe is very concerned about potential environmental, economic, and other effects of climate change – Tribe is also a significant customer of two of WI largest utilities, so tribe has significant interest in keeping electricity affordable As Commission is aware, Task force formed to pursue Executive Order 191. Task Force missions: • Present viable, actionable policy recommendations to reduce GHG emissions in Wisconsin and make Wisconsin a leader in implementation of global warming solutions. • Advise on ongoing opportunities to address global warming locally, while growing our state's economy, creating new jobs, and utilizing an appropriate mix of fuels and technologies in Wisconsin's energy and transportation portfolios. • Identify specific short- and long-term goals for reductions in GHG emissions in Wisconsin that are, at a minimum, consistent with Wisconsin's proportionate share of reductions that are needed to occur worldwide to minimize the impacts of global warming. ART policy contained in task force is a key component to meet task force missions – example if 3% of utility generation from small distributed renewable resources by 2025, this would result in 2.25 million metric tons/year of CO_2. ART also ensures we address global warming locally. Task force final report recommends that ART policy should encompass following principles: A. Tariffs should be set according to specific production costs of a particular generation technology. B. The tariffs should include a rate of return comparable to the utilities' allowed return. C. The tariffs should be fixed over a period of time that allows for full recovery of capital costs. D. Renewable energy credits acquired through these tariffs can be rate-based or sold

	through a utility's voluntary renewable energy program. E. When the fixed term of the tariff ends (capital costs of project have been recovered), the energy from these systems can be acquired through the utility's parallel generation tariff or through a negotiated purchased power agreement. Provided that ART provides full cost recovery – removes major obstacle to small renewable development, particularly for local governmental entities and other non-traditional providers that can be important sources of renewable Energy Allowing RECs created through tariffs to be rate-based or sold through utilities voluntary green pricing programs allows ART to help meet state RPS and increasing demand for voluntary purchases of renewable energy Task Force Recognized importance of encouraging small renewable in-state energy development even to the extent it increases costs: "It is recognized that Advanced Renewable Tariffs would likely result in increased costs per unit of electrical output compared to utility-scale renewable projects, but that these costs are justified by the economic and environmental advantages from encouraging distributed small-scale generation." Tribe recommends Commission consider developing two sets of tariffs to prevent Wisconsin electric customers from unduly subsidizing large, established for-profit renewable energy developers: (1) Set of tariffs for entities such as the state, local governments, tribes, and publically-owned treatment works ("local communities"), which are key sources of potential renewable energy and which are permanently located in Wisconsin. These local communities, unlike for-profit entities, cannot receive federal production or investment tax credits or even federal energy grants under the stimulus package that President Obama is to sign today. Thus, local communities are unlikely to receive any undue subsidies because of ARTs. Moreover, local communities are generally required to share any financial benefits with their residents, members, or users. Thus, for local communities, ARTs should clearly be based on the full cost of the renewable generation facilities, as outlined in the Task Force ART policy, as well as all the system benefits that the renewable energy provides. (2) Second set of ARTs that may be somewhat more restricted in terms of payments and participation for situations where the owner of the facility is more likely to be a larger developer, who docs need a special tariff rate to successfully develop a project and would generally not share the financial benefits of the tariff with the members of the local community.
WFU	Implied preference for statewide, uniform, renewable energy buyback programs. **Problems with existing experimental ARTs are that they:** • are not uniform • are linked to voluntary green pricing programs of individual utilities instead of entire rate base • provide sometimes inadequate rates • have limits on the type and eligible size of the generator and total capacity of the program **Claim renewable energy buyback programs:** • Are more equitable than policies that favor larger institutional projects • stabilize the marketplace for the development of renewable energy

	• reduce volatility of future electricity prices • lower long-term cost of electricity • reduce greenhouse gas pollution Point out that Germany has a very successful renewable program and that buyback programs are catching on with legislation introduced in three states: Michigan (Sponsor Kathleen Law introduced in 2007l HR 5218), Illinois (Sponsor Rep. Karen May; HB 5855) and Minnesota (Sponsors: Bly, Hilty, Knuth, Kalin, Peterson, A.; HR 3537). Also Representative Jay Inslee of Washington has also introduced legislation in Congress.
DBA	Members experience is limited to manure digesters, so response to Commission's questions focus on technology and economics of manure digester technology. However, there are opportunities for wind and solar on farms, so these are of importance to DBA as well.

WCMA/WIEG	**WCMA** - Trade association, represents some of the state's largest energy consumers and one of the most energy intensive industries. 40 member foundries in an industry employing 19,000 persons with $745 million payroll and $3 billion in sales
	WIEG – Non-profit association of many of WI largest energy consumers and advocates for policies supporting affordable reliable energy. Member companies spend $200 million on electricity annually (about 3% of state electricity consumption) and employ 50,000 WI residents. Represents most major WI manufacturing industries.
	
	Comments focus primarily on policy questions, and to a lesser extent design –
	(1) Should the availability and use of ARTs be expanded?
	(2) If ARTs are expanded, how should costs be allocated?
	
	• Using ARTs to meet a future RPS cannot be justified economically
	  ○ Even today – renewable energy comes at a price premium over traditional, carbon based generation.
	  ○ ARTs are likely to be even more expensive, carrying premium on top of already high renewable energy premiums – double hit for ratepayers
	• ARTs do not themselves "directly lead to any greenhouse gas ("GHG") emission reductions." (WISCONSIN'S STRATEGY FOR REDUCING GLOBAL WARMING, p. 120, Governor's Task Force on Global Warming Final Report, July 2008. (note, this comment is misleading, it really means ARTs are only a part of a larger policy, such as an RPS, which has a result of reduced GHG emissions.
	• Cost of ARTs should be borne by ratepayers who affirmatively agree to pay such premiums
	• Primary objective in evaluating an ART
	  ○ Ascertain if ART will result in WI meeting RPS in a least-cost manner
	  ○ Cost crucial considering economic slow down
	  ○ WI 2005 Act 141 contains "off ramps" which can be triggered for unreasonable rate impacts derived from the RPS statute
	• Industrial customers support alternatives to ARTs
	  ○ Prefer least cost outcomes – competitive bidding for example
	  ○ Customers should not bear risk/costs for introducing new/high cost technologies
	  ○ Competitive bidding enables third parties to take risk instead of customers
	• Purpose that ARTs are intended to serve is unnecessary in WI
	  ○ ARTs used in Europe primarily in lieu of a mandatory RPS
	  ○ CA – felt ARTs could play a role to meet RPS obligations that were unlikely

	to be met in absence of their use ◦ WI though has mandatory RPS, and obligations are being met satisfactorily. PSCW announced all 118 WI electric providers have met RPS requirements, and 111 exceeded requirements. ◦ Not clear that ARTs are required in any meaningful way • ARTs need to adhere to traditional regulatory and rate making principles ◦ Commissioners concerned in recent docket on cost allocation (05-UI-113) about – cost causation, equity, and facility of implementation ◦ ARTs should not run counter to traditional principles – cost, need, and reliability • Industry customers suggest ◦ If Commission considers broadening ARTs – c**ost should be allocated to the customers participating in voluntary green pricing programs** ◦ ART should only be designed to meet the demand of the subset of customers that is willing to pay a premium for the renewable attribute associated with its power use – **fair and equitable way to introduce ARTs should commission decide to do so**

Responses to Specific Questions:

ART Experience to Date in Wisconsin and Elsewhere

1. Wisconsin utilities for which the Commission has previously approved an experimental ART are asked to respond to Questions 1.a. through 1.e.

a. How did the utility decide upon the design and price of each ART?

- **MGE** "reviewed similar programs offered by other utilities, discussed economic requirements with local solar advocates, and reviewed past customer research and field staff experience" "set at a level the Company felt would be just high enough to attract customer participation"
- **NSPW's** experimental ART based off information provided by Wisconsin Distributed Resources Collaborative (WDRC). WDRC's information based off other states and countries ARTs.
- **We Energies –** We Energies Renewable Collaborative (WEREC) provided input.
  - **Solar Buy-Back Tariff** – set based upon input from focus on Energy staff and WI PV installers. Rate selected to motivate customers to participate.
  - **Biogas Buy-Back Tariff** – Set price level to encourage on peak generation and to result in new generation units and continued generation from existing units. Project cap of 1000kW and program cap of 10MW.
  - **Expanded Wind Net Metering Tariff** – customers with wind generation between 20kW and 100kW may net meter. Limited to first 25 customers to enroll.
- **WPL –**
  - **Pgs-6 Biogas tariff** – Started 4/30/02, closed to new customers 12/31/07. Generation cap 800kW, program cap 10MW. 5 year contracts, $0.08/kWh on-peak & $0.049/kWh off-peak. Rates set to provide adequate return of investment and to encourage development of these technologies.
  - **PgS-ART** – Effective 1/1/09. Solar resources - $0.25/kWh, non-solar resources (biomass, wind, small hydro, other renewable) - $0.12/kWh on-peak, $0.0735/kWh off-peak. Solar project cap 20kW, program cap 683kW. Biomass/Biogas project cap 2MW, other renewable project cap 1MW, overall program cap 0.5% of the Company's retail electric kWh sales from prior calendar year. 10 year contract. Solar rate based on economic analysis from WECC. Rates set at level estimated to provide adequate ROI and to encourage customer participation.

- **WPSC** – **Solar ART** (UR-119 rate case) implemented 1/1/2009. $0.25/kWh paid, cap set at 300kW. Price set at level felt to be high enough to attract customer participation.

b. What effect did each ART have in terms of number of participating customers, enrolled capacity, and actual generation?

- # of participating customers – 61, enrolled capacity – 305kW solar, actual generation – 42 projects installed and generating (**MGE**)
- **NSPW** – None, no enrolled customers.
- **WEPCO**
  - **Solar Buy-Back Tariff** – As of February 10, 2009 146 customers enrolled for a total of 987kW, with 737 kW already interconnected. 2008 customer owned solar generation – 650MWh.
  - **Biogas Buy-Back Tariff** – As of February 10, 2009 3 customers have enrolled in the tariff with a total capacity of 830kW. Total 2008 generation from these 3 generators was 5199MWh.
  - **Expanded Wind Net Metering Tariff** – As of February 10, 2009 2 customers enrolled with total capacity of 125kW. Total 2008 generation from these two wind generators was 94MWh.
- **WPL –**
  - **Pgs-6 Biogas Tariff** resulted in one renewable energy installation, 200kW Double S Dairy digester. Lack of participation suggests rates and incentives were too low.
  - **PgS-ART** has not been in place long enough to yield results. Number of inquiries and enthusiasm suggest solar limit will be met in <1 year, all other renewable < 2 years.
- **WPSC** – Solar ART implemented 1/1/2009, but 40kW of installations already under contract.

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c. To date, how would the total cost to the utility of each ART compare to market rates for electricity and market rates for electricity generated from renewable resources?

- $250/MWh for solar compared to a little under $70/MWh average for on-peak electricity and $40-$60/MWh for other renewables (landfill gas and variety of wind resources) (**MGE**)
- ART prices approximately 25% higher than MISO day-ahead market prices (**NSPW)**
- Price is set above utility scale renewable generation as means to motivate participation in the tariff, but participation limits are set to cap impact on electricity prices (**WEPCO)**
- **WPL** – WPL's parallel generation tariffs (PgS-1 and PgS-3) establish level of compensation at a fixed price per unit comparable to avoided cost (determined from forward looking test year. Current tariff level is $0.0809/kWh during on-peak (8 a.m. to 10 p.m. weekdays) and $0.035/kWh during off-peak, compared to PgS-ART rate of $0.25/kWh for solar and $0.12/kWh on-peak and $0.0735/kWh off-peak for all other renewable.
- **WPSC** – Solar buyback rate is $0.25/kWh, compared to 2008 on-peak LMP of a little under $70/MWh for WPSC load zone and average cost of other renewable energy sources of $0.05 - $0.12/kWh depending on on-peak generation percentages.

d. What effect, if any, have ARTs had on utility rates, voluntary "green power" prices, and utility returns?

- None on utility rates, energy used to supply Green Power Tomorrow (GPT) program. Insignificant impact on GPT rate because represents a small amount of total supply. No effect on MGE's utility return because MGE does not have an investment in any of the installations. (**MGE**)
- **WEPCO** Solar buy-back rate only impacts Energy for Tomorrow Customers – supplies 0.3% of energy and is 2% of the cost of renewable energy used for Energy for Tomorrow program.
- **WPL** – PgS-ART effective 1/1/2009, so non-solar options have not had an impact to date. Solar option costs are planned to be paid for through Second Nature green pricing program.
- **WPSC** – None on utility rates, solar ART intended to be paid for through NatureWise green pricing program.

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e. What contribution has each ART made toward utility compliance with renewable portfolio standard obligations?

- None, there is no double counting, all energy is used to supply GPT (**MGE**)
- Solar energy supplies Energy for Tomorrow customers (**WEPCO**) **– [**did not state whether biomass and wind contribute towards RPS]
- **WPL** – Currently one project under ART, 190kW biodigester, not large enough to affect utility's RPS obligation – cost of tracking with M-RETs far outweighs value of REC. M-RETs expenses are: initial registration fee, annual fee, and fee for each REC transaction. If 2MW-5MW biogas projects were consider for ART, renewable energy generated would contribute substantially to RPS obligations and M-RETs tracking fees would be reasonable.
- **WPSC** – None, solar ART energy used to supply NatureWise green pricing program.

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2. Research and Experience Outside Wisconsin

a. Can you identify any research or reference documents that you believe will enhance the Commission's understanding of ART design issues and/or the actual documented effects of ARTs outside Wisconsin? Please provide enough information for Commission staff to locate such documents; it is not necessary to provide copies.

- **FCPC** – Wind Works material: http://www.windworks.org/FeedLaws/USA/Model/ModelAdvancedRenewableTariffLegislation.html
- **DBA** –
  - "Current Experience With Net Metering Programs" delivered at 1998 Wind Power Conference
  - "Freeing the Grid" – November 2006, produced by "Network For New Energy Choices"
- **BioSol**
  - Example: Germany has over 3000 digesters, majority privately owned and operated agricultural units fed with waste from farm and food production
- **GHDinc**
  - Vermont – pays dairy producers day ahead trading price plus $0.04/kWh for renewable-green energy that is sold to customers as Cow Power www.cvps.com/cowpower/
  - State of New York - $0.10/kWh and net metering increment to 500kW/hr – utility retains RECs and farmer retains CCs www.nyserda.org/funding/1146PON.asp
  - Tri-State Generation and Transmission Association, Inc., serving customers in Nebraska, New Mexico, and Wyoming passed tariff mandate which has generated tremendous interest – www.tristategt.org/greenpower

Costs of Producing Electricity from Renewable Resources

3. What might it cost the typical customer of a Wisconsin electric utility to construct/install a new renewable energy system using each of the following technologies? What might the typical customer's lifetime operation and maintenance costs be? Please be explicit about sources of data, assumptions, and how costs might vary based on system size, location, or other variables.

a. Solar Photovoltaics (PV)
b. Wind
c. Landfill Gas
d. Biogas other than Landfill Gas

- **DBA** –
  - 2005 cost of a digester and related necessary equipment - $325-$550 per cow.
  - Cost varies with – system size and type, type of livestock operation, and site-specific conditions.
  - AgSTAR program has performed analyses to determine between capital cost and size for different types of operating digesters for dairy and swine manures with gen-sets. Results used in FarmWare 3.0

- **GHDinc**
    - Average costs of construction, genset installation, utility hookup, and waste handling – range of $1300-$1600 per cow designed capacity

e. Biomass
f. Hydroelectric
g. Any other renewable electricity technologies for which data are available

- **FCPC** –
    - Commission must consider "all-in" costs of building and operating facilities – these costs should include: capital costs, licensing, permitting, access and right-of-way needs, land owner compensation (including opportunity costs for the use of land and facilities, even if they are already owned by the developer of the renewable energy site), as well as the full life-cycle operating and maintenance costs – Critical to consider these costs so that Commission can develop ARTs that are consistent with the Task force ART policy which calls for ART participants to receive financial returns consistent with those provided to utilities
    - ART should account for added value of the electric system that is created through the implementation of small distributed renewable energy – benefits include avoided need for both transmission and distribution – so ART price should include avoided transmission and distribution costs
    - Tariff should likely include a "locational marginal costs differential" to account for avoided line losses associated with the small renewable generation facility
    - Recommend the Commission request utilities publicly report the full cost and performance of each type of renewable resource they have in their portfolio
- **BioSol** – basic response is that the cost of every project, renewable or not, varies due to numerous factors and details – it is therefore hard to determine specific costs

4. How much energy (in kilowatt-hours (kwh)) will be produced over the useful life of a typical customer-owned renewable energy system in Wisconsin using each of the following technologies? Please be explicit about sources of data, assumptions, and how production might vary based on system size, location, or other variables.

a. Solar
b. Wind
c. Landfill Gas
d. Biogas other than Landfill Gas

- **DBA** –
    - Production dependent upon type of digester (three types)
    - Production is base load, can reliably be expected to operate 8,000 hours per year
    - Haubenschild Farms, with 750 cows, has current output of 4.0kWh/cow/day.
    - According to company developing system: 4.8 MW facility will have total lifetime power output of 744,969 MWh and 20 year total aggregate output of 14.8MW installed base would be 2,296,960 MWh (assumes 89% capacity factor).
- **GHDinc**
    - Useful life of systems hard to estimate due to concrete construction and lack of oxidizing oxygen environment – estimate useful life of 30 years
    - Typical kW production per cow per day 4-6 kWh, 92% genset run time, 6% parasitic load
    - Genset operation costs – 1.5 cents/kWh generated by genset – supplier contracts available at this rate
    - $20,000-$40,000 per year for labor and AD system parts

e. Biomass
f. Hydroelectric
g. Any other renewable electricity technologies for which data are available

- **WUA – In response to 3 & 4**
    - Utilities have found there is no typical customer when it comes to customer-owned renewable energy systems because: cost and facility characteristics are site, technology, and size specific,

variances in customer use of electricity and customer goals for renewable technologies installation, and costs of customer owned facilities are not required to be provided to utility.
    - Energy Center of Wisconsin and Focus on Energy have reference materials and Wisconsin Distributed Resources Collaborative (WIDRC) has spent a great deal of time researching possible mechanisms for ARTs. Link to WIDRCs Tariff Committee webpage: http://www.wisconsindr.org/workinggroups.htm
- **FCPC** –
    - Biomass boilers up to 500,000 pph with 75 MW electric net output are possible
    - Hydroelectric from low-head run-of-river dams can run from 50kW to 2.5MW
    - Key to good public policy on sizing of generating units: source of fuel, location, environmental and logistics issues, and investment capital or other funding available
- **BioSol** – suggests the commission should research this topic and that the energy production is highly a function of the details of the project

ART Policy Issues

5. What should the goals and objectives of an ART policy be?

a. What would you consider to be the primary purpose of an ART policy? Is the primary purpose to accelerate renewable energy installations, lower the cost of renewable energy, help utilities meet renewable portfolio standard (RPS) obligations, increase the diversity of installed renewables, reduce greenhouse gas emissions, or something else?

- **WUA** - ART is a tool used to help achieve renewable energy objectives and/or reduce greenhouse gas emissions. Policy objectives may be: research based – to identify and evaluate technical and economic opportunities and barriers related to small-scale customer owned renewable in Wisconsin within the context of Act 141's public benefits and RPS provisions or to encourage development of educational and demonstration projects, implementation based – to encourage small customer-owned renewable energy systems, to diversify Wisconsin's renewable portfolio, or to decrease GHG emissions.
- **FCPC** –
    - Primary purpose: Address global warming locally, while growing State's economy, creating new jobs, and making the State energy independent through localized renewable energy.
    - ARTs should result in very significant amounts of new small in-state renewable energy generation.
    - Renewable energy from these facilities should become a significant portion of renewable energy used to meet the RPS and voluntary renewable energy sales
- **DBA** – With respect to manure digesters, primary purpose ART policy is to encourage development of manure digesters because it is a reliable source of power with substantial additional benefits: reduced GHG (methane) emissions, reduced nutrient storage problems, odor control, and reduced land spreading of farm waste.
- **BioSol** – goals are to increase diversity of generation and decentralize utility production while installing a sustainable infrastructure that produces renewable energy and decreases GHG emissions
- **GHDinc** – One purpose of ART policy is to promote AD generation. AD has substantial external benefits that should be captured.

b. Considering the primary purpose of the ART policy, what short- and long-term goals might be appropriate? In other words, how should the success of an ART policy be measured?

- **WUA** – Did not address question specifically
- **FCPC** –
    - Success should be primarily measured by level of participation (i.e. amount of small renewable generation which occurs due to ARTs)
    - Short term – number of projects that seek to participate under tariffs
    - Long term – measured by aggregate amount of renewable energy produced
- **DBA** – Job growth, investment in state by new or expanding companies responding to the demand for renewable energy equipment, percent increase in RPS targets met versus years where ART policy was not in place.

- **BioSol** – Success of ART can be measured by the number of participants (i.e. the amount of additional generation capacity resultant from the ART)

c. Should the Commission establish ARTs for all electric utilities regulated by the Commission, all investor-owned utilities or all Class A utilities? Why or why not?

- **WUA** – Did not address question specifically
- **FCPC** – All electric utilities regulated by the commission
- **DBA** – Commission should establish ARTs for all electric utilities under their regulation because the guarantee that a fair rate for power production will be offered regardless of location is important for energy developers.
- **BioSol** – Should establish ART for all electric utilities under their regulation – if utility sells energy in WI they should be working toward our common WI goals.

d. What role, if any, should small, customer-owned renewables play in helping utilities meet RPS obligations? Should utilities seek to meet RPS obligations at the lowest possible price, or should other factors be considered? What ART structure would best complement an RPS?

- **WUA** – Did not address question specifically
- **FCPC** –
  - Small, customer-owned renewable should play an important role in helping to meet RPS obligations
  - Task Force – Even to the extent that ARTs may result in increased costs per unit of electrical output compared to utility scale generation projects, these costs are justified by the economic and environmental advantages from encouraging in-state distributed small-scale generation.
  - Other advantages of small renewable are not listed by the Task Force – relative ease and quickness of citing, transmission and distribution benefits of projects
- **DBA** – Somewhat unrelated comment given – demand side management and conservation should play a role in reaching RPS requirements.
- **BioSol** – Other factors should be considered – need new framework and values for energy production, want projects which have a positive, sustaining impact on communities

e. What role, if any, should small, customer-owned renewables play in helping utilities reduce greenhouse gases? Should utilities seek to reduce greenhouse gases at the lowest possible price, or should other factors be considered? What ART structure would best incentivize the reduction of greenhouse gases?

- **WUA** – Responded generally to this question, stating that the ART policy must follow the guidelines listed in the Task Force report.
- **DBA** – Responded generally to this question, stating that the ART policy must follow the guidelines listed in the Task Force report.
- **BioSol** – Best structure – incorporate price of externalities into cost of fuel (full cost pricing). Should have utilities pay a tax to cover the cost of externalities which is used to fund renewable energy projects.
- **GHDinc** –
  - Utilities should support renewable energy with adequate tariff rates which can easily be explained and utilized by lending institutions for cash flow purposes for AD system owners
  - RECs should be passed onto utilities to meet RPS requirements
  - CCs should be kept by owner – utilities do not need CCs so they generally won't offer fair price

6. What are desirable and appropriate design structures?

a. Should the ART directly target new capacity and new generation?

- **WUA** – Example given – focus on new capacity and generation must be balanced against the costs and risks to ratepayers, reliability of electric distribution system, etc.
- **BioSol** – ART should target new generation
- **GHDinc** – ART should include existing generation, current AD owners were the innovators and risk takers and should not be penalized for pioneering spirit. Many improvements have also occurred since some early pioneers installed systems – many systems will require substantial upgrades

b. How can ART payment levels be structured such that producers are not undercompensated or overcompensated over the duration of the contract?

- **WUA** – Compensation necessary to promote customer-owned renewable generation will differ based on objectives of individual customers. Value may be derived by some producers: (1) for their business (e.g. green branding), (2) to reduce energy cost volatility, (3) combination of individual or business objectives. Appropriate pricing will also be different whether ART is being used to meet RPS – cost-effective energy that will be paid for by all customers - or supply energy for utility green pricing program – supply energy for smaller group of customers that volunteer to pay more.
- **FCPC** – Tariffs should provide for full recovery of all capital costs, and after the duration of the contract price paid for energy should revert to avoided cost
- **BioSol** –
    - Tricky to ensure producers are properly compensated
    - Could help producer by including inflation adjustment or other price adjusting mechanism
- **GHDinc** – Cow Power system of pricing fairest pricing – day ahead plus fixed price premium. Price premium workable pricing solution and easy to utilize to obtain project financing.

c. Is long-term forecasting of renewable technology economics reliable enough to offer price guarantees? How should long-term forecasting affect ART structures?

- **WUA** – Did not address question specifically
- **BioSol** – Yes - Renewables are more predictable than fossil fuel counterparts because the fuel is seldom part of the risk or cost to operate the system

d. How should the availability of financial incentives for renewable technologies through the Focus on Energy program and voluntary utility programs affect decisions regarding ART payment amounts?

- **WUA** – Did not address question specifically
- **FCPC** – Task Force electric generation work group determined that other financial incentives such as tax credits and those from Focus on Energy should not be considered in setting ARTs since they are not always available or applicable and can change over time
- **BioSol** - Federal and State incentives should have no impact on ART payments.
- **GHDinc** – Can be used as in Vermont to pay for utility interconnection costs and provide 3-phase system upgrades where they are needed. Interconnection costs are rapidly escalating in Wisconsin – area of concern Commission should consider studying.

7. Other Policy Questions

a. Are there any legal issues which constrain the Commission's ability to develop and implement an ART policy?

- **WUA**
    - Commission should determine extent to which it will modify findings and conclusions from past orders. Orders include these relevant requirements: "(1) electric utility purchases be priced at varying full avoided short- and long-term marginal energy costs, (2) utilities provide compensation for 75% of the capacity value for the customer-owned generation, and (3) utilities make net metering available for customer-owned generation rated at 20kW or less." Emphasize Commission's 1983 Generic Order on avoided cost calculations.
    - FERC rules governing utility purchases from qualifying facilities (QF) under PURPA – these rules have own directives concerning interconnections and avoided cost calculations.
    - PURPA amendments under federal Energy Policy Act of 2005, specifically relating to elimination of requirement that a utility enter into mandatory purchase agreement with QF after non-discriminatory access to wholesale market has been provided.
    - Energy Policy Act of 2005 – Commission may not require an electric utility to purchase renewable energy if utility is in compliance with RPS.

b. What effects might ARTs have on jobs, fossil fuel imports, and agriculture?

- **WUA** – Did not address question specifically

- **FCPC** – Properly designed – positive impact. Will allow WI to maximize use of its own wind, agricultural biomass, forestry biomass, solar and other renewable resources.
- **BioSol** – ARTs will have a positive impact on jobs, will result in decreased fossil fuel imports, and in general will be very good for Wisconsin residents and farmers – money stays in the state.
- **GHDinc** – Profound effect on jobs
    - AD system utilize WI labor, contractors, etc.
    - Replace purchased fossil fuels
    - Multifaceted positive impacts on agriculture
    - Lowers waste disposal costs for food processing industries

c. Should utilities allow customers to voluntarily choose to purchase electricity generated from a specific technology (e.g., solar PV)? Docket 5-EI- 148

- **WUA** – Many utilities already have green pricing programs, but not WI utilities and few in the country have gone one step further to allow customers to purchase energy from a specific technology. Market research needed to determine plausibility.
- **BioSol** – Adds complication

ART Design Issues

8. Overall Tariff Structure

a. Should ARTs offer a fixed price (e.g., 10$/kWh), a fixed premium (e.g., 4$/kWh above the Locational Marginal Price), a hybrid of the two structures, or some other structure?

- **FCPC** – ARTs should take into account LMPs to account for system benefits based on the location of the small renewable resource. In general probably preferable to have price fixed over time to remove pricing risks that many small renewable developers may not be as well suited to address.
- **DBA** –
    - Should offer a fixed price that escalates with inflation
    - Financing challenges for contracts with floating prices because of localized nature of electricity markets
- **BioSol** – Keep the structure simple, fixed versus premium doesn't matter as long as builder can recoup his investment along with a reasonable profit.

b. How might an ART be designed to incorporate components of both a fixed price structure and a fixed premium structure?

- **DBA** – Not recommended

c. Should customers be able to choose between a fixed rate and a fixed premium when signing an ART contract

- **DBA** – Utilities are in a better position to answer this question

9. Program Size Limitations

a. Should the Commission limit the total program size of all ART offerings for the state as a whole, for individual utilities, and/or for specific technologies? If so, why?

- **FCPC** – To the extent that any price differential between small-scale generation and utility-scale generation are not anticipated to cause significant cost impacts for WI ratepayers – Commission should likely avoid overall size limitations.
- **DBA** – No – additional limitations will only serve to curb investment
- **BioSol** – No – basically don't limit it to maximize the use of renewables

b. If the Commission limits total program size, what should the basis be for such limits? Should limits on ARTs be based on participation levels, installed capacity, actual generation, RPS obligations, costs, or something else? Should limits on ARTs be fixed amounts or proportional to total capacity, generation, costs, etc.?

- **FCPC** –
    - The program size limit should be based on the cost to WI ratepayers

    - For specific expensive technologies like solar PV, likely makes sense to place some limitations on participation levels to keep costs reasonable
- **DBA** –
    - Limit should be RPS targets
    - If limits are in place, should reflect should reflect a truly-limiting metric – such as limits of the grid or utility funding available to pay premium
    - If certain types of renewable are to be promoted over others, pricing differentials and/or ‘adders’ should be used rather than limits to promote technology

c. If program size limits are imposed, should enrollment be on a "first come, first served" basis or based on some other criteria?

- **FCPC** – If size limits are imposed, it likely makes sense to provide greater access to ARTs to local communities, which are generally required to share the financial benefits of tariffs with their residents, members and users.
- **DBA** – “First come, first served” would work if there was a fair announcement process for enrollment, basically don’t give speculators prior knowledge.

10. Covered Renewable Energy Technologies

a. Are there any specific technologies for which all utilities should be required to offer an ART?

- **FCPC** – The technologies listed in problem three should be included since they are all technologies demonstrated in Wisconsin.
- **DBA** –
    - Renewables should be defined to include all pertinent technologies
    - Technologies under ART should be uniform across state to prevent inequities

b. On what basis should the Commission decide whether it is appropriate to offer an ART for a given technology?

- **DBA** –
    - Use best practices in European and Ontario ARTs, which provide strong definitions of what technologies should be included in ARTs
    - Commission should follow precedent of technologies: Small hydro, solar pv, biogas, biomass, and landfill gas.
- **BioSol** – Most important thing is that ART does not value one technology unfairly over another

c. Should the ART be technology-specific or apply to a generic definition of renewables?

- **DBA** – Art should apply to a generic definition of renewable
- **BioSol** – Generic definition that gives user and installer the most option is preferable

11. Individual Project Size Limitations

a. What project size limits, if any, are appropriate for each technology, and why?

- **FCPC** –
    - Smaller projects need proportionally more incentives than larger projects because – bigger sources of power typically have lower costs of capacity and energy, large scale projects can attract investor interest much more easily, smaller projects require more incentives to make them fundable.
    - Key policy question – “free ridership.” Should the State incentivize larger projects that may not need it or need relatively small incentives?
    - In Tribe’s view – all projects should receive sliding scale of incentives with more incentives provided for small projects and less for larger projects
- **DBA** –
    - Typical farm biogas – 1MW or less
    - Larger farm systems – 2MW – 10MW if they utilize off-farm substrates
    - Size limits may be different, but ART price level should reflect size and type of installation

b. Should project size limits be uniform across utilities?

- **DBA** – If project size limits are in place, they should be uniform across utilities
- **BioSol** – There should be no size limits

12. Contract Duration

a. Should utilities offer the same duration for all ART contracts regardless of the technology?

- **FCPC** –
  - As mentioned above – key principle of task force report is that tariff should be fixed over a period of time that allows for a full recovery of all capital costs
  - Time frame should therefore be based on expected life of the facility and the time period that would allow for full cost recovery plus a utility return, while still resulting in a reasonable cost for the energy purchased.
- **DBA** – **Yes**
- **BioSol** - **Yes**

b. What is the optimum duration for ART contracts and why?

- **DBA** –
  - 20 years – would provide more secure returns and alleviate risk to a project lender
  - ART should be tied to an inflationary adjustment factor, such as GDP Price Deflator published by Department of Commerce
  - Europe and Canada have shown that it is virtually impossible to demonstrate satisfactory returns to project financiers on contracts less than 20 years

WUA Response to Questions 8-12 – ART design components will need to be tailored specifically to overarching policy objective – policy objective examples are: to help meet RPS mandate, achieve certain level of small customer-owned renewable energy projects, or to supply a local distributed resource for voluntary green energy program. **Two general principles are critical**: (1) Keep ART design simple and easy for potential customer participants to understand, (2) Use care in designing programs to minimize opportunities for manipulation or unintended consequences.

13. Cost Recovery

a. Why and under what circumstances might it be appropriate for ART costs to be recovered through ordinary rates paid by all customers or a class of customers? For purposes of answering this question, assume "ART costs" means all costs arising from the administration of the ART. Docket 5-EI- 148

- **WUA** – If ART is a tool used to help a utility meet its RPS or other mandated renewable energy requirements. RPS applies to a utility's overall supply mix and costs and benefits accrue to all customers.
- **FCPC** –
  - ART costs (i.e. cost arising from administration of the art) should be recovered from all customers regardless of whether the energy is used to meet the RPS or included as part of voluntary sales
  - Costs should be recovered from all customers because of State's strong interest in promoting local, renewable energy, which benefits all entities in Wisconsin regardless of whether they purchase voluntary renewable energy.
- **DBA** – Wisconsin Legislature should be tasked with publically debating any fees or increases because not all customers have the same ability to absorb significant utility rate increases

b. Why and under what circumstances might it be appropriate for ART costs to be recovered through a utility's voluntary renewable energy program?

- **WUA** – When the ART is a tool used to supply renewable energy to its voluntary renewable energy program.
- **DBA** – Voluntary program will see progressive ratepayers (i.e. voluntary ratepayers) paying a larger portion of ART costs, which makes sense from a market supply/demand standpoint.

c. Should utilities have the discretion to choose the best means of cost recovery for each specific tariff, or should the Commission seek a uniform approach?

- **WUA** – Wisconsin law allows for double counting, energy used to supply a voluntary program can simultaneously be used to meet a mandate. 3rd party certification does not allow this and no utility programs are currently doing so. However, current provisions in Wisconsin law make it appropriate for the Commission to allow utilities to choose the best means of cost recovery as RPS requirements and voluntary programs evolve over time.

14. Renewable and Environmental Attributes

a. Should ownership of associated renewable and environmental attributes (such as Renewable Energy Credits or greenhouse gas offsets) be consistent across all ARTs in Wisconsin?

- **WUA** –
  - "To clarify, it is assumed the attributes referred to in this question exclude Renewable Resource Credits (RECs) which are unique to Wisconsin and can only be owned and traded by Wisconsin electric providers."
  - "If the entity purchasing the energy thru an ART is paying a premium for the energy over that of a standard energy tariff, then the attribute should transfer to the purchaser."
  - "If the ART is being used as a primary tool or instrument to incentivize renewable energy development and meet renewable energy targets in lieu of an RPS, then yes, attributes should be treated consistently across all ARTs in Wisconsin."
  - If ARTs are implemented as a secondary tool for renewable energy development then consistency may be of less importance"
- **FCPC** –
  - Due to importance of developing small in-state renewable energy generation regardless of whether it is used to meet the RPS or not – may be beneficial to provide generators option for small generators to either sell or keep the RECs.
  - May be appropriate to have a mechanism that allows utilities to require that the community adjust ARTs to require that the RECs be sold with the energy to the utility
- **DBA** –
  - The REC portion of the benefits should become title of the utilities
  - Non-electricity environmental attributes should not go to the utilities – for example some biogas plants create a natural replacement for chemical fertilizer, offsetting GHGs from fertilizer use and production, this attribute should not be property of the utility. This fertilizer creation process is distinct from electricity generation process.

b. Should ARTs be established with separate prices depending on which party owns the renewable and environmental attributes?

- **WUA –**
  - If the purchaser does not own the attributes, this should be reflected in the price.
  - Currently, all WI electric utilities offer a standard energy purchase tariff which establishes a price the utility will pay for electricity generated within their service territory – this price does not include purchase of the renewable attributes.
  - Experimental ARTs which have been implemented offer a price premium over utility's standard energy purchase tariff which pays for transfer of ownership of associated renewable and environmental attributes.
  - An ART which does not transfer ownership of renewable and environmental attributes would be the same as a standard energy purchase tariff, and would therefore not offer an incentive for renewable development.
- **FCPC** – Participants should be paid appropriate amount less if they retain the RECs

15. Basis for Setting Tariff Price

a. For a given technology, should there be any differentiation in ART prices based on design characteristics (e.g., vertical versus horizontal axis wind turbines), fuel source (e.g., biomass crops versus wood waste), or location (e.g., terrestrial versus offshore wind)?

- **WUA** –
  - "ART pricing should support the strategic purpose and balance of the program."
  - Pricing should consider complexity of administration for the ART program – complex billing will increase costs of billing administration.
  - Separate prices for design characteristics can be helpful if goal is to encourage various types of renewable generation resources.
  - A more standardized approach (standard price) will encourage the most economically efficient resource to surface as the preferred technology.
- **DBA** –
  - It will be difficult to create tariff detailed enough to handle all reasonable variations, also will add cost and complexity to the process
  - Should only be differentiation if specific technologies, fuel sources, or locations are highly priced by state or utilities and incentives are necessary to ensure these projects happen.

b. For a given technology, should ART prices decline as project size increases? If so, should size bands be created or should the price decline in linear proportion to size? How might the Commission decide on appropriate size bands?

- **WUA** –
  - If price is a premium representing a value for renewable attributes, then price differentiation by size may be less of a concern.
  - If price level is established to provide reasonable payback for renewable generation system – then it would be appropriate to establish price levels to reflect differentiation of price due to economies of scale.
- **DBA** –
  - Yes, ART prices should decline as project size increases
  - Prices should decline in linear proportion to size, more efficient from a developer standpoint

c. Should ART payment levels include any form of a capacity payment in addition to energy payments? Does your answer vary by technology? Could an auction or tender-based system for renewable capacity payments (similar to Forward Capacity Markets) help increase economic efficiency and/or reduce risk on behalf of the investor?

- **WUA** –
  - Dependent on how ART pricing is designed.
  - If pricing is designed to compensate based on a break-even level for the generation investment, then energy payments should be established to recover both fixed and variable cost.
  - "To the extent that the facility can be used to meet the utility's capacity obligations, the utility should be entitled to that capacity without further payment."
- **DBA** –
  - Payment should reflect actual generation
  - Simpler and more transparent the program, the more traction it will gain with project financiers and project proponents
  - Auction and other systems for payments favor only the largest developers which are capable of providing resources to manage this process, and are not recommended

d. Should ART prices be set at a level such that a typical participating customer will earn a positive return on their investment in renewable energy? If so, what might be an appropriate return?

- **WUA** –
  - Unlikely utilities would receive proposals under ART that did not offer full cost recovery.
  - ART that requires long-term contract at a known price is a low risk investment for most developers, appropriate return is discussed further in answer to question 6.
- **DBA** –

- Appropriate returns depend on: prevailing market conditions during period when ART contracts are signed, security of ART program and its guarantors, etc.
- Most effective way to determine appropriate ART price level – understand all the factors influencing prices projects and individual project owners risk/reward criteria.

e. Should utilities offer separate prices for on-peak and off-peak generation or a single blended ART price? Should the utility or the customer be allowed to decide on their preferred approach?

- **WUA** –
  - On-peak and off-peak pricing provides an incentive for customers to efficiently operate their renewable generation and encourages maintenance down time during off peak periods.
  - Technology dependent though – example: for solar this is not critical since the technology has a predictable time of day output.
- **DBA** – Yes, utilities should offer separate on-peak and off-peak prices to encourage on-peak generation

f. Should ART contracts include an automatic adjustment in the price based on inflation?

- **WUA** –
  - **No.** Under most ART proposals – pricing designed to enhance the economic break-even for an ART generation resource based on a **specific investment scenario**.
  - Furthermore – regulatory limitations make it problematic to implement automatic rate level adjustments. More appropriate to regulate pricing levels within context of regulatory proceeding.
- **DBA** –
  - **Yes –** ART contracts should be keyed to adjustments such as inflationary pressure.
  - Inflation will affect project costs in real terms, each year, particularly where the operating and maintenance cost are high as with biogas.

g. If the Commission does not require utilities to offer uniform contract duration for all ARTs, should utilities offer different prices for different contract durations?

- **WUA** – Should be evaluated in broader scope of structure of the specific ART program. ARTs should be uniformly designed with similar pricing methodologies for all utilities.
- **DBA** – It is not recommended that contract terms vary – if they do premiums should be paid on shorter term contracts to assist in finance ability.

h. If any fixed premium ARTs are established (rather than fixed cost ARTs), should the premium be over and above the Locational Marginal Price, or should it be tied to some other number? Since a fixed premium would result in a variable price, should there be a price cap or other measures to prevent unacceptable profits or losses?

- **WUA** –
  - Hourly LMP pricing is not currently used for standard retail parallel generation tariffs, so it does not seem to make sense to add this complication to ARTs.
  - "If ART program intends to provide incentive to investment in renewable resources, then the volatility of LMP prices will discourage investment and make it difficult for customers to find financing commitments for their ART resources."
  - Administration cost would significantly increase for hourly load reconciliation and would be less cost effective considering the size of ART generation resources.
  - Fixed premium art discussed in 8.
- **DBA** – Fixed cost arts are preferred because they provide known returns based on performance

i. Should ART prices be automatically reduced annually (or periodically) to reflect the maturation of technologies and the need for renewables to become cost competitive without price supports (digression)?

- **WUA** – **No.**
  - Seems appropriate to revisit pricing parameters as market costs and participation change.
  - Changes may mean – close existing ART options to subsequent installations, reduce pricing levels if technologies become more cost competitive.

    - Refer to 6 for related information.
- **DBA** – **Yes.**
    - ART prices should be reduced periodically for new contracts and projects to reflect maturation of technologies
    - Should not be reduced for existing projects though – where technologies were at an earlier point of maturity when capital expenditures were made

j. Are there any benefits to customers unrelated to electricity generation that should be reflected in the tariff prices?

- **WUA** –
    - Many ART tariffs developed to consider the cost of investment rather than reflecting generation output and renewable attributes value.
    - ARTs with fixed compensation levels per output unit establish increased pricing stability.
    - Basically, no -- prices will likely not be set based on benefits to customer.
- **DBA** – Biogas benefits:
    - More sustainable way to manage organic by-products, e.g. food scraps
    - Additional GHG reduction potential due to methane destruction of manure and organic by-products
    - Nutrient management for farms – as, in many cases, excess farm nutrients are converted into natural fertilizer
    - Reduction of odor, weed seeds, and pathogens
    - Increased stewardship of water resources
    - Job creation, particularly in rural areas

- **FCPC** – General comments regarding setting tariff prices
    - Pricing structure should follow the principles set forth in the Task Force Final Report
    - Would generally call for neither a price increase over time based on inflation (except potentially for operating and maintenance costs)
    - Nor a decrease in price over time
    - Price should reflect the full array of benefits that a small generation project provides for the system – including capacity benefits
    - Pricing should allow a return on investment comparable to the utilities rate of return

16. Other

a. Are there any other ART design considerations that you feel the Commission should consider?