Appendix D: Power Generation

Page

D.1 Summary: Electricity Supply for Greensburg, Kansas, as of December 2007

Lynn Billman
National Renewable Energy Laboratory

D.1.1 Pre-Tornado Electricity Supply

The City of Greensburg acts as a municipal utility which provides customers in Greensburg with electricity, water, sewer, and trash services. The City owned the distribution lines within the community before they were largely destroyed. The City bought electricity under a ten-year, co-generation agreement with Sunflower Electric Power Corporation, a consumer-owned, nonprofit generation and transmission service provider. Sunflower is owned and operated by six rural electric distribution cooperatives; the cooperative serving Greensburg is Southern Pioneer. These six rural electric coops recently formed a coalition, Mid-Kansas Electric Company, LLC, to buy the assets of Aquila's Kansas Electric Network.

The City also owned and operated a power plant and substation with five Fairbanks dual-fuel (natural gas and diesel) generators. At Sunflower's notification, city operators would fire up the generators to meet peak loads, generally summer air conditioning.

The City had approximately 1,000 customers at the time of the tornado. In total, city customers used 15.6 million kWh of electricity in 2005 and 14.0 million kWh in 2006. The average load was 2.7 MW; peak load (generally summer) was 4.3 MW. The City charged the customers 12 ¢/kWh. This covered expenses approximately as follows: 4 ¢/kWh for wholesale electricity from Sunflower; 2 ¢/kWh fuel charges; 4 ¢/kWh for city-owned power plant; and 2 ¢/kWh for other city expenses.

D.1.2 Post-Tornado Electricity Supply

Immediately following the tornado of May 4, 2007, FEMA provided emergency generators and other support. Sunflower assisted in providing limited power very quickly as well.

The first action of the City was to replace the distribution lines, a $10M project. FEMA provided 75% ($7.5M), the state 10%, and the City 15%. The electricity distribution system was completed about December 1, 2007.

In July 2007, the city entered into a Memorandum of Understanding (MOU) with Sunflower. The key provisions of this MOU are as follows:

- When the distribution lines are complete, Southern Pioneer will purchase the City's electrical system.
- The City will enter into a long-term franchise agreement for Southern to provide electricity to the citizens at retail rates, proposed verbally to the City as 9 ¢/kWh.

The rates are regulated by the Kansas Corporation Commission. The higher the franchise percentage the City wants, the higher the rates.

This arrangement is attractive to the City because it would relieve the City of the responsibility of managing an electrical utility, and the cash received for the distribution assets would help the City pay off some outstanding debts. However, the City would no longer act as a municipal electric utility, and would lose the ability to add or change generating sources such as wind or solar.

Greensburg's contract with Sunflower expired Oct 31, 2007. On November 1, 2007, the City entered into a 180-day contract for electricity, which expires April 2008. Under this contract, Mid-Kansas provides electricity from its generating sources or from market sources (at Mid-Kansas sole discretion) to the Kansas Municipal Electric Association (a cooperative of 15 cities with a load of about 30 MW) for resale to the City. The price to Greensburg is Mid-Kansas' cost plus 10%, plus a monthly demand charge of $3.00 per kW, based on the peak requirement integrated on a 15-minute basis.

D.2 Community Wind Options

Trudy Forsyth
National Renewable Energy Laboratory

Tom Wind
Wind Utility Consulting

Community Wind Options

Trudy Forsyth (NREL) & **Tom Wind** (Wind Utility Consulting)

NREL National Renewable Energy Laboratory

Overview

- Definition of community wind
- Where have community wind installations occurred
- Where is policy driving this market
- What specific policies are moving the market
- What are the successful economic models turbine
- Turbine costs/availability (?)
- Options for Greensburg
- Lists of more sources of information
- Contact information

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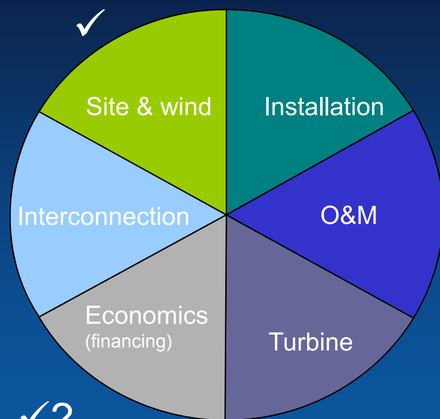
Key Issues of Community Wind project

✓

✓?



✓?

CREB??
✓USDA?

Electrons
Green Tags

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Defining “Community Wind”

- **Locally Owned:** One or more members of local community have a direct financial stake in the project, other than through land lease or tax revenue
- **Utility-Scale Turbines:** 50 kW threshold for new turbine projects and refurbished turbine projects
- **On Either Side of Meter:** Power consumed on site or sold to unrelated party (or both)

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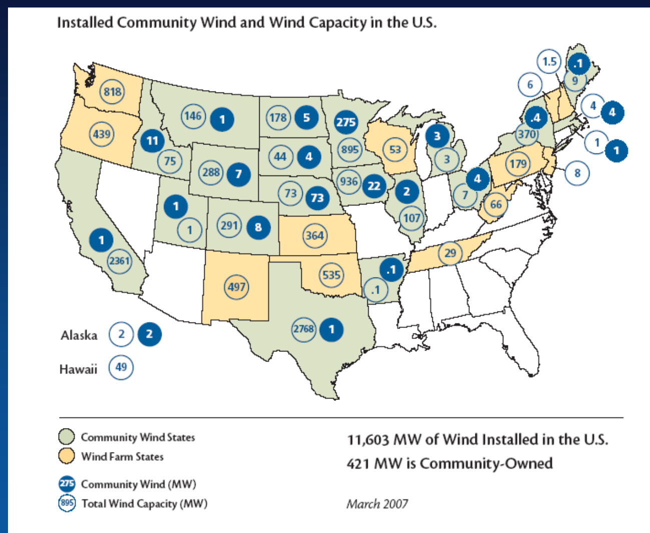
Community Wind in the United States



In 2000, 80% of installed turbines in EU are community wind

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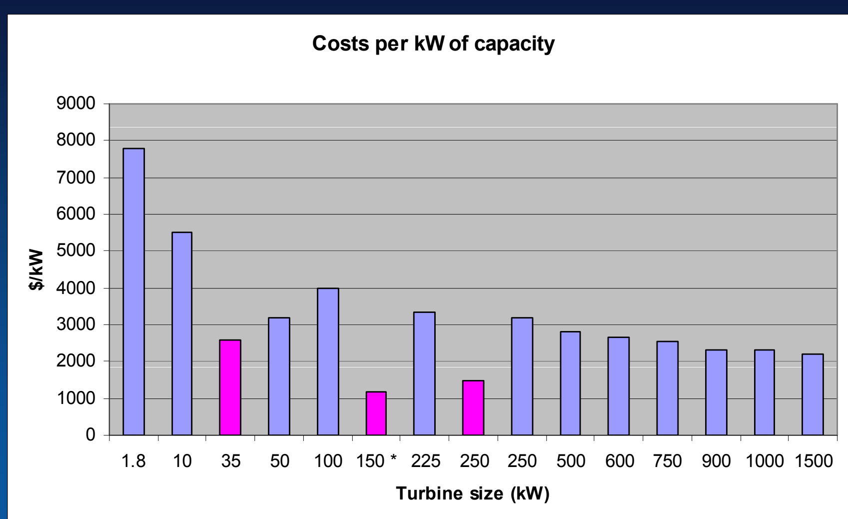
Turbine costs per kW



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The Major Challenge for This Project:
--- Wind turbine procurement ---

- It is a Seller's Market!
- Most major manufacturers have no wind turbines available for 2008 or 2009
  - Large wind farm developers have purchased most wind turbines
  - Earliest delivery for major new projects may be in 2008
  - A few turbines become available as construction schedules slip
  - Three years ago, delivery time was 20-25 weeks
- Manufacturers favor larger orders rather than smaller orders since they make more money
  - In many cases, no manufacturers may even bid on supplying a single wind turbine
- To get a turbine in the near future you may have to work through a larger developer

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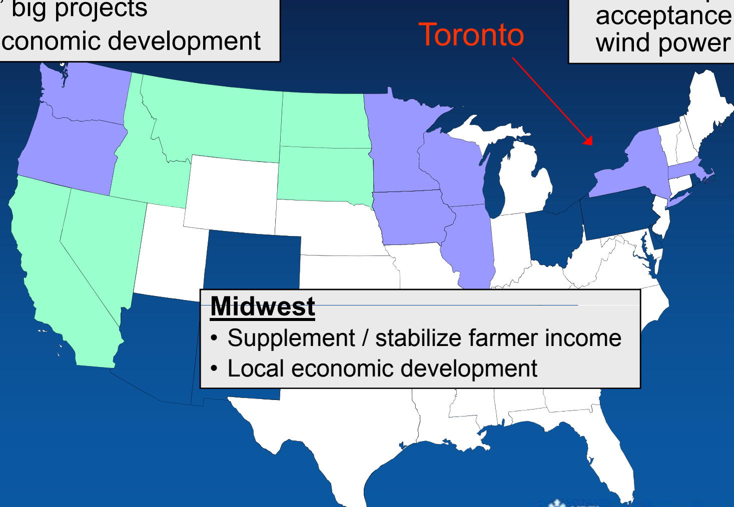
2004 – Spanning the Country

Northwest
- "Fill the valleys" between "lumpy" big projects
- Local economic development

Northeast
- Increase public acceptance of wind power



Midwest
- Supplement / stabilize farmer income
- Local economic development

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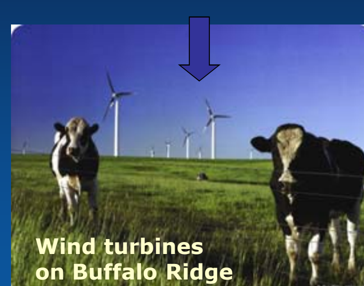
How did Minnesota become a Community Wind leader?

- Xcel Energy's wind mandate (1994)
- Minnesota's 10-year production incentive of 1.5¢/kWh (1997)
- Minnesota's renewable energy objective (2001)
- Xcel Energy's small wind tariff and standardized power purchase agreement (2001)
- Xcel Energy's Renewable Development Fund (implemented in 2001)
- USDA Farm Bill, Energy Title Grants (2002)
- C-BED Tariff (2005 and 2007)

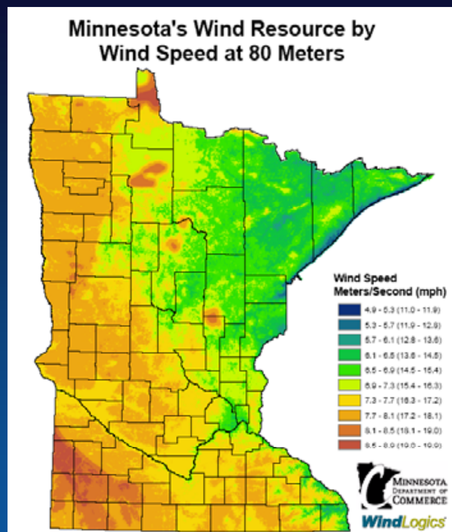
Successful incentives address financing issues, provide access to capital, equipment, and/or strengthen the market for community wind.

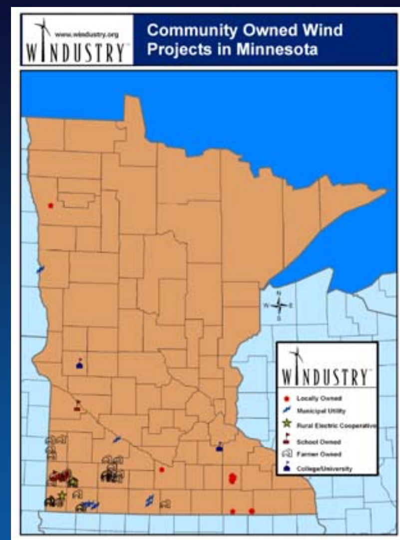
Xcel Energy Wind Requirement

- 1994
  - Legislature requires that Minnesota's largest utility acquire 425 MW
- 1999
  - expanded to 825 MW
- 2003
  - expanded to 1,125 MW
- 2007
  - Expanded to 30% by 2020



This created a market for wind development in Minnesota!!!





Minnesota has made local ownership a priority!

WINDUSTRY

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Illinois

Bureau Valley School District (660 kW, on-site)
- $20,000 grant for feasibility study (ILCECF)
- $375,000 construction grant (ILCECF)
- In final permitting stages

Illinois Rural Electric Cooperative (1.65 MW, supply mix)
- $175,000 up-front 10-year REC purchase (ILCECF)
- $250,000 grant (RERP)
- $438,544 grant (USDA)
- Broke ground in May 2004

Illinois State University (1.5 MW, seeking power purchaser)
- $500,000 grant (ILCECF), dependent on other grants

3-Year Statewide Wind Monitoring Program (ILCECF)
- Targets sites suitable for community-scale turbines

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Illinois Rural Electric Cooperative

Pike County, Illinois

- *Size:* 1.65 MW turbine
- *Date:* Spring 2005 ribbon cutting for one.
- *Inspiration:* IL wind maps showed some of the best wind in the state to be in IREC territory.
- *Output:* Turbine generates about 4% of IREC's power needs, close to the 5% limit in wholesale power contract.
- *Financing:* Project supported by 3 grants
  - USDA
    IL State grant
    IL Clean Energy Foundation

IREC Engineering Manager and project leader Sean Middleton.

WINDUSTRY

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How do state policies stack up?

Feed-In Tariffs (MN): Ideal for community wind

RPS (various states): Philosophically at odds with feed-in tariffs, community wind may require "carve out" (like in Minnesota)

Cash Production Incentives (MN): Accessible (tax liability not required, low transaction costs), and work well with the PTC (no haircut)

Infrastructure Development (WI, MA, OR): Reduces transaction costs of development, which can otherwise kill a community wind project

Grants (IL): Structure so that do not reduce value of PTC

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CREB Overview

- Clean Renewable Energy Bonds (CREBs) were created by Energy Policy Act of 2005 (Baucus & Grassley)
- Provide gov't entities with ability to obtain interest-free financing for renewable energy projects by providing investors with federal tax credit in lieu of interest payments
- 2006 CREBs were authorized for $800M through FY07:
  - $500M: Cities, Counties, Tribes
  - $300M: Rural Electric Co-ops
- House proposal for 2007 $2B
  - 60% municipalities
  - 40% Rural Electric Co-ops
- Allocations made from smallest to largest (pyramid)
- CREBs are an excellent funding vehicle for county/city/tribally-owned renewable energy projects

On-Site *(Customer Side of Meter)*

A large electricity customer installs a utility-scale wind turbine to supply on-site power and thereby displace power purchased from the utility.

Examples: Iowa schools (e.g., Spirit Lake)

Strengths:

- Potential to offset retail (rather than earn wholesale) rates

Weaknesses:

- Sites with both large enough load *and* good wind are rare
- Net metering capacity limits usually well below nameplate capacity of modern utility-scale wind turbines
- Large loads typically face *demand* (and *standby*) charges
- PTC (or REPI) not available for power consumed on site
- Electric bill savings are taxable income (to a taxable owner)

Multiple Local Owner

Local investors jointly own off-site, utility-scale wind turbine(s), and sell power to a utility.

Examples: Minwind I & II

Strengths:

- Straightforward, no corporate equity involved, purely local
- Don't have to wait 10 years for serious cash

Weaknesses:

- To maximize return, need investors with passive income
- Project shares may need to be registered as "securities"
- Relatively high organizational burden
- Must secure a power purchase agreement

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Minnesota-Style Flip

Landowner with insufficient tax liability partners with tax-motivated corporate investor to own utility-scale wind turbine(s) and sell power to the utility. Initial interests in project LLC (99% corporate/1% local) "flip" after 10 years.

Examples: Dan Juhl projects

Strengths:

- Innovative way to ensure capture of PTC and improve project economics

Weaknesses:

- Local makes above-normal returns (sub-optimal)
- Local return may be heavily back-loaded (after year 10)
- Need to engage corporate equity partner
- Must secure a power purchase agreement

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Town-Owned *(Utility Side of Meter)*

A municipality (but *not* a municipal utility) owns a utility-scale wind turbine and sells power to a utility.

Examples: Northfield, MN and Massachusetts (both planned)

Strengths:

- No land lease or property tax expense, municipal debt(?)

Weaknesses:

- ? May not be legal…
- “Private use” issues may restrict ability to finance project using tax-exempt municipal debt
- Economics depend heavily on availability of REPI or CBED
- Relatively weak opportunities for local citizen participation
- Must secure a power purchase agreement

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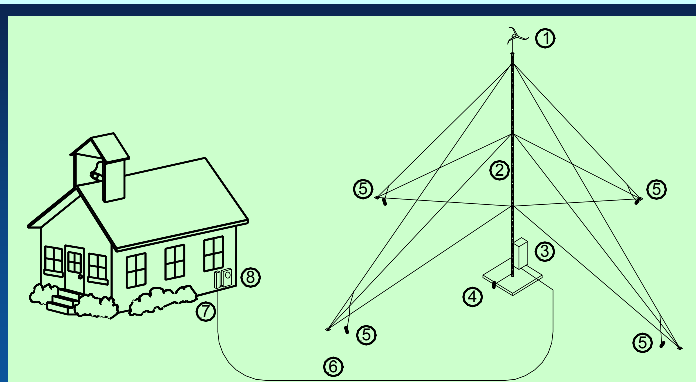
WIND POWERING AMERICA

Wind for School

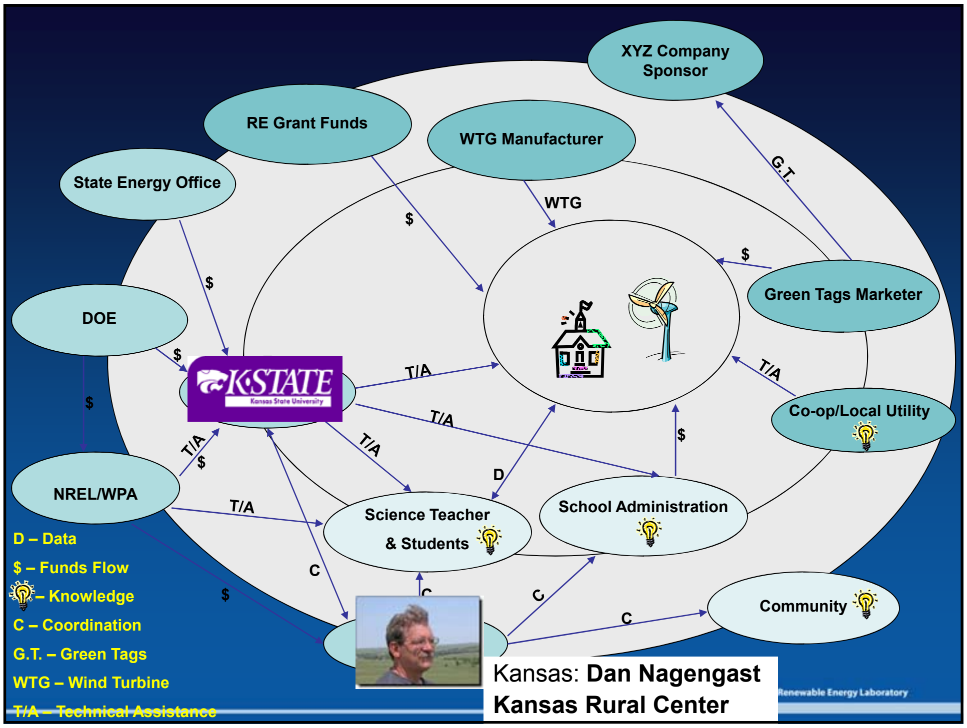
Initially envision using a standard system package, but could branch out and provides a process for the use of larger or different systems.



SKYSTREAM 3.7™
www.skystreamenergy.com

Southwest Windpower
Renewable Energy Made Simple

NREL National Renewable Energy Laboratory



Options for Greensburg

- Piggyback model – buy turbines planned for future wind farm
  - Economy of scale for turbine costs, development, installation and O&M
- Town-owned or multiple local owners
- On-site Customer side of electric meter
  - To meet cost goals must be refurbished turbines
    - Buyer beware
      - Need to know turbine history
      - Need to know refurbishment process & track record
      - Need to know warranty & performance bonding

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Community Wind contacts

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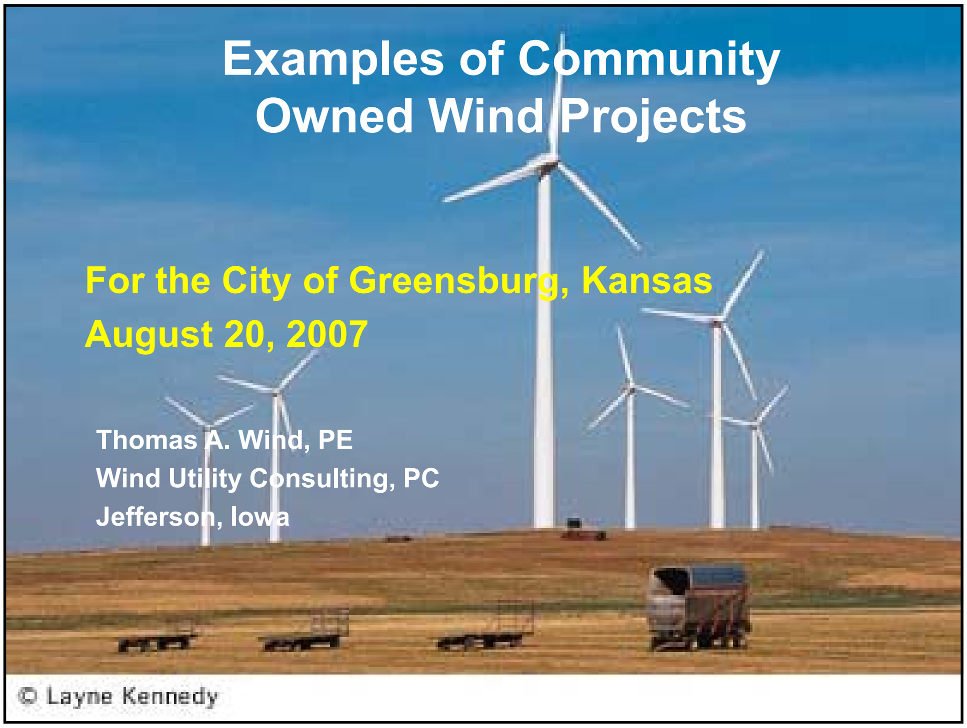
NREL National Renewable Energy Laboratory

D.3 Examples of Community-Owned Wind Projects

Tom Wind
Wind Utility Consulting



Examples I Will Discuss

- Municipal Utility-Owned Wind Turbines
  - Stuart Municipal Utilities
  - Lenox Municipal Utilities
  - Wall Lake Municipal Utilities
  - Southern MN Municipal Utilities
- Cooperative-Owned Wind Turbines
  - Illinois Rural Electric Cooperatives
- School-Owned Wind Turbines
  - Sentral Schools
  - Spirit Lake Schools
  - Eldora Schools
- Local Farmer-Owned Wind Turbines

2

Municipal Utility-Owned Wind Turbines

3

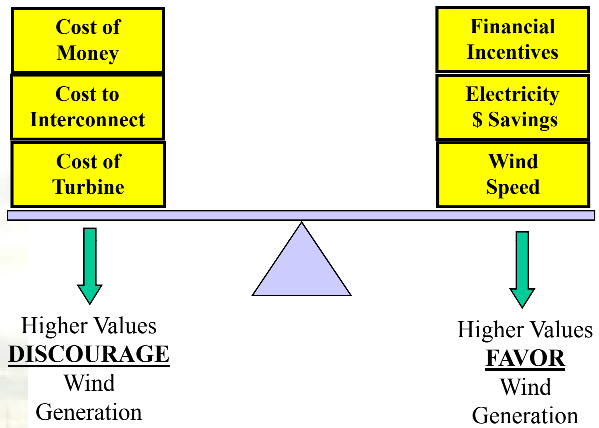
Wind Turbines for Consumer-Owned Utilities

School Children on a Field Trip to Visit Turbines Owned by Seven Iowa Municipal Utilities

- Small utilities owned by city residents or cooperative members
- Minnesota & Iowa have about 10 utilities that own a turbine installed locally
  - Another 100 utilities own a share of a larger wind farm
- In nearly all cases, wind power costs more for the first 10 to 15 years of the turbine's life, with savings occurring after that.
- Customer pressure is primary driver, with other drivers being environmental benefits and local champions
- Grants and CREBs very important

4

The Overall Economics of Wind Generation is Determined by a Balance of Factors



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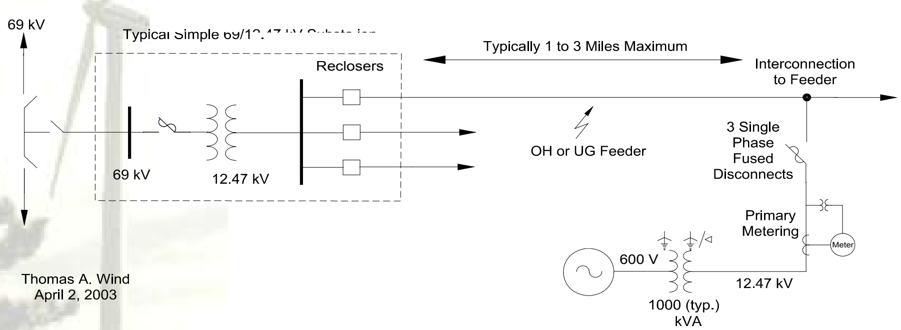
Single Line Diagram of Basic Interconnection



6

City of Moorhead, Minnesota

- Nearby Anemometer was used to estimate wind speed…. not very windy
- Initial study in 1997 indicated some potential savings, but not much
- Utility decided to proceed due to interest of customers and good cooperation of power supplier
- Installed 750 kW wind turbine in 1999, $667,000 + interconnection
- Sold all green power at 0.5¢ per kWh premium
- Installed second 750 kW wind turbine in 2001, $651,000 + interconnection
- Named wind turbines "Zephyr" and "Freedom"

From left: MPS Commissioner Bob Swenson, Pat and Marilyn Hecker, Tammy and Jeremy Kroke, MPS Commissioner Dave Kerssen, and MPS Commissioner Ken Norman.

7

Wall Lake, Iowa

- Initial preliminary study in late 1998 piqued interest
- More detailed studies in 2001 and 2002 showed slightly increased costs with a wind turbine, unless a grant was received
- Wall Lake received $250,000 CDBG grant
- Installed 660 kW wind turbine in 2003, costing about $750,000
- Levelized Long-term Cost is 3.6¢ without federal REPI payment
- Turbine provides 20% of town's energy needs
- This is a Big Deal for Wall Lake!

Lamar, Colorado

- *Owners:* Lamar Light & Power/Arkansas River Power Authority
- Lamar piggybacked on larger project to achieve economies of scale.
- *Size:* 5 turbines – 7.5 MW
  - 3 Lamar
  - 2 ARPA
- *Date:* Commissioned in 2004
- *Output:* About 15% of Lamar's annual energy needs
- *Financing:*
  - Revenue savings bonds,
  - Renewable energy credits,
  - Savings from piggybacking on top of 162MW Colorado Green Project

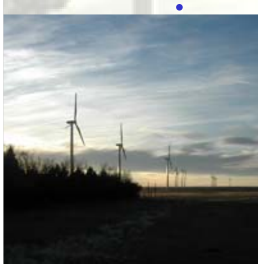
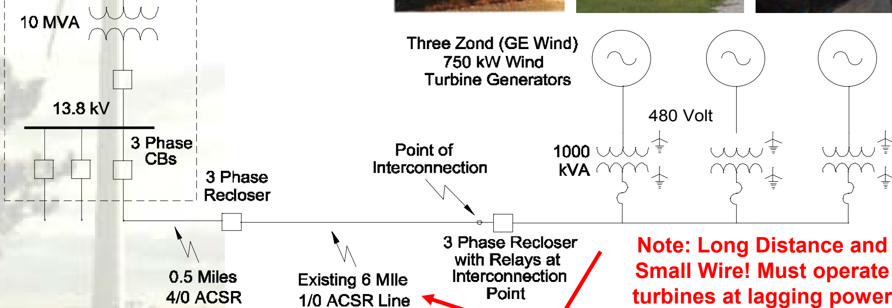


Photo Credit: Leon Sparks

Presentation: City of Lamar Light & Power and ARPA /Springfield Wind Project, Colorado Wind and Distributed Energy Conference, April 2004

9

Iowa Distributed Wind Generation Project With Three 750 kW Wind Turbines Near Algona, Iowa



Note: Long Distance and Small Wire! Must operate turbines at lagging power factor to keep voltage from getting too high.

10

Two Wind Turbines for the City of Fairmont, Minnesota

2 x 950 kW

11

City of Lenox, Iowa

- Original study in 2001 concluded no big savings
- Community supported project
- Added 750 kW wind turbine in late 2003 costing $950,000
- Received $400,000 Community Development Block Grant
- Power quality was important design issue due to weak rural system
- This is a Big Deal for Lenox!

"We're involved with wind energy in Lenox because it's good for the environment, the economy, and our state's and nation's energy independence. Supporting renewable energy and making Lenox a green city is a way we can ensure that what we're leaving to our children and grandchildren is a clean environment, a healthy economy, and a secure nation." Dave Ferris, Utility Manager

Stuart Municipal Utilities

- Small Iowa town (1700 people) in central Iowa
- Buys wholesale power from Cooperative G&T
- Has diesel generators to cover peak load
- Looked at long term savings in wholesale power costs
- Received CDBG grant
- Installed a 660 kW Vestas V47 wind turbine 300’ from Interstate Highway 80.

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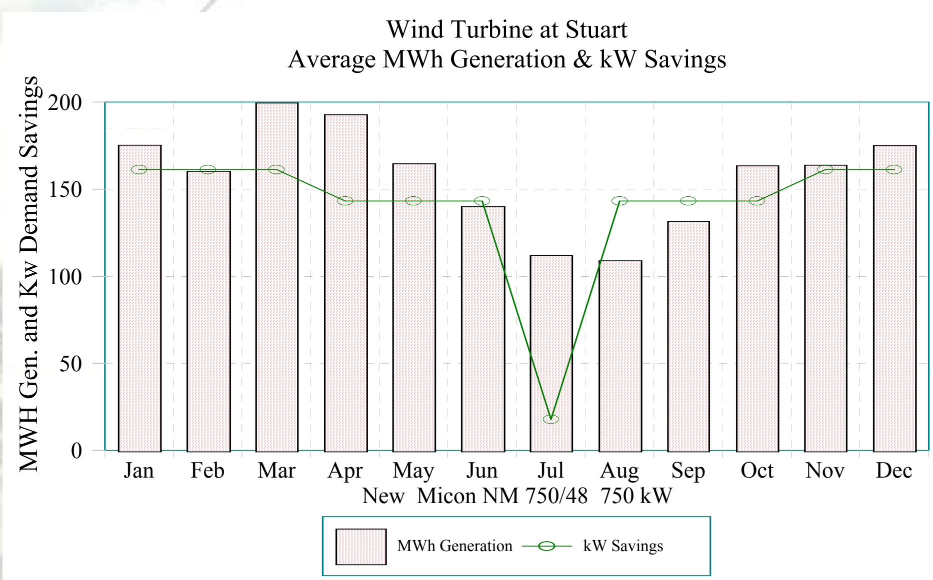
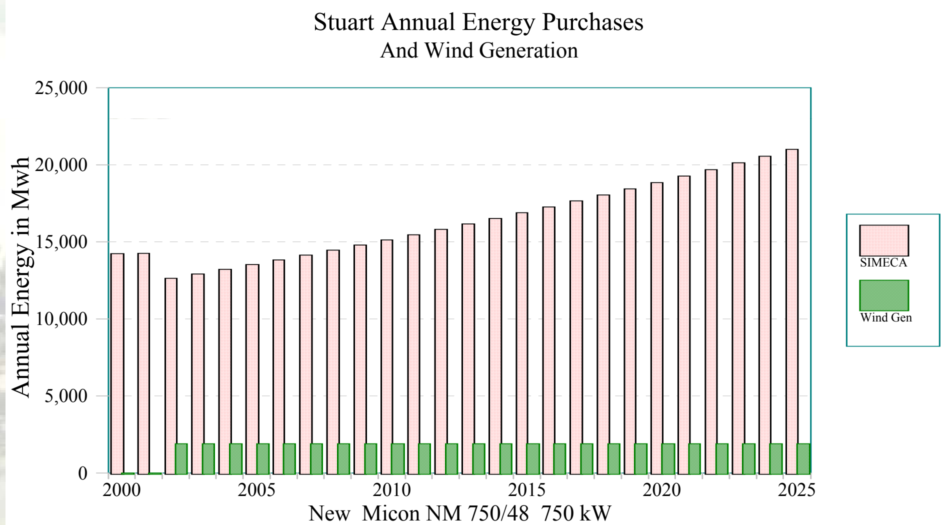
Monthly Energy & Capacity Value for a 750 kW Wind Turbine



Annual Energy Purchases & Wind Generation



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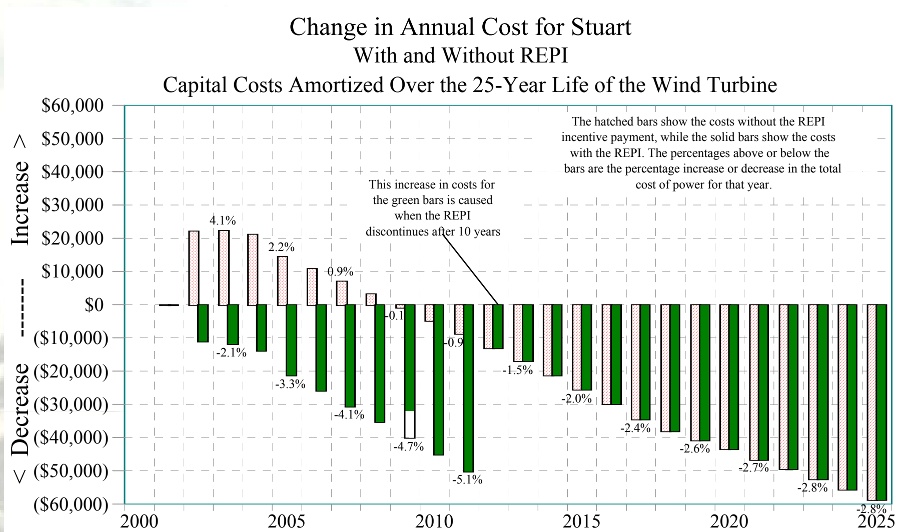
Preliminary Cash Flow Impact



Cost of wind generation was 3.7¢ with REPI, or 4.8 ¢ without REPI

16

Cooperative Utility-Owned Wind Turbines

17

Illinois & Iowa Cooperatives

- Illinois Rural Electric Cooperative installed a 1.65 MW Vestas V82 wind turbine in 2005
- Rural Electric Convenience Cooperative has ordered a 900 kW AWE direct drive wind turbine.
- Adams Electric Cooperative has also ordered a 900 kW AWE direct drive wind turbine.
- A few other Iowa rural electric distribution cooperatives are now considering installing single turbines near their distribution substation.
- Cooperative G&Ts often own or buy wind power from larger wind farms. Sunflower is an example.

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School-Owned Wind Turbines

19

Wind Turbines at Schools and Colleges

600 kW Wind Turbine for School at Forrest City Iowa

- Twelve Iowa schools and colleges in Iowa, and five in Minnesota have wind turbines. All projects are the result of two major factors:

1) Supportive Public Policies
   - Net Metering
   - Grants
   - Low cost financing
   - Tradable state tax credits
   - Green tags or RECs
   - Administrative and technical support from state
2) Determined local champions

Iowa Schools: Spirit Lake, Nevada, Sentral, Clay-Everly, Akron-Westfield, Forest City, Clarion, Eldora, Iowa Lakes Community College, Grinnell College
Minnesota Schools: Lac Qui Parle, Pipestone, Carleton College, St. Olaf, U of M at Morris

Sentral Schools at Fenton, Iowa

- Very small school system in NW Iowa
- Refurbished 65 kW WindMatic unit installed in 1994
- Generates about 40% of school's needs
- Went through period of time when they didn't get timely maintenance

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Wind Turbines at Spirit Lake Schools in Iowa

- 250 kW Wind Turbine installed in 1993 at a total cost of $239,000
- Loan repaid in 5 years
- Generates 350,000 kWh/year, saves school $25,000 per year

- 750 kW Wind Turbine cost $750,000 in 2001
- Loan paid off in 2007
- Generates 1,700,000 kWh/year
- After loan is repaid, savings from both turbines will be about $120,000/yr.

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Two Wind Turbines at School in Spirit Lake, Iowa

750 & 250 kW

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600 kW Turbine at School in Forest City, Iowa

24

Iowa Lakes Community College

- Small college in northern Iowa wanted to start wind technician training program
- Received federal budget earmark of $500,000 to help pay for a 1.65 MW Vestas V82 wind turbine and start up technician program.
- Considered connecting turbine to campus to reduce electricity purchases, but opted to sell all power to local municipal utility instead.

1650 kW Wind Turbine at Iowa Lakes Community College in 2005

25

Local Farmer-Owned Wind Turbines

26

Community Wind Economics Using Partnership Flip Model

- Many Community Wind projects use the Partnership Flip LLC structure (“Minnesota Flip”)
- This structure allows the project owners to take advantage of the federal income tax benefits provided to wind power
- Consumer-owned utilities cannot use federal income tax benefits since they are non-profit
- A three way partnership could possibly be formed between private owners, the city, and outside equity owners that can readily use the tax benefits.

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Farmer-Owned Wind Turbines

- Several 2 MW projects in SW Minnesota owned by individual landowners
- Developed by Dan Juhl on behalf of the farmers
- Typically two 900-950 kW Wind Turbines
- Enabled by Minnesota’s 1.5¢ per kWh incentive payment
- LLC formed with a tax investor that can use production tax credit and accelerated depreciation
  - Tax investor contributes up front capital to project

28

MinWind 1 & 2 Wind Farms

- Two Farmer-Owned Cooperatives in LuVerne, Minnesota owning four 950 kW wind turbines
- Farmers provide equity (40%) and borrow balance from local banks
- Farmes have some difficulty using federal tax credits
- Projects received state 1.5 ¢ incentive payment

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Summary

- There are many wind turbine projects that are owned by local communities, cooperatives, and individuals
- In most cases, there have been favorable state policies which have provided some incentives that enabled the projects.
- In most cases, the economics resulted in nominal near-term savings. The longer terms savings often were the driving factors.

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D.4 Analysis of Wind Generation Options for Greensburg, Kansas

Tom Wind
Wind Utility Consulting

Executive Summary

The city of Greensburg faces some key decisions regarding the source of electricity for the city as it rebuilds after the May 2007 tornado. This preliminary study considers five principal wind energy options for the City, and explores some ramifications of whether or not the City continues to operate a municipal utility, and the City's green electricity goals.

The city could choose to sell its municipal electricity system and depend fully on electricity from the current local cooperative, which expects to have 10% wind-generated electricity by the end of 2007. The city could purchase more renewable energy credits annually, to raise its percentage of wind energy from 10% (local cooperative) up to as much as 100% (Option 1). However, this wind-generated or green electricity would not be obviously visible to the residents or anyone else.

With the approval of the local cooperative, larger individual customers (school, hospital, own businesses with larger energy needs) could install their own grid-connected, mid-sized wind turbines, up to 200 kw per customer (Option 2). This would increase the amount of green electricity in the city and provide good green visibility. However, the cost of energy from mid-sized turbines is much higher than from one or two large turbines.

If the city retains its municipal electricity system, it has several more options for wind-generated green electricity, depending on the city's goals and economic possibilities:

- City-owned large wind turbines at the edge of city could provide potentially 50% green electricity and be very visible (Option 3).
- City-owned large wind turbines with energy storage could potentially provide the city with up to 90% green electricity, and demonstrate a revolutionary vision (Option 3-A).
- The school and hospital (largest individual energy users) could each install a large wind turbine with energy storage systems, providing a very innovative demonstration to maximize the use of wind power for these energy users (Option 4).
- Private investors could install a small wind farm near Greensburg, connected to the local grid, and sell the power to the Greensburg municipal utility (a version of Option 3) or to the local cooperative (Option 5). This would provide some green visibility since the wind turbines would be located near the city.

After further guidance is provided, further studies should be done to refine the chosen options.

Table of Contents

Assumptions for Future Electricity Needs

There is some uncertainty about Greensburg's future electrical needs, since the amount of reconstruction of homes and businesses is unknown. Furthermore, even with more energy-efficient homes, the amount of electricity needs for each home will depend upon the amount of renewable energy used by each home. For example, solar photovoltaics and solar water heating on an individual home will reduce electricity needs.

Electricity needs might even increase if homeowners switch from natural gas heating to renewably-supplied electric heating. One possibility is to convert nearly all gas heating to electric heating. This would include using a combination of heat pumps and thermal heat storage. All of this new demand for electricity could be met by a couple of large wind turbines. This concept of using wind power for heating has been coined "Green Heat." Converting electricity into thermal energy, especially during off-peak hours, provides a means of energy storage when the wind doesn't blow or the sun doesn't shine. Thermal storage units have been used many years by thousands of customers of electric cooperatives in the Dakotas.

Natural gas usage could be nearly eliminated in city with the conversion to Green Heat. This increased need for electricity could also be supplied fairly economically by large wind turbines. Since wind power costs are relatively fixed once the wind turbines are installed, customers' heating costs would be nearly inflation proof, because they would not escalate with fossil fuel prices.

Using plug-in hybrid cars would further reduce fossil fuel usage in Greensburg, if the electricity for charging the cars' batteries primarily came from renewable electricity supplied by the city.

The city used 15.6 million kWh in 2005 with a peak load of 4.7 megawatts ("MW"). Regardless of the large uncertainty in future growth, the following assumptions were used for purposes of this wind power assessment:

- 2008 – 6.6 million kWh, 2.0 MW peak
- 2009 – 8.0 million kWh, 2.4 MW peak
- 2010 – 9.6 million kWh, 2.9 MW peak
- 2011 – 11.5 million kWh, 3.5 MW peak
- 2012 – 13.3 million kWh, 4.0 MW peak (full recovery)
- 2013 and beyond – 1.5% growth per year

Overview of Wind Generation Options

There are at least five different options for Greensburg to use wind power. An assessment was made of these options, based upon these assumptions about future electricity needs and information on the local wind resources.

Option 1. The city could purchase renewable energy credits or green tags for all electricity used in Greensburg.

Option 2. Individual customers with large energy use could install wind turbines at their locations to supply part of their power needs.

Option 3. The city's electric utility could install or purchase power from one or more large wind turbines to provide a significant percentage of the city's energy needs from wind power. Option 3-A has more wind turbines, along with an energy storage system.

Option 4. The school or hospital could install a large wind turbine with an energy storage system to supply the majority or all of the electricity and heating needs at each facility.

Option 5. The city could partner with private investors to install one or two large wind turbines at the edge of Greensburg, with all of the power sold at wholesale to outside electric utilities.

The viability of the options depends upon who owns the local electric system.

- *If the city sells its electric system, then it no longer makes any decisions about electric generation resource options or wind power. Under this scenario, there are few options available to effectively "green up" Greensburg. Southern Pioneer's electric power will be only about 10% green by the end of 2007. Individual electric customers could use additional green energy by installing their own wind turbines or solar photovoltaic ("PV") generators, within the limitations imposed by Kansas statutes.*

- *If the city continues to own its electric system, then it has several more wind power options, since it will make the decisions about its power supply resources. It could choose to install large wind turbines.*

If Greensburg retains ownership of its electric system, then all five of the options studied are available. If Greensburg sells its electric system to the current local cooperative, then only options #1 and #2 from above are available. (The cooperative does not have any green power options available at this time.)

The following pages present these options in more detail.

Option 1: Purchase Green Tags

The city could purchase renewable energy credits or green tags for all electricity used in Greensburg. With a bulk purchase of green energy, the cost premium might initially be less than 0.5 ¢ per kWh.

In 2005, the city used 15.6 million kWh before the tornado. Assuming sales in 2008 will be about 40% of that or about 6.6 million kWh, the cost premium at 0.5 ¢ per kWh would be $30,000 per year. This premium would rise as kWh sales increase with rebuilding. Furthermore, the cost of each green tag will likely escalate quickly as the U.S. adopts policies to reduce carbon emissions. The cost might be $125,000 in 2012. The annual average over 5 years might be $80,000.

This option would have the lowest up-front cost, since there would be no capital cost for wind turbines or solar PV generation. If the city owns the electric system, the cost of the purchase is in the utility budget. If the local cooperative owns the electric system, they would not be involved and the cost of the green tags would be in the city's general budget.

Option 2: Install Mid-Sized Wind Turbines for Larger Individual Customers

Larger individual customers – the school, hospital, water and waste treatment plants, and larger businesses -- could install mid-sized wind turbines at their locations to supply part of their power needs. This option would be applicable if there is adequate clear space where a wind turbine could be installed without bothering neighbors.

The only mid-sized turbine readily available in the U.S. is the Entegrity 50 kW unit. Each turbine on a 100' lattice tower would generate over 160,000 kWh per year at Greensburg. The facilities using more energy, such as the school and hospital, could each use the power from several turbines. From one up to four units could be installed to provide part of the electricity needs at each of the following facilities using net metering, up to a limit of 200 kW per energy user. If multiple units are purchased, then installation, maintenance, and servicing could be obtained at a discount. A local person would be trained to maintain the units.

An Entegrity 50 kW wind turbine would cost about $170,000, including installation. The operating cost would initially average about 3 ¢ per kWh. The fixed financing cost would be another 8.5 ¢ per kWh, based on a 20-year amortization at 5% interest. The total cost would be about 11.5 ¢ per kWh.

If the retail cost of electricity is initially 11 ¢ per kWh, the wind turbines will likely pay for themselves over their lifetimes. Electricity costs will likely escalate over time, if fossil fuels are used and carbon emissions are regulated.

Installing wind turbines requires extra capital up front, which may be difficult to justify. A capital contribution of $50,000 per wind turbine would lower the wind power cost to about 9 ¢ per kWh. This makes the wind turbine a more attractive investment with a more assured payback.

Option 3: Install City-Owned Large Wind Turbines

If the city continued to own the electric utility, it could install from 1 to 4 MW of wind generation to supplement its other power resources. Along with the wind generation, a reasonable mix of generating resources might include 4 to 6 MW of engine generation (natural gas or biodiesel) and a flexible supplemental wholesale power purchase contract. Since the purchased power would be less expensive than the engine generation, the engines would typically operate only a few hundred hours per year during peak load periods. If more than 2 MW of wind generation is installed, some type of energy storage may be cost-justified.

1 MW of wind generation will provide about 25% of Greensburg's projected energy needs in 2012, with 2 MW providing about 50%. The cost of supplemental purchased power becomes increasingly more expensive per kWh with increasing amounts of wind generation. This is due to wind power's variable output, which must be accommodated by the purchased power schedule.

The installed cost of a large wind turbine is about $2 million per MW. It could be connected directly to the distribution system, rather than the transmission system. Each MW would generate between 3.1 and 3.6 million kWh (assuming 35 to 40% annual capacity factor), depending upon the turbine model.

There are at least two options for financing the wind turbines:

1. *The City could sell Clean Renewable Energy Bonds, which are zero-interest bonds with a term of about 15 years. The cost of wind power would be 5.5 ¢ to 6.5 ¢ per kWh during the 15-year debt repayment period, and less than 2 ¢ per kWh for the last 10 years of its expected life.*

2. *An alternative to City ownership would be to purchase wind power from a private entity that would agree to purchase and install wind turbines at Greensburg, and connect them to the distribution system. The private entity would use the federal production tax credit. The cost of the wind power might be 0.5 to 1.0 ¢ per kWh higher, depending upon the equity return required for the investment.*

If more than about 2 MW of wind generation is installed, Greensburg would either require a special supplemental power purchase agreement or an energy storage system. Either of these would be required to accommodate the great variability in the wind generation. Even though engine-driven generation may be able to accommodate such variability, the high fuel costs would likely make it more expensive than either of the other two options.

A high-level estimate was made of the total cost of generation for one scenario with 6 MW of engine generation, a 2 MW purchase of wind power, and a special supplemental power purchase agreement from the grid. This generation combination would provide Greensburg with about 50% green power, which is probably the highest percentage use of wind power for a grid-connected utility in the U.S.

A summary of some basic assumptions is shown on the following table.

Assumptions Used in Preliminary Analysis	
6.00	Engine Generation Installed, MW
$3.60	Capital Cost of Engine Generators, $ Millions
4.0	Engine O&M Cost less fuel, ¢ per kWh
$8.50	Natural Gas cost, $ per MMBTU
4.0%	Annual escalation in natural gas cost
2.0	Wind Generation Purchased, MW in 2011
6.0	Wind generation Power Purchase Agreement, ¢ per kWh Flat
38%	Annual Capacity Factor for Wind Generation at Greensburg
6.9	Special Supplemental Power Purchase Rate, ¢ per kWh in 2011
Notes:	Fixed financing charges were based on 20 year bonds at 5% interest. The supplemental power rate escalated 3.5% per year and also increased with the % of wind generation used. Engine generation was limited to 200 full load hours per year.

Based on the above assumptions, the capital cost of generation to the city would be $3.6 million, with an all-in cost of about 9 to 10 ¢ per kWh in 2012 when the city grows into the full capability of the installed generation. The cost per kWh would be a little higher at first, since the kWh needs of the city would initially be lower. To keep costs down at the beginning, the engine and wind generation could be installed in two phases to better match the city's growing needs.

The cost of using biodiesel instead of natural gas might result in the total generation cost being perhaps 1 ¢ per kWh higher.

If the cost of electric distribution is another 4 ¢ per kWh on top of the generation cost (based on using natural gas), the total retail cost would be about 13 to 14 ¢ per kWh. This is likely higher than nearly all other Kansas utilities. If a target retail rate of 11 ¢ per kWh is assumed (actual cost in 2005), the generation cost component would have to drop to 7 ¢ per kWh.

In order to reduce the generation cost from the 9-10 ¢ range down to 7 ¢ per kWh, a grant or gift would be required to help buy down the cost of the engines, the cost of the wind power, or the cost of the supplemental purchased power. Any one of the following grants or gifts would accomplish this alone:

- *The capital cost of 2 MW of wind generation (making the wind power cost 1.5 ¢ per kWh) or a wind power purchase agreement of 1.5 ¢ per kWh,* ***or***
- *Supplemental purchased power cost lowered from 6.9 ¢ to 2.0 ¢ per kWh,* ***or***
- *A $2.7 million grant toward the $3.6 million cost for the engines*

Option 3-A: Install City-Owned Large Wind Turbines with Energy Storage

There are two methods of attaining an even higher percentage of wind power.

The first method is to obtain a special supplemental power purchase and sales agreement that would allow power to either be purchased or sold depending upon the amount of wind generator output. This could best be accomplished by having a larger utility deliver or absorb the extra power into its control area. This could be accomplished by dynamically scheduling power automatically and it would not have to be done by the local cooperative, although the local cooperative would likely want to collect transmission service charges from Greensburg. No cost estimate was made for this option.

The second method of using more wind power is to add an energy storage system. A scenario using 4 MW of wind generation was developed that uses a 2 MW battery storage system and 4 MW of engine generators. The battery was assumed to cost $1.5 million. A 2 ¢ per kWh battery operating cost was assumed with a round-trip efficiency of 75%, and an operating capacity factor of 33%. Energy losses would add perhaps 1.5 million kWh annually to the city's needs.

This scenario allows wind generation to provide about 90% of Greensburg's energy needs. This scenario results in generation costs of about 10 ¢ per kWh. In order to reduce the generation cost from 10 ¢ to 7 ¢ per kWh, <u>any one</u> of the following grants or gifts would accomplish this alone:

- *The capital cost of 3 MW (out of 4 MW) of wind generation making the cost of wind power 3.0 ¢ per kWh, or a wind power purchase agreement of 3.0 ¢ per kWh,* ***<u>or</u>***

- *The capital cost of the battery storage system along with the elimination of the 2 ¢ operating cost* ***<u>plus</u>*** *a $1.2 million grant toward the $2.4 million cost for the 4 MW engine generators,* ***<u>or</u>***

- *All Green Tags are sold for 2.5 ¢ per kWh.*

Option 4: Install Large Turbines for School and Hospital

A larger wind turbine could be installed to provide the majority of the electricity and heating needs of the school or the hospital. The Kansas K.S.A. 55-422 law specifies the minimum standards for utilities interconnecting renewable generators. Since the current local cooperative has adopted these minimum standards, it has indicated that it would not allow a large wind turbine to be used for Greensburg's school or hospital, if it serves these facilities. The law also limits net metering to 200 kW of wind generation for commercial customers. However, if the city maintains its utility, it can use less restrictive requirements if it wants to encourage renewable generation. Therefore, it was assumed that the city would allow its customers to install large wind turbines. Since the law limits net billing to 200 kW, net billing was not assumed in the analysis for large turbines at the school and hospital.

The smallest new large turbine readily available in the U.S. is 900 kW. This size of turbine would cost about $1.9 million installed, and generate about 2.8 million kWh per year. This amount of electricity would probably be enough to supply both the electricity needs and heating needs of either the new school or the new hospital.

To best utilize the variable nature of wind energy and minimize the utility cost, the school's heating and cooling system would need to include some amount of thermal heat and ice storage. This could easily be accommodated into the design of the new school or hospital. Although these technologies exist today, this would likely be the first school or hospital in the U.S. designed to have its energy (electricity and heat) supplied primarily by wind power.

A 900-kW turbine financed with 20-year tax-exempt bonds at 5% interest would result in fixed financing charges of 5.5 ¢ per kWh. With operating and maintenance costs adding another 1.3 ¢ per kWh, the total cost of wind power would be about 7 ¢ per kWh.

Without net metering, the school and hospital would have to sell its excess electricity back to the city at some reduced wholesale cost, perhaps at 5 ¢ per kWh. Since the school's and hospital's electricity needs have not yet been determined, the amount of excess wind generation is unknown. It was also assumed that the city would sell its electricity on an energy basis only, with no peak demand charges. The retail rate was assumed to be 11 ¢ per kWh.

If a thermal and ice storage system is installed, the excess generation will be minimized. A preliminary estimate of this type of storage equipment is $750,000. If this cost is added to the wind turbine, the wind power cost would increase from 7 ¢ to the equivalent of 9 ¢ per kWh.

Even though the wind power and storage equipment costs about 9 ¢ per kWh, which is less than the 11 ¢ retail electricity rate, the project may not be economically attractive due to its high up-front cost. A capital contribution or grant of $500,000 per large wind turbine for the school and/or hospital would reduce the net cost of electricity from 9 ¢ down to about 7.5 ¢ per kWh. At this level, the net investment of about $2.15 million would have a return that might be attractive enough to economically justify the installation.

Option 5: Install Privately Owned Large Wind Turbines at Greensburg

Private investors could install one or two large wind turbines at the edge of Greensburg and sell all of the wind power to the local cooperative at a negotiated price. It is assumed here that the private wind farm would have to offer prices competitive with the large corporately-owned wind farms sited in the windiest sites.

Based on this reasoning, the relatively lower wind resources at Greensburg and its lack of economy of scale would result in the private investors earning a lower return on their investment when compared to other corporate wind farms. Therefore, a private wind farm at Greensburg would require a grant to be economically competitive enough for the local cooperative to purchase the power.

A preliminary estimate of the grant amount would be 33% of the cost of the wind farm. A 5-MW wind farm costing $2 million per MW, or $10 million, would require a $3.3 million grant.

The following table compares the results of this analysis of wind turbine options for Greensburg.

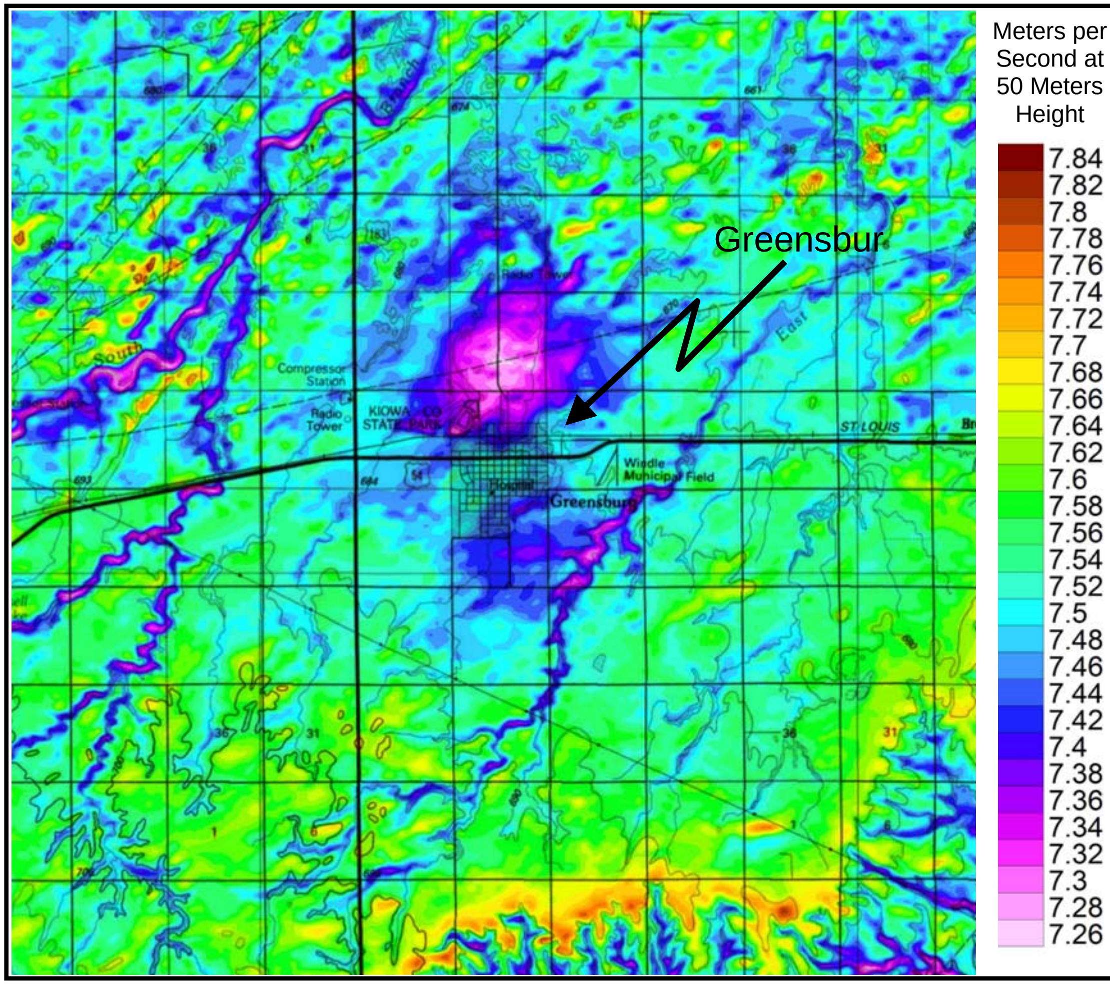
Summary of Analysis of Greensburg Wind Power Options

	Title	Description		Total Capital Cost $ Millions[2]	Contribution Needed to be Viable[3]	Feasi-bility Under Co-op Control	Advantages	Disadvantages
1	Purchase Green Tags	Bulk purchase of green tags	100%	n/a	$80,000 per year average over next 5 years	Yes	Very simple and low cost	There is no visual evidence of using renewable energy, requires annual commitment.
2	Mid-Sized Turbines for Larger Individual Customers	Ten customer-installed 50-kW wind turbines	12%	$1.7	$50,000 times 10 turbines is $500,000	Probably	Ten turbines would be very visible and might appear greener than 2 larger turbines	This option only provides 12% green power and the cost of the green power is much higher
3	City-Owned Large Turbines	2 MW of wind, 6 MW of engine generation	50%	$3.6	$2.7 million or 1.5¢ wind power PPA	No	One or two large wind turbines will be seen for many miles	Special control system for engines and turbines will be required
3-A	City-Owned Large Turbines with Storage	4 MW of wind, 4 MW of engine generation, 2 MW of storage	90%	$3.9	Free Energy Storage System of 3.0¢ wind power PPA	No	Turbines will be very visible; 90% wind power will be revolutionary for being grid connected	A more complicated system would require more utility technicians
4	Large Turbines for School & Hospital	Each: 900-kW turbine with thermal and ice storage systems	15%	$5.3	$500,000 each system; school and hospital both = $1,000,000	No	Innovative demonstration to maximize the use of wind power	Equipment and innovative control systems will require technicians to maintain
5	Privately Owned Wind Farm	5-MW wind farm	N/A	$10.0	$3.3 million	Probably Not	No capital required for the city; wind farm privately owned	The green power will go to the local cooperative and not the city

[1] This column shows the percentage of electricity used in the city that would be from wind power.
[2] This is the total capital cost of generating equipment needed. The capital for the last option would come from private sources.
[3] This is the gift or grant needed to make the options economically viable and attractive for the city or owners of the equipment.

Addendum: Preliminary Estimate of Wind Speeds in the Greensburg Area

In general, the Greensburg area has good wind resources. The following two maps show the approximate wind speeds in a 10-mile by 10-mile and 5-mile by 5-mile area around Greensburg. This map is based on the wind resource database compiled by the Kansas Corporation Commission. The consultants used higher resolution topography and land cover data to develop this higher resolution wind speed map. A more accurate and costly assessment of the wind speeds can be made once a commitment is made to proceed with wind power. The final diagram indicates the prevailing wind directions for Greensburg.

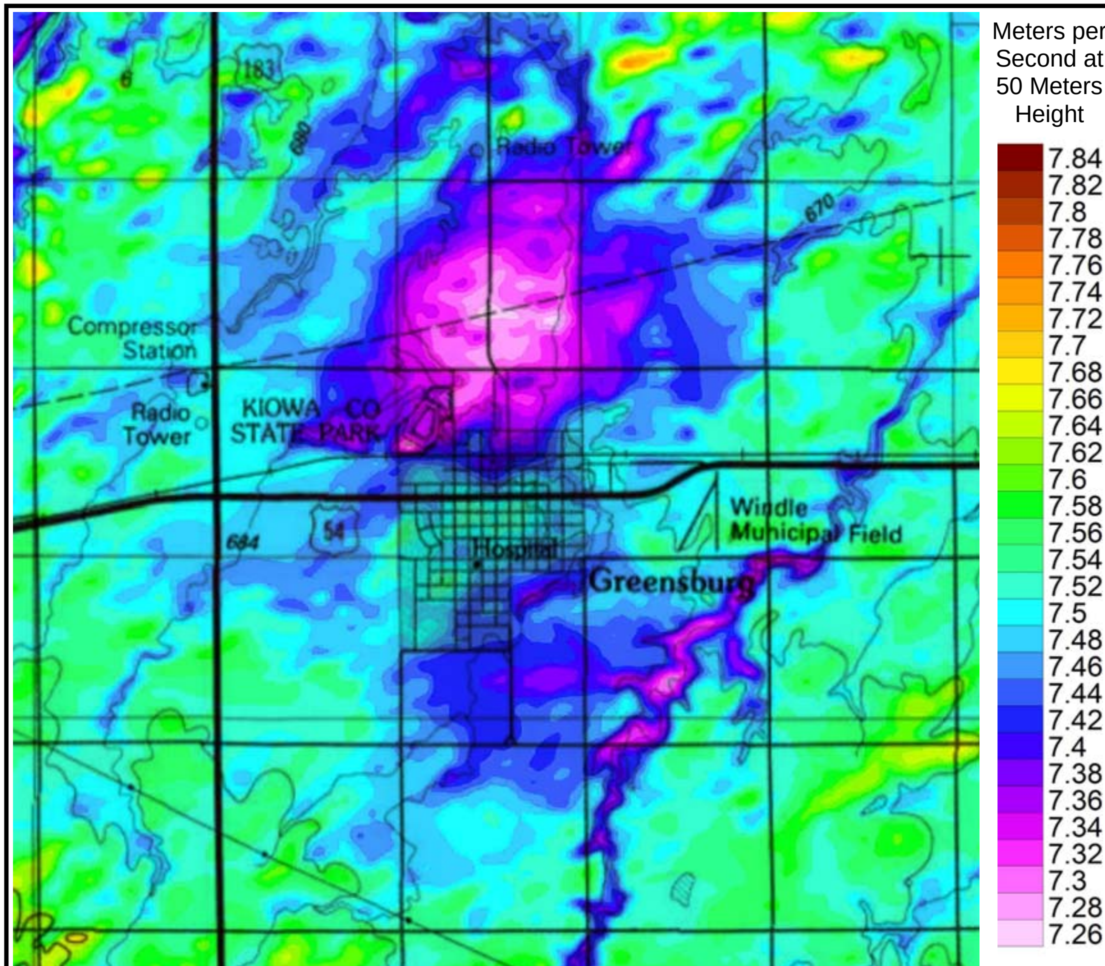


This high-resolution map shows the estimated mean annual wind speeds in a 10- by 10-mile area centered on Greensburg. Since it is based on the state's data, it is no more accurate than their data. However, it accurately shows differences in wind speeds in the area. Therefore, it can be used for determining the best sites for wind generation in the area.

Wind Speed Map around Greensburg, Kansas

Map is based on the Kansas Corporation Commission 1,000-meter resolution wind speed database.

Wind Utility Consulting, PC

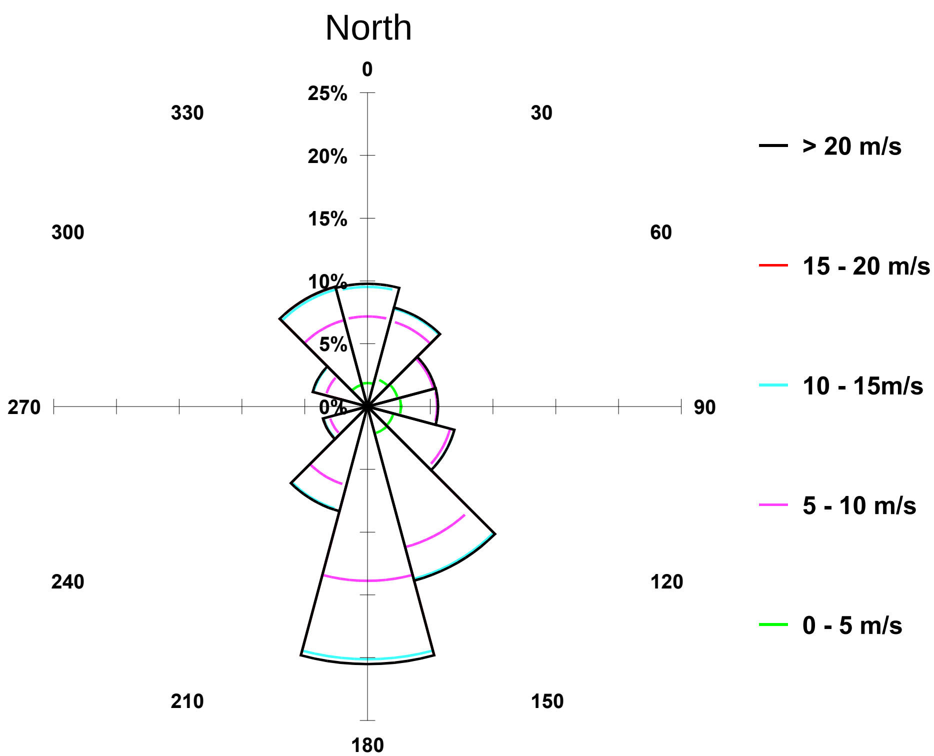


This is an enlarged 5- by 5-mile section of the high-resolution map centered around Greensburg. Although there are many shades of color in this map, there are only modest differences in the wind speed. A large wind turbine could probably be sited within this area and connected to the local distribution system with minimal or modest distribution system reinforcements.

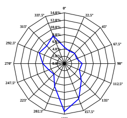
Wind Speed Map around Greensburg, Kansas

Map is based on the Kansas Corporation Commission 1,000-meter resolution wind speed database.

Wind Utility Consulting, PC



This wind rose data is from the closest met tower with publicly available data. It shows the predominant wind directions to be from the south and north.



Wind Rose for Greensburg, Kansas Based on Deerfield, Kansas Met Tower

Wind Utility Consulting, PC
September 2007
Wind rose is based on met tower data obtained from the Energy & Environmental Research Center (EERC) for the years of 1996-1998.

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D.5 Analysis of Greensburg Municipal Utility Business Strategies to Become Green

Thomas A. Wind
Wind Utility Consulting

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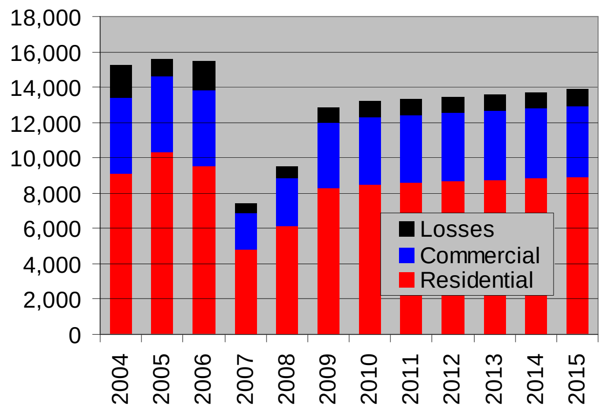
National Renewable Energy Laboratory

Executive Summary

The purpose of this report is to evaluate the business and economic feasibility of obtaining a significant percentage of Greensburg's electricity from wind power. Lying before the City of Greensburg is an attractive offer by Southern Pioneer Electric Company to take over the electric utility operations now owned and operated by the City. This offer does not include the installation of large wind turbine to supply wind power to Greensburg. Although this attractive offer originally fit the City's needs, the City's needs have since changed. A large wind turbine located at Greensburg has now become an important visual part of Greensburg's mission to be a national model for a green and sustainable community. Therefore, the City must reconsider the option of keeping its electric utility so that it can make sure it can get a significant amount of power from a locally installed wind turbine.

FIGURE 1
Historical and Projected Electricity Needs, in Megawatt-hours



Estimates were made by Wind Utility Consulting, PC ("Consultants") of the future electricity needs of the City and are shown in Figure 1. Although there is a lot of uncertainty in Greensburg's future, the amount of electricity needed after full recovery was projected to be about 13 million kWh, with some modest growth thereafter. Electricity needs are expected to be less than the past due to gains in energy efficiency. These projections were then used in a power supply and financial model specifically developed for the City's electric utility. This model was used to project future electric utility revenues and expenditures to determine the cost of electricity for three basic strategies shown in Table 1 below. Some of the key assumptions used in this analysis are:

1) If the City sells its electric utility system to Southern Pioneer, the local electric generating plant would be retired. A 10% electric city franchise tax would be applied to Southern Pioneer's electricity sales in the city. The proceeds would be used to pay for at least part of the free and discounted services currently provided by the City's electric utility.
2) If the City keeps its electric utility, it would obtain a new long-term wholesale power supply contract that would provide terms favorable for the use of locally-generated wind power. The Kansas Power Pool could potentially provide such a contract which would provide load and generation following services and power purchase rates based on energy needs only, rather than energy and peak demand.
3) Greensburg would commit to 100% green power by using a combination of donated or purchased renewable energy credits and/or locally generated wind power.
4) Future regulations limiting greenhouse gas emissions will raise the cost of electricity generated from fossil fuels for all wholesale power supply providers.

TABLE 1 – Comparison of Strategies

	Strategy 1 Accept MOU and Offer from Southern Pioneer	**Strategy 2** Retain Electric Utility, No Large Wind Turbines	**Strategy 3** Retain Electric Utility, Install 1 to 3 Large Turbines
Advantages	Lower rates, No debt, No management needed, Possible cash gain from utility sale, Future patronage dividends to residents	Local power plant kept for emergency backup, more city jobs, continuation of free and discounted services and income to City	Same as Strategy 2 plus having one or more large wind turbines located at Greensburg
Risks	Extended outages due to transmission line outages and no local generators	Even higher rates if City doesn't grow	Same as Strategy 2 plus wind turbine operational problems
Average Electric Rates			
Years 1-5 (2008-2012)	11.0 ¢	12.3 ¢	12.3 ¢
Years 6-10 (2013-2017)	14.1 ¢	14.5 ¢	≈ 14.6 ¢
Years 1-10 (2008-2017)	12.6 ¢	13.4 ¢	≈ 13.4 ¢
% Difference (2008-2017)	Reference	+ 6 %	≈ 7 %
% of Wind Power Used	13 %	13 %	39-100 %
% of R.E. Credits Used	87 %	87 %	61 - 0 %
Total % of Green Power	100 %	100%	100%

Based on the results of this study, the following conclusions can be made:

1) Under Southern Pioneer service, electric rates in the City will initially average about 1.3¢ per kWh less expensive than they would be under City ownership. The savings narrows to around 0.5¢ per kWh over the longer run.
2) If the City retains ownership of its electric system, electric rates will likely stay about the same for the next three years, followed by average increases of 3.5% per year. In general, rates would be 6 to 7 % higher under City ownership over the next ten years. The higher rates are primarily due to maintaining the local generating plant and providing free and discounted services to the City and its residents.
3) With a favorable new wholesale power supply contract, the City would likely be able to install from one to three large turbines (1.5 to 4.5 MW) with little if any need for electric rates higher than if there were no wind turbines. It would take about 4 MW of wind generation to provide the equivalent of 100% of the City's electricity.

Based on these conclusions, the Consultants recommend that the City retain ownership of its electric utility. This will provide two main benefits: 1) local generation will be maintained that will keep the lights on for extended transmission line outages, and 2) the City can install one or more large wind turbines that will provide a visible source of green power for Greensburg.

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Forward

A preliminary discussion draft of this report was presented by the Consultants at a January 3rd, 2008 meeting in Greensburg with representatives from the City, Southern Pioneer, Sunflower, NREL, and others. Based on the detailed discussions at the meeting, the Consultants acknowledged that some financial and power supply assumptions needed to be adjusted. Subsequent discussions provided more clarification and information. Therefore, the analysis has been updated with better assumptions and this report reflects the revised analysis. A change in two key assumptions has significantly affected the results and findings in this report. The first key assumption change was the inclusion of a 10% City franchise tax on electricity sold by Southern Pioneer if it acquires the City's electric distribution system and serves the City on a retail basis. The franchise tax will partly compensate the City for the many financial benefits that its electric utility provided the City, such as free and discounted services and labor. The second key assumption change was in the structure of a future wholesale power supply contract if the City continues ownership of the electric system. Originally the analysis assumed a two part wholesale rate with both demand and energy charge components. This revised analysis assumes a postage stamp rate of 4.5 ¢ per kWh, meaning that all power purchased by the City will cost 4.5 ¢ per kWh, regardless of the level of the City's peak demand or its annual load factor. This effectively reduces the cost of purchased power for the City. Collectively, these two key changes in assumptions show much less savings in electricity costs under Southern Pioneer service compared to City ownership of the utility using wind energy.

Introduction and Overview

Because of the devastating damage from the May 4, 2007 EF5 tornado to the City of Greensburg ("City"), most of the City's electric system has been repaired or replaced by all new poles and wires and service is now available when needed for the construction of new homes. Although the generating plant building suffered extensive damage, the five dual-fueled engines suffered only modest damage. The engines and some subsequent water damage can be repaired; however, a complete new building will be required.

Southern Pioneer Electric Company and Mid-Kansas Electric Company ("MKEC") helped the city with managing the distribution system reconstruction. A Memorandum of Understanding ("MOU") between Southern Pioneer and the City was signed with the intent of eventually transferring ownership of the city's electric system to the cooperative. If this MOU is with a follow-up asset sales contract, the City would no longer serve electricity to its residents, nor would the City have any responsibility for procuring future sources of electricity. Signing the MOU clearly brought advantages to the City during the very difficult rebuilding period by eliminating the need to rebuild and manage the electricity system, and by ensuring the City's residents an economical supply of electricity into the future from a consumer-owned utility.

The growing interest in rebuilding Greensburg as a national model for sustainability has brought new attention and interest in using renewable energy as a primary source of energy for the City. Sunflower Electric Power Corporation ("Sunflower") supplies power to MKEC, which would in turn supply power through Southern Pioneer to Greensburg. Although Sunflower generates the vast majority of its electricity with coal, it will be getting about 10% of its electricity from wind power in 2008. If Sunflower meets the State's goals, it will generate 20% with renewables by 2020. Therefore, MKEC's electricity is approximately 10% green at this point in time. In response to the City's request for a larger percentage of green power, MKEC has generously offered to provide Renewable Energy Credits (RECs") for a three-year period at no extra charge to the City, which would make the city's electric supply 100% green for the three-year period. Due to ownership structure, policies, and economics, it would be difficult for MKEC and/or Sunflower to justify the installation of a wind turbine at Greensburg for supplying wind power exclusively to the City.

The City's leaders now believe that the visual impact and prominence of a large wind turbine on the City's skyline is important in fulfilling the vision of a green and sustainable Greensburg. If the City transfers ownership of its electric system to Southern Pioneer, then it would essentially have little need for the power from a utility-scale wind turbine, and could not justify installing a large wind turbine. Although a third party could install a large wind turbine at Greensburg, the wind power would have to be sold to MKEC or another remote power company, and would be blended in with its other power resources. Given the economies of scale of wind generation and the better wind resources in other locations, it would not be economically attractive for a third party to install a large wind turbine at Greensburg for selling into the wholesale market. Even if a large wind turbine were installed, the wind power would not be dedicated to use by Greensburg. This report evaluates the option of retaining ownership of its electric system, so that it can install and use locally generated wind power for the community.

Greensburg's Future Electricity Needs

Prior to May 5, 2007, Greensburg's electricity needs varied from a low of about 1.0 Megawatts ("MW") during the nighttime in spring and fall, to a maximum of 4.5 MW during the hottest day of the summer. Figures 1 and 2 illustrate the daily minimum and maximum loads for most of the year of 2006. The maximum daily load is greatly increased, due to air conditioning loads during the summer.

The black squares in Figures 1 and 2 show the daily average engine generation in kW during the hours when the engines were running. The engines ran for about 250 hours in 2006 and 740 hours in 2005, generating about 1.2% of the City's needs in 2006, and 5% in 2005.

FIGURE 2

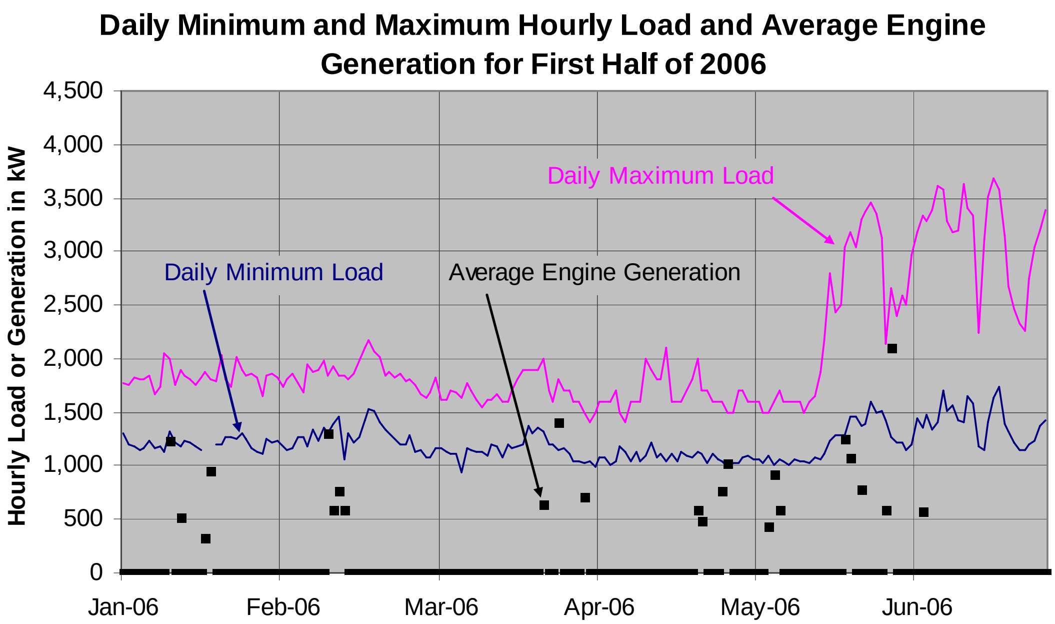


FIGURE 3

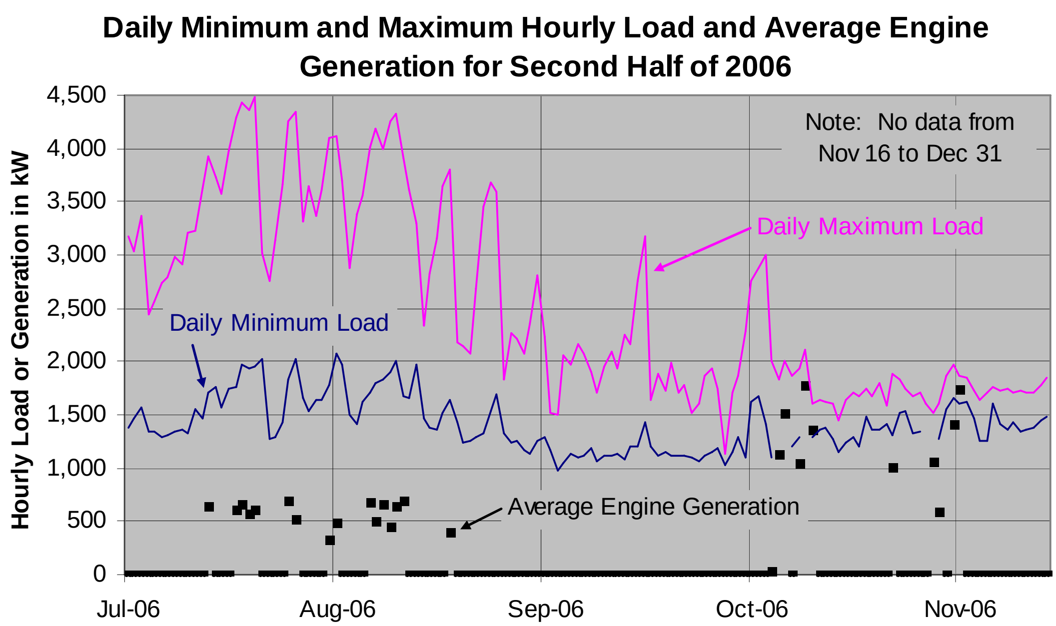


FIGURE 4

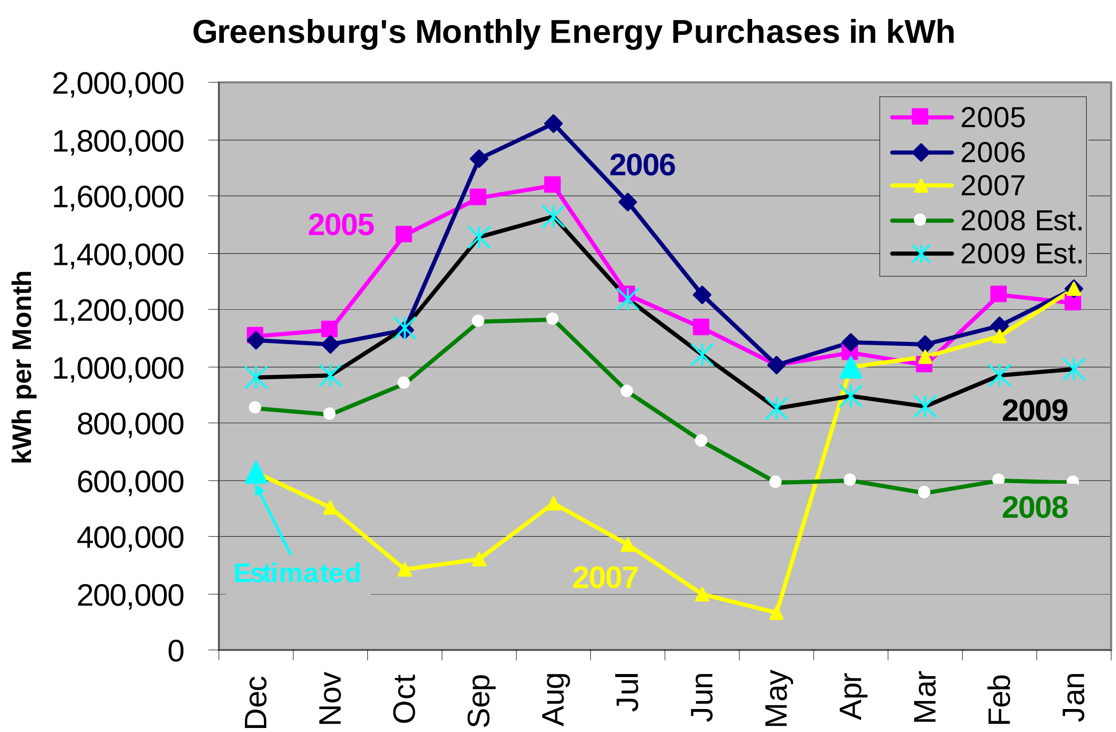
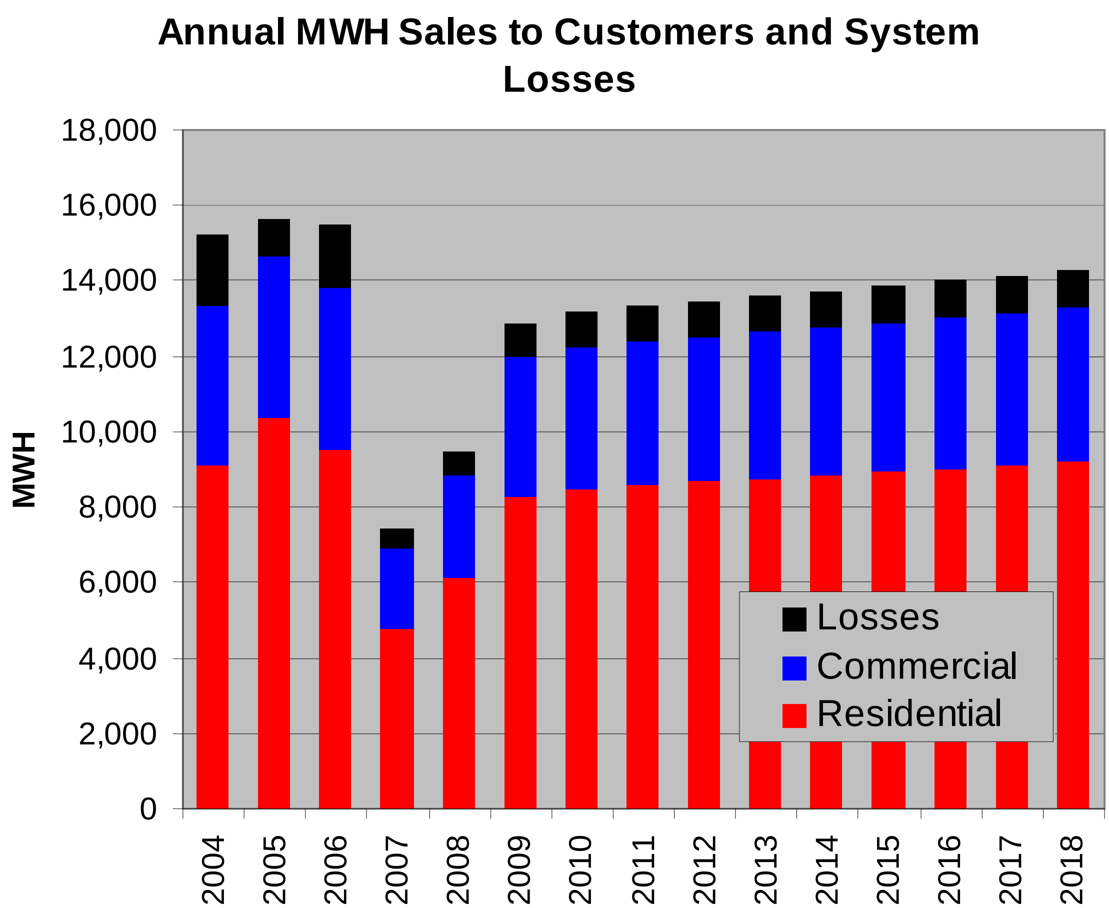


Figure 4 depicts the historical monthly energy purchases from 2005 through 2007, along with the Consultants' estimates for December of 2007, and all of 2008 and 2009. These estimates were primarily based on judgment, and the current pace of new home construction. Energy purchases historically represented at least 95% of the City's energy needs, with the balance coming from engine generation.

Figure 5 portrays the historical and projected annual electrical energy needs for Greensburg. The electrical needs include residential customer sales, commercial customer sales, and losses. The losses include a small amount of power furnished without charge. System losses are expected to be reduced from around 10% of electric sales down to 7.5% of sales, since the newly built distribution system has a higher 12.47 kV voltage level than the older system's 4.16 kV voltage level.

FIGURE 5



The totals shown in Figure 5 are also shown in tabular form below.

TABLE 2 – Projected Annual kWh Electricity Needs for Greensburg

2007	2008	2009	2010	2011	2012 & On
7.4 million	9.5 million	12.9 million	13.2 million	13.3 million "Full Recovery"	1% growth per year

These projections during the recovery period are much higher than originally assumed in the Consultants' October 2, 2007 wind generation options report, thus reflecting a quicker recovery. These new estimates are based on a more thorough evaluation of recent energy sales trends.
There is a great deal of uncertainty in the future electricity needs of Greensburg. The uncertainty is due to:

- The number of new homes that will be built
- The energy savings due to new appliances and air conditioners
- The number of solar photovoltaic panels used by customers
- Use of wind turbines by larger customers, such as the school and hospital (***Should the City encourage the school and hospital to install wind turbines if the City generates most of its electricity with even larger and more cost-efficient wind turbines?)***
- The amount of electric heating added for new homes (***Should Greensburg adopt an incentive rate to encourage conversion from non-renewable natural gas to electric heating, based on renewable energy generated by the City?)***
- The energy needs of the new biodiesel plant
- Energy charging needs for future plug-in electric vehicles

Given these uncertainties, the amount of energy sales could be significantly different than projected by the Consultants. Nevertheless, the above estimates were used for these business strategy evaluations.

Overview of Potential Business Strategy Scenarios

Several potential business strategy scenarios were developed to provide the City leaders information about the expected costs and electric rates for retaining ownership of their electric utility. The business strategies are:

1) **Strategy 1 – Accept MOU and Offer from Southern Pioneer:** The City would transfer ownership of its electric system per the MOU and dispose of its dual-fuel engine power plant. The City would then work to encourage some entity to install one or more large wind turbines at Greensburg. The power would likely be sold to MKEC and/or Sunflower and blended with their other resources.

2) **Strategy 2 – Retain Electric Utility, No Large Wind Turbines:** The local dual-fuel generating plant would be refurbished or replaced by new units and a new wholesale power supply contract to provide standard grid power would be procured. The percentage of green power used would be equivalent to that from the wholesale provider, unless additional green RECs were purchased. This scenario serves as a cost reference for Scenarios 1 and 3.

3) **Strategy 3 – Retain Electric Utility, Add Large Wind Turbines:** Again, local generation would be used, along with adding from one to three 1.5 MW wind turbines at Greensburg, which would provide three different levels or wind power. Installing only one large wind turbine would likely provide the highest penetration of wind power for any city in the U.S.

Common to the last two scenarios, wherein the city retains the electric utility, is having local engine generators to provide back-up power when the transmission grid is down. This is one of the primary benefits of having a municipally owned electric utility. However, it does add to the cost of electricity. A recent ice storm has proven the value of having local generation available. The local economy and daily course of life grinds to a halt when the lights go out. The large number of city residents that have recently added standby generators for their homes and businesses at great expense proves that having local standby generation is a high priority for Greensburg residents.

There are two options for having local engine generation: 1) refurbishing the existing generating plant, and 2) replacing the existing plant with modern new engine generators. Based on inspections made after the tornado, the existing engines suffered minor physical damage despite the destruction of the building. Refurbishing the existing plant would require a new building, and some repairs for physical and water damage to the five Fairbanks & Morse engines and generators. The cost of the repairs and new building has not been determined, although it would likely cost at least $1.0 million. All of the existing engine generators can burn diesel fuel or natural gas. Using natural gas instead of diesel fuel reduces fuel cost by at least one-third. The second option would be to retire and scrap out the existing engine generators and replace them with newer skid-mounted units that are highly automated and low maintenance. The cost for this was estimated to be somewhere between $2.0 and $4.0 million, depending upon the amount of generating capacity, and whether they are dual-fueled or oil-fueled. It was assumed in this study that insurance proceeds would fund either of the two options for having local engine-generating capacity.

Each of these three scenarios is discussed in more detail below.

Strategy 1 – Accept MOU and Offer from Southern Pioneer

Under this strategy, the City and Southern Pioneer would continue on with the original plan to turn over and sell the City's electric system to Southern Pioneer. Southern Pioneer has incurred considerable costs for assisting with rebuilding the system. The MOU calls for purchasing the electric system assets at a negotiated price that reflects the value of the electric system from a revenue perspective, less the costs Southern Pioneer incurred for rebuilding. The dual-fuel engine generating plant would be retired and scrapped out. It was assumed that the insurance proceeds would retire the past debt for engine repairs and the recent distribution system improvements. Depending upon the insurance settlement, the City might have some financial gain upon selling its electric system to Southern Pioneer. However, no financial gain was assumed in this analysis.

The action steps required are relatively simple and include:

1) Accept offer from Southern Pioneer
2) Determine appropriate franchise tax on electricity sold by Southern Pioneer
3) Settle with insurance company
4) Dispose of electric generating plant
5) Repay balance of any debt owed for the electric system
6) Acquire renewable energy credits after three years

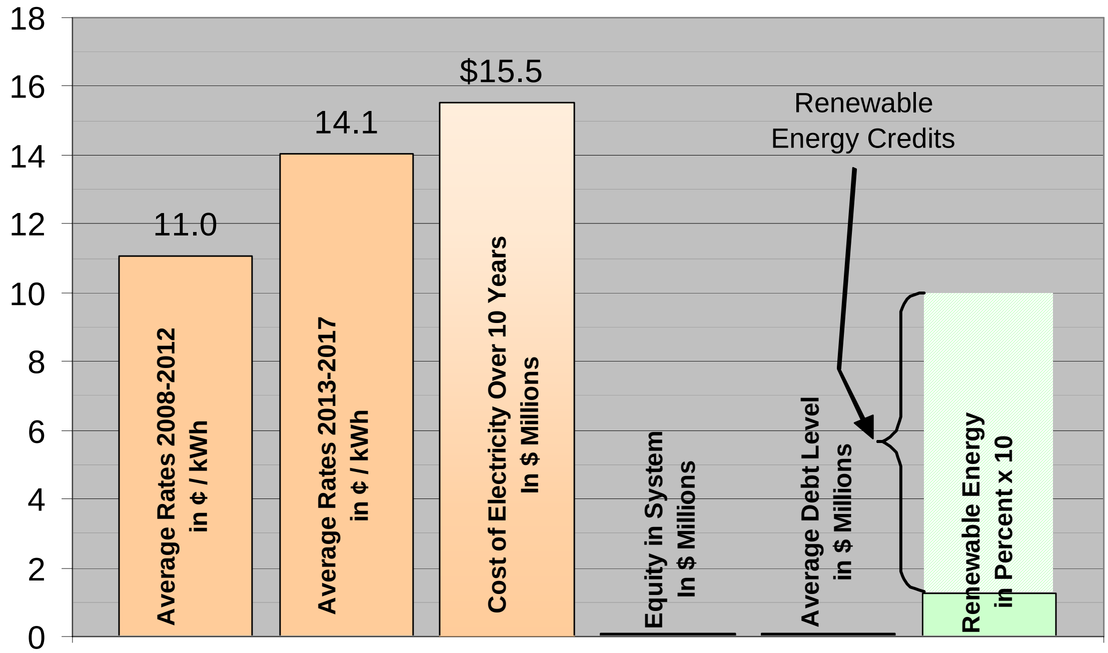
Table 3 below lists the advantages, disadvantages, risks, and uncertainties for Strategy 1.

TABLE 3 - Strategy 1 – Accept MOU Advantages, Disadvantages, Risks, and Uncertainties	
Advantages	Lower electric rates for residents and businesses
	City will likely have a net cash gain after selling its system to Southern Pioneer and repaying its remaining debt. The amount of cash gain is undetermined at this time.
	No bond issues required for the electric system, eliminating financial risk if City does not grow as expected
	City does not have to manage the reconstruction and operation of the electric system
	Residents can eventually receive patronage dividends from cooperative
	Sunflower provides three years of renewable energy credits
Disadvantages	No local generating plant to keep lights on for long transmission outages
	Fewer jobs in City, less financial support for other City employees
	City must implement franchise tax to cover loss of free and discounted services (such as street lighting) now provided by the electric utility and its employees, and loss of net margins from the electric utility
	Will be more difficult to get large wind turbines installed at Greensburg, since City looses control over energy resource decisions
	Southern Pioneer will likely not provide net metering for residents who install PV panels and wind turbines, thus greatly reducing their economics
Risks and Uncertainties	Risk of extended power outage due to major transmission outage
	Percentage of renewable energy used by Greensburg is uncertain, since the installation of large wind turbines is not controlled by the City

The electric utility now provides several financial benefits to the City as listed in the table above. Although no specific analysis was done for Greensburg, information from a national survey and the Kansas Municipal Utility Association was used to project that a typical small Kansas municipal utility might provide financial benefits to a city equal to 13% of electric revenues. Although the lost benefits might be higher for Greensburg, a more conservative 10% loss in benefits was assumed to be compensated by a 10% franchise tax which was added to the cost of Southern Pioneer's electricity. Therefore, a 9 ¢ per kWh average rate from Southern Pioneer will cost the customer 9.9 ¢ per kWh with the franchise tax.

Figure 6 provides a graphical summary of the key financial metrics for this strategy. The left two bars in the chart show the predicted electric rates with the franchise tax for the city residents for the first five-year period from 2008 through 2012 (11.0¢ per kWh), and for a second five-year period from 2013 through 2017 (14.1¢ per kWh). This estimate was based on how the Consultant believes electric rates will generally escalate in the future for Southern Pioneer. It was assumed that 55% of Southern Pioneer's cost is associated with the operations and investments in their distribution system.

FIGURE 6 – Financial Summary for Strategy 1 – Accept MOU

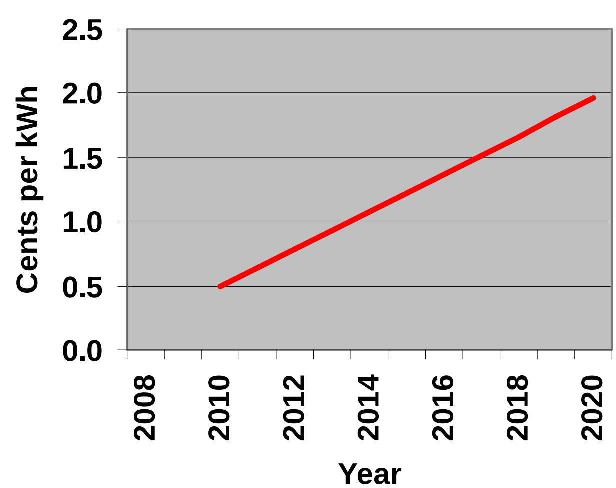


This sector was assumed to escalate at 2.5% per year. The remaining 45% of the electricity cost was assumed to be for power supply costs, which were assumed to escalate at 3% per year, plus an extra amount for expected greenhouse gas emission regulations. Figure 7 depicts the Consultants' estimate of this extra cost adder per kWh in the future. Given the large uncertainty concerning when the extra costs will start and how they will go, a simple trend line was used that reflects a cost penalty of $20 per ton of CO_2 by 2020. This results in an extra 2¢ per kWh for coal-fired generation by the year 2020.

The third bar in Figure 6 shows that the residents in Greensburg will pay a total of $15.5 million to Southern Pioneer for electricity costs and franchise taxes to the City over the next ten years (2008 through 2017), or an average of $1.55 million per year. Nothing was included in the average rate calculations to account for any electric system debt that would be repaid from the City's general fund. Hopefully, all city debt for the electric system will be repaid with the settlement from the insurance company.

FIGURE 7

Power Cost Adder Used for Future Greenhouse Gas Regulations

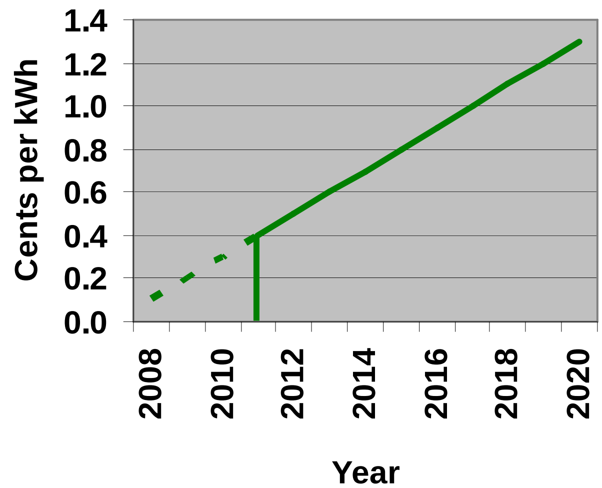


The fourth and fifth bars in Figure 6 represent the amount of financial equity and debt the City would have in the electric system. Since the City would not own the electric system, the equity is zero and it was assumed the insurance settlement would cover the existing debt.

The last green bar at the right in Figure 6 depicts the average percentage of renewable electricity the City would be using over the first ten years. The bar has two segments. The bottom solid green segment represents the percentage of renewable electricity in Sunflower's generating resources. Sunflower currently has about 10% from wind generation, and it was assumed Sunflower would increase that gradually to 20% by 2020 to meet the State's goal. This would have a ten-year average of 12.8%. However, Sunflower has agreed to offer renewable energy credits to Greensburg equal to 100% of its energy purchases for the first 3 years. After that in 2011, it was assumed that the City would purchase renewable energy credits from the market for the balance of the electricity used by the City residents that is not renewable. Figure 8 shows the projected cost of those credits, based on a cost of 0.1¢ per kWh in 2008. Therefore, the franchise tax percentage would be increased upwards starting in 2011 to cover this purchase. By continuing to purchase renewable energy credits, 100% of Greensburg's electricity would be renewable in Strategy 1. Therefore, the top part of the green bar (diagonal striped) represents the additional green renewable energy credits either initially provided by Sunflower or later purchased by the City.

FIGURE 8

Projected Cost of Renewable Energy Credits



Strategy 2 – Retain Electric Utility, No Large Wind Turbine

Under this strategy, the City would decline Southern Pioneer's MOU with the intention of retaining ownership of its electric system. Insurance proceeds would be used to either repair the existing dual-fuel engine generating units or be used to purchase new engine generating units. Again, it was assumed that the insurance proceeds would retire the past debt for engine repairs. No large City-owned wind turbines are included in Strategy 2. However, renewable energy credits are purchased so that all power used in Greensburg is green. This provides a comparable basis for comparing the electric rates for the various strategies, since all strategies provide 100% green power, either by purchasing renewable energy credits or installing local wind generation.

The action steps required include:

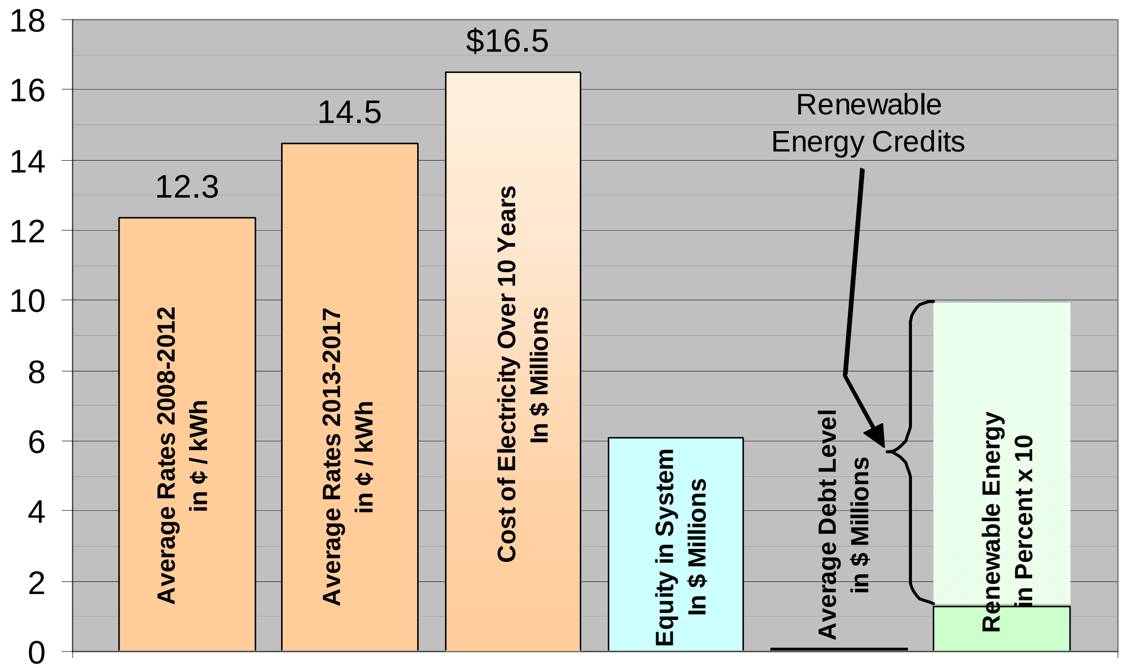
1) Obtain temporary extension of current power supply contract
2) Decline offer from Southern Pioneer and settle up costs as necessary
3) Settle with insurance company for distribution system and generating plant damage
4) Start process for refurbishing existing generating units or replacement by new units
5) Start process to obtain long-term wholesale power supply contract

Table 4 below lists the advantages, disadvantages, risks, and uncertainties for Strategy 2.

TABLE 4 - Strategy 2 – Retain Utility, No Large Wind Turbine Advantages, Disadvantages, Risks, and Uncertainties	
Advantages	City owns local generating plant to keep lights on for long transmission outages
	Electric utility jobs are retained in City
	City has more assets, including a nearly all-new distribution system, which should generate some income for the City and provide financial support for free and discounted services to the City
	City can provide net metering for residents who install PV panels and wind turbines, thus greatly increasing their installation
Disadvantages	Higher electric rates initially for residents and businesses
	City will forgo any net cash gain since it does not sell its electric system
	City will still have to manage its electric system and incur debt for future capital improvements
	No patronage dividends for residents from cooperative
	City will have to purchase renewable energy credits from a third party to make Greensburg greener
Risks and Uncertainties	Electric rates could go higher if the City does not grow back as planned

Figure 9 provides a similar graphical summary of the key financial metrics for this strategy. Again, the left two bars in the chart show the predicted electric rates for the first five-year period to be 12.3¢ per kWh, while the second five-year average would be 14.5¢ per kWh. For the first five years, these projected rates are about 1.3 ¢ higher per kWh than if Southern Pioneer serves the City. However, during the second five years, the cost difference narrows to only 0.4 ¢ per kWh. It is likely that no electric rate increases will be needed for three years.

FIGURE 9 – Financial Summary for Strategy 2 – No Turbines



The City's future electric rates were based on a long-term financial model developed specifically for Greensburg. This financial model was based on Greensburg's historical electric utility costs, and projections of future purchased power costs and operating costs. Cost escalation factors and other assumptions were kept as consistent as possible in the analysis of all of the strategies. Future wholesale power costs were based on a preliminary ballpark estimate provided by the Kansas Power Pool ("KPP") of 4.5 ¢ per kWh postage stamp rate for all power used by Greensburg. Even though KPP utilizes a separate energy charge rate and demand charge rate internally, all of power supply resources are blended together and all KPP members pay for all of their power using a single part rate based on kWh sold. Therefore, a municipal utility with a low load factor will pay the same rate per kWh as does a high load factor utility. Although no financial credit was given to Greensburg for keeping its generating plant, it was assumed the plant would result in lower purchased-power costs over time, based on generating power during peak periods. Transmission service charges were also included. Of course, obtaining a new power supply contract will require some negotiation and an in-depth evaluation. Therefore, there is some uncertainty about which power supplier would eventually supply wholesale power to Greensburg. Nevertheless, the ballpark estimates from KPP were used in this analysis.

The financial model was used to evaluate the impact of the different strategies on the City's electric rates. In order to provide valid comparisons, the electric rates were adjusted for each strategy, so that the electric utility provides the same operating margin for the City (which averages $75,000 annually over the ten years from 2008 through 2017).

A summary of the results of the financial model for Strategies 2 and 3 is included in Attachment 1. Since the City does not have an electric system in Strategy 1, no financial model was developed.

The third bar in Figure 9 shows that the residents in Greensburg would pay a total of $16.5 million to the City for electricity for the next ten years (2008 through 2017), or an average of $1.65 million per year. This 10-year average cost of electricity is 6% higher than Strategy 1 under the MOU. The primary reason the rates are higher under City ownership is due to the ownership and operating costs for the local generating plant. The cost of operating labor, commodities, supplies, and fuel averages about 3¢ for every kWh sold to the City's electric customers. These 6% higher rates under City ownership are at least partly justified by having a local generating plant that can keep the lights on during extended transmission outages. Again, no rate increases would be required for about three years.

The fourth and fifth bars represent the average amount of financial equity and debt the City would have in the electric system over the same ten-year period. The equity was estimated to be $5.7 million, and was assumed to essentially be the difference between depreciated book value and remaining long-term debt. The Consultants estimated today's value of the distribution system to be $4.7 million (nearly all provided by State and FEMA funds for new lines), and the generating plant $2.5 million, after its refurbishment. Although these estimates are rough, fairly conservative, and subject to some judgment, the assumptions and methodology used were consistent for evaluation of all strategies. The average equity over the ten-year period reflects deductions for accumulated depreciation over the period. Again, it was assumed that the insurance settlement would be adequate to retire any existing debt owed by the city for its past electric system improvements.

The last bar at the right depicts the percentage of renewable electricity the City would be using. The actual green power purchased was assumed to be the same 12.8% that was estimated for Sunflower, since the wholesale power provider would also likely try to meet the state's goals of 10% by 2010, and 20% by 2020. Again, to make the comparisons of the strategies comparable, it was assumed that the City would purchase additional renewable energy credits so as to obtain 100% renewable energy. This is shown by the green striped upper part of the bar. Therefore, under Strategy 2, all power used in Greensburg would be green.

Strategy 3 – Retain Electric Utility, Install Large Wind Turbine(s)

Under this strategy, the City would again decline Southern Pioneer's MOU and offer with the intention of retaining ownership of its electric system. The existing engine generating plant would be repaired from insurance proceeds. It was assumed that the insurance proceeds would retire the past debt for engine repairs. Also it was assumed the City would install and own from one to three 1.5 MW wind turbines.

The action steps required include:

1) Obtain temporary extension of current power supply contract
2) Decline offer from Southern Pioneer and settle up costs as necessary
3) Settle with insurance company for distribution system and generating plant damage
4) Start process for refurbishing existing generating units or replacement by new units
5) Start process to obtain long-term wholesale power supply contract that allows for favorable economics for the installation of large wind turbines at Greensburg
6) Work with Southern Pioneer and/or Sunflower as necessary for interconnection of wind turbines to either the distribution or the transmission system
7) Start process of obtaining one or more large wind turbines for installation at Greensburg, and work with corporate benefactors

Table 5 below lists the advantages, disadvantages, risks, and uncertainties for Strategy 3.

TABLE 5 - Strategy 3 – Retain Utility, Install Large Wind Turbine(s)
Advantages, Disadvantages, Risks, and Uncertainties

Advantages	City owns local generating plant to keep lights on for long transmission outages
	Retention of electric utility jobs in City
	City has more assets, including a nearly all-new distribution system, which should generate some income for the City and provide financial support for free and discounted services to the City
	City will own one or more large wind turbines to be located at Greensburg, thereby providing a highly visible sign of the City being green and potentially providing a hedge against higher purchased power costs.
	City can provide net metering for residents who install PV panels and wind turbines, thus greatly increasing their installation
Disadvantages	Higher electric rates for residents and businesses
	City will still have to manage its electric system
	City will likely incur some level of debt if it owns wind generation
	No patronage dividends for residents from cooperative
Risks and Uncertainties	Electric rates could go higher if the City does not grow back as planned
	There are operational risks with wind generation, such as lower wind speeds, lower reliability, and higher repair costs

Strategy 3 includes scenarios for City ownership of one, two, and three 1.5 MW wind turbines. These scenarios would provide wind generation equal to about 35%, 70%, and 100% of the City's projected electricity sales. Although the wind generation could be used to reduce the City's electricity purchases by installing it "behind the meter", this might not be the most cost-effective arrangement, since it will depend upon the wholesale power supplier and the terms of the new wholesale power contract. For example, if Greensburg joins the KPP, Greensburg would buy all of its wholesale power from KPP. Even if the wind turbines were connected behind the meter on the distribution system, Greensburg would purchase an amount of power equal to its total needs, and the amount purchased which would not change if there was one, two, three, or no wind turbines. All wind power generated would be dedicated to the KPP and blended in with all of KPP's other generation resources. KPP would provide load-following services for Greensburg's load and wind generation. With a growing appetite for wind generation, KPP could likely use the output from three 1.5 MW wind turbines installed at Greensburg. Even though the wind power would contractually be dedicated to KPP, the wind power would physically be used locally by Greensburg assuming the wind turbines were connected to the grid at Greensburg.

Attachment 2 includes the results of some simulations for how wind generation might correlate with the City's load over the period of a year. It also shows how much wind generation would be in excess of the City's load, and flow back to the grid if the City had just enough wind generation to provide 100% of its annual energy needs. This would be equivalent to 100% wind generation penetration. Although the results of the simulation are instructive, these results did not affect the economic analysis done in this study.

It was assumed that the City would purchase the wind turbines using proceeds from Clean Renewable Energy Bonds ("CREB"), which have about 15-year terms, with an effective interest rate of zero percent. Although all authorized CREB funds have been committed, it is widely anticipated that Congress will reauthorize more of these funds in 2008 or 2009.

Wind turbines could possibly be procured from the developer of future large wind farms in Kansas so that the project could piggy-back on a larger project to gain some economies of scale. Alternatively, a turbine could possibly be ordered from a smaller niche wind turbine manufacturer, such as Vensys or Americas Wind Energy.

Based on the financial analysis, it was determined some outside gift would likely be required toward the installation of wind generation to keep the City's electric rates from increasing when compared to Strategy 2. Of course the amount needed will depend upon the particular wind turbine model installed, its cost, and the financial arrangement with the wholesale power supplier. In this analysis, the following wind turbine cost assumptions were used:

TABLE 6

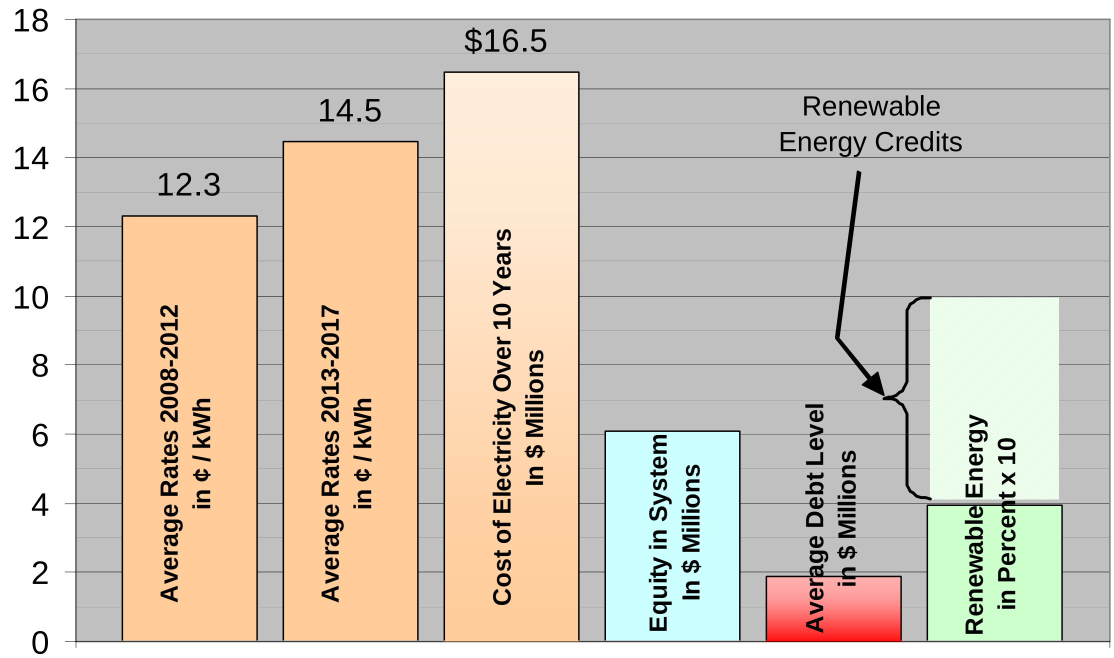
	One Turbine	Two Turbines	Three Turbines
Total Installed MW	1.50	3.00	4.50
Annual Production, Mwh	5,387	10,696	15,926
Installed Cost, $ Millions	$3.30	$6.30	$9.11
Intial Annual O&M Cost	$57,000	$108,300	$153,900

Notes: The "Annual Production" is based on a 77-meter turbine rotor diameter. The "Annual O&M Cost" includes contributions to a long-term Repair and Replacment fund.

In this analysis, the Consultants projected that the wind generation would be sold back to the wholesale power supplier at a constant price of 4.5¢ per kWh, which includes the renewable energy credits. Although this selling price might be a little higher than today's market price for wind power from a large new wind farm, the Consultant believes this selling price is obtainable. With this selling price, a one-turbine project would require an outside gift equal to 5% of the $3.3 million cost, or $165,000. With this size of gift, the City's electric rates would likely not be increased, compared to Strategy 2 that has no wind generation but purchase of 100% renewable energy credits.

Figure 10 provides a similar graphical summary of the key financial metrics for this Strategy 3 with one wind turbine. Again, the left three bars in the chart show the predicted electric rates and total cost of electricity to be the same as Strategy 2 without any wind generation. This proves that a gift equal to 5% of the wind turbine's cost would allow the installation of one wind turbine without increasing electric rates compared to simply purchasing renewable energy credits in Strategy 2. These projected electric rates are still about 6% higher per kWh than if Southern Pioneer served the City. Again, the electric rates are higher primarily because the City maintains the local generating plant to keep the lights on for extended transmission outages. As with Strategy 2, no electric rate increases are projected for about three years.

FIGURE 10 – Financial Summary for Strategy 3 – One Turbine
City Installs a 1.5 MW Wind Turbine and Receives a 5% Financial Gift



Again, the fourth and fifth bars represent the average amount of financial equity and debt the City would have in the electric system over the ten-year period. With the addition of a wind turbine, the equity increases slightly to $6.0 million while the debt goes up to $2.0 million respectively.

The last bar at the right indicates that the single wind turbine would generate 39% of the City's annual usage for a normal wind speed year. This would likely be the highest percentage of wind generation for any city in the U.S. To keep the comparison of the various strategies comparable, it was again assumed that the City would purchase additional renewable energy credits so as to provide 100% green power.

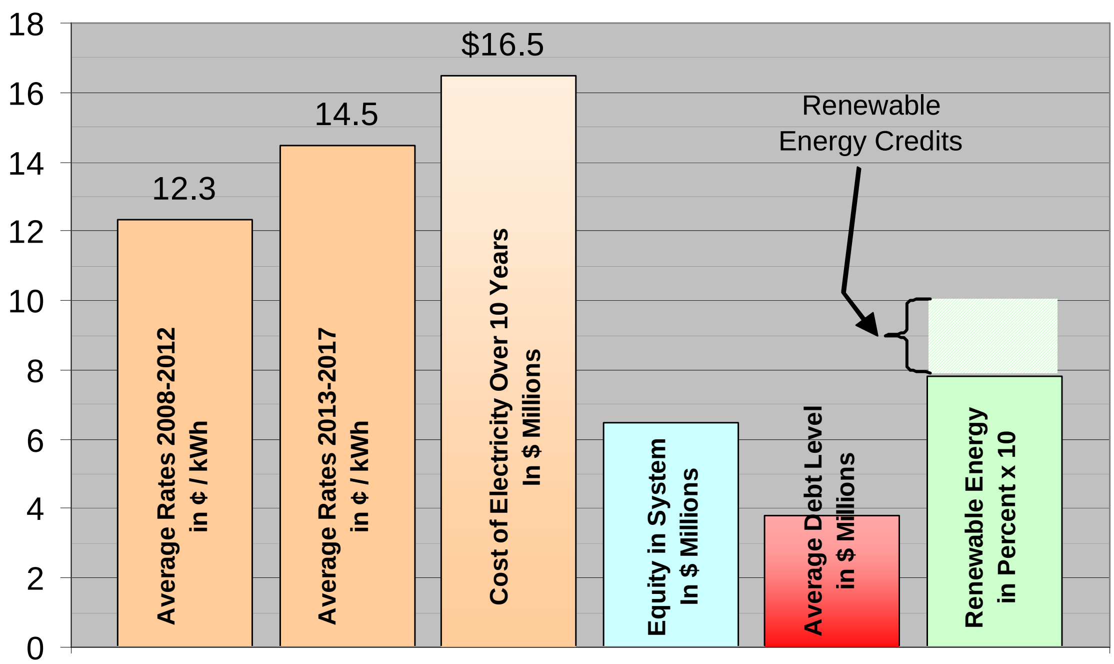
If no financial gift is received and the City pays the full $3.3 million cost for one wind turbine, the City's electric rates would be about the same during the first five years, but about 0.1¢ per kWh on average higher for the second five-year period and beyond, making the average over 10 years 7% higher (instead of 6% higher) than Strategy 1 with the MOU. Therefore, if the City goes it alone on a single wind turbine, its rates would be about 7% higher than under the MOU.

Likewise, a financial gift larger than 5% would tend to reduce the City's electric rates. For example, a gift equal to about 40% of the installed cost of one turbine, or $1.32 million, would result in electric rates that over the long run would be comparable to those under Strategy 1 with the MOU. Of course, if the selling price for the wind power is higher than 4.5¢ per kWh, the economics would improve slightly. For example if the selling price is 5.0¢ per kWh for a single turbine, the electric rates over the long run would be about 3% higher than Strategy 1 with the MOU.

The real economic benefits of wind generation accrue once the debt has been repaid. In this analysis, once the 15-year-term CREB financing is repaid, the profit from ownership of one 1.5 MW wind turbine would allow all rates to drop by about 1.3¢ per kWh. Likewise, ownership of 3 turbines would allow rates to be 4¢ per kWh after the debt is repaid.

A second scenario with two 1.5 MW wind turbines was also analyzed. Figure 11 shows the results of this scenario. No financial gift was required to keep the City's electric rates the same as for Strategy 2 with no wind turbines. The slightly improved economies of scale with a larger two turbine project resulted in no need for a gift. Again this Strategy 3 with two turbines still results in electric rates being 6% higher than Strategy 1 with the MOU. No electric rate increases are projected for three years.

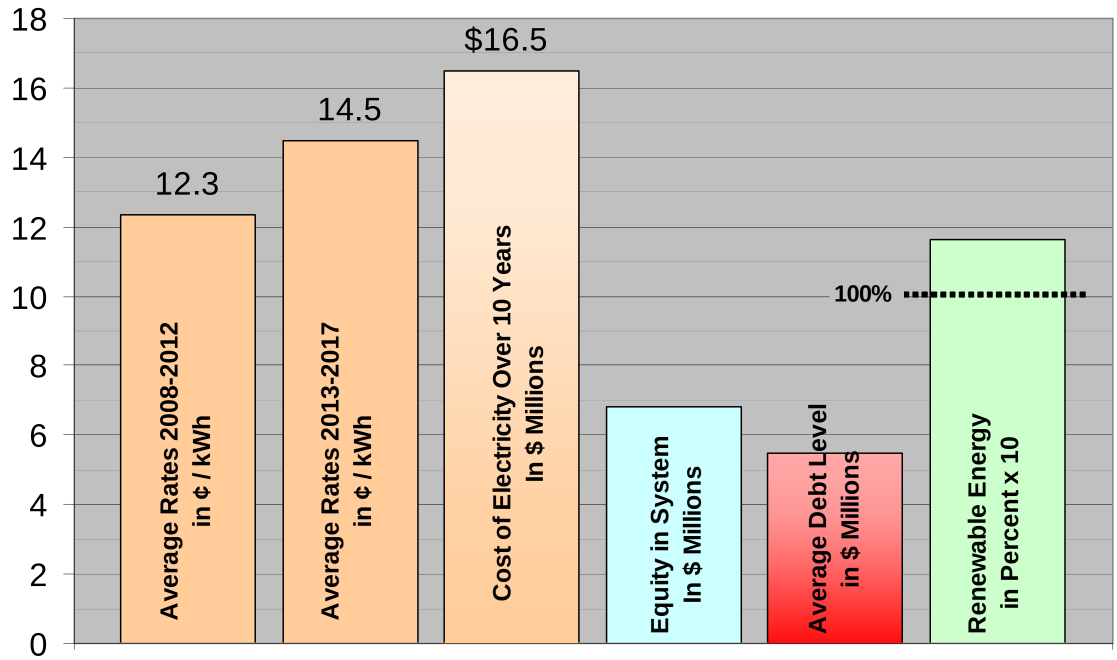
FIGURE 11 – Financial Summary for Strategy 3 – Two Turbines
City Installs Two 1.5 MW Wind Turbines and Receives No Financial Gift



As would be expected, the equity and debt levels increase with two wind turbines, as shown by the fourth and fifth bars in Figure 11 above. The two turbines would generate 78% of the City's electricity needs during the first ten years of operation (2009-2018). Renewable energy credits were purchased for the remaining 22% of energy needs so as to provide 100% green energy to the City.

A third scenario with three 1.5 MW wind turbines was also analyzed. Under this scenario, the turbines would generate about 16% more energy than would be used by the City during the first 10 years of operation. Figure 12 illustrates the results of the financial analysis. Again, no financial gift was needed to keep the rates the same as Strategy 2 with no wind turbine and no electric rate increases are required for three years.

FIGURE 12 – Financial Summary for Strategy 3 – Three Turbines
City Installs Three 1.5 MW Wind Turbines and Receives No Financial Gift



The debt level again increases to $5.5 million. Of course, any financial gift would reduce the City's debt requirements. The green bar in Figure 12 shows that three wind turbines provide 116% of the City's needs. Therefore installing three 1.5 MW wind turbines would essentially allow the City to get all of its power from wind generation. Of course, there would be many times when the City uses more power than the wind turbines would generate; resulting in the use of grid power, which primarily comes from coal-fired power plants. However, there would be many other hours where the wind turbines generate more power than the City would use, with the excess going out to the grid to displace other coal-fired generation. Over the course of the year, the turbines would generate more wind power than the City needed, thus making the City 100+% supplied by wind power.

Table 7 provides a comparison and summary of the analysis in this study.

TABLE 7
Comparison of Strategies

	Strategy 1 MOU	Strategy 2 - Retain Utility But No Turbine		Strategy 3 – Retain Utility and Add Wind Generation			
		No Purchase of R.E. Credits	Purchase R.E. Credits	1.5 MW Wind		3.0 MW Wind No Gift	4.5 MW Wind No Gift
				No Gift	5% Gift ($165,000)		
Figure Number in Report	Figure 6	-	Figure 9	-	Figure 10	Figure 11	Figure 12
Attachment 1 Printout Summary	-	-	Summary 1	Summary 2		Summary 3	Summary 4
Avg. Electric Rates for 2008-2012	11.0 ¢	12.2 ¢	12.3 ¢	12.3 ¢	12.3 ¢	12.3 ¢	12.3 ¢
Avg. Electric Rates for 2013-2017	14.1 ¢	13.7 ¢	14.5 ¢	14.6 ¢	14.5 ¢	14.5 ¢	14.5 ¢
Avg. Annual Electricity Cost	$1.55 mil.	$1.59 mil.	$1.65 mil.	$1.66 mil.	$1.65 mil.	$1.65 mil.	$1.65 mil.
Comparison of Rates, 2008-2017	Reference	+ 3 %	+ 6 %	+ 7 %	+ 6 %	+ 6 %	+ 6 %
Average Equity (2008-2017)	-	$5.7 mil.	$5.7 mil.	$6.1 mil.	$6.0 mil.	$6.5 mil.	$6.8 mil.
Average Debt (2008-2017)	-	-	-	$2.0 mil.	$1.9 mil.	$3.8 mil.	$5.5 mil.
Renew. Energy Purch. (10 Yr. Avg)	12.8%	12.8%	12.8%	39%	39%	78%	116%
Renew. Energy Credits Purchased	87.2%	-	87.2%	61%	61%	22%	0%
Total Renew. Purchases + Credits	100%	12.8%	100%	100%	100%	100%	116%
Probability of One or More Lengthy Power Outages in the Future	High	Low	Low	Low	Low	Low	Low
Probability of Having at Least One Large Wind Turbine at Greensburg	Medium	-	-	Highest	High	Medium	Medium

Observations and Conclusions

The table on previous page summarizes the key findings in this analysis. Based on the analysis in this study, the following observations can be made:

If the City accepts Southern Pioneer's MOU (Strategy 1)

- Electric rates in the City will initially average about 1.3¢ per kWh less expensive than they would be under City ownership. The savings narrows to around 0.5¢ per kWh over the longer run. These projected rates are based on a 10% City electric franchise tax.
- The City would likely have a net cash gain from the sale of its electric system.

If the City retains ownership of its electric system but does not install a wind turbine (Strategy 2)

- Electric rates will likely stay the same for about three years. After that, rates might increase an average of 3.5% per year to allow continuation of a modest annual net margin of about $75,000 per year to the City. On average, rates would be about 6% higher than Strategy 1 with the MOU. This is based on purchasing renewable energy credits to provide 100% green power. Also, the projected rates will depend upon the terms of the new wholesale power supply contract.
- The higher electric rates are due in part to owning, maintaining, and operating the local generating plant, which should effectively limit the length of outages due to transmission line problems.
- The higher rates are also due partly to the free and discounted services now provided by the electric utility to the City and its residents. These services include street lighting, free electricity for some city facilities, and contributions of labor and time by electric utility employees.

If the City retains ownership of its electric system and installs one or more wind turbines (Strategy 3)

- Installing one 1.5 MW wind turbine without any financial gift would tend to make electric rates about 7% higher than Strategy 1, or only 1% higher than Strategy 2. A modest 5% financial gift would make electric rates the same as Strategy 2. Again, it is projected that no increase in electric rates would be needed for three years.
- There is likely no need for higher rates to install either two or three 1.5 MW wind turbines when compared to having no wind turbines in Strategy 2. Again electric rates will likely stay the same for about three years with average annual increases of 3.5% thereafter. On average, rates would be about 6% higher than Strategy 1 with the MOU or essentially the same as Strategy 2. These rate impacts are based on a new wholesale power supply contract similar to that used in the KPP, which would likely allow the installation of two or three wind turbines at Greensburg.
- Three 1.5 MW wind turbines at Greensburg would make the City 100+% supplied by wind power.

The observations are based on the following key assumptions used in the analysis:

1) An insurance settlement that will allow the refurbishment or replacement of the engine generation power plant and retirement of all existing electric utility bonds
2) A wholesale power supply contract:
   a. with a postage stamp rate of about 4.5¢ per kWh and no demand charge
   b. that would accommodate local wind generation by providing load following service for both load and wind generation
   c. that would accommodate the sale of Greensburg's local wind generation for 4.5 ¢ per kWh, which includes the renewable energy credits.
3) Availability of large wind turbines with an installation cost of $2,200 to $2,000 per kW.
4) The ability of Greensburg to sell zero interest Clean Renewable Energy Bonds to finance 100% of the cost of any wind turbines
5) Continued growth in Greensburg's electricity needs to a level of 13.3 million kWh per year, which is 80% more than used in 2007.
6) No consideration was given in the financial analysis to any net cash gain from selling the electric system to Southern Pioneer. A large net cash gain would of course be beneficial to the City and could be used for investment in a wind turbine, perhaps in conjunction with other investors. The power could be sold to Sunflower or other wholesale power suppliers

Using a corporate partner for a wind turbine project may result in slightly lower wind power costs than used in this analysis, depending upon the rate or return requirements of the corporate partner. Such a scenario would of course improve the economics and further reduce the need to increase electric rates in the future.

If the City serves a 4 MW high load factor biodiesel production facility in the future, the economics of adding wind generation would likely be comparable to that found in this study. However, the existing transmission system might not be able to accommodate enough wind turbines to provide 100% wind power for the larger City load without some transmission system reinforcements. A detailed transmission study would be required to determine the need for any system reinforcements.

Given this analysis and these observations, the Consultants have made the following conclusions:

- To avoid having lengthy power outages due to transmission line outages, the City should retain its electric generating plant. This would be most practical if the City also retained ownership of its electric system. Therefore, the City should not accept the MOU.
- Electric rates will average about 6% higher under Strategy 2 with City ownership of the electric utility compared to retail electric service from Southern Pioneer. No electric rate increases would likely be required for about three years and renewable energy credits would be purchased to provide 100% green power.
- With the electric system under City ownership, the installation of one 1.5 MW wind turbine would make rates average about 7% higher than under Strategy 1 with the MOU. One wind turbine would provide an average of about 39% of the City's electricity needs.

A modest gift of $165,000 would make the electric rates about the same as Strategy 2, with no wind turbines.

- Installing two or three 1.5 MW wind turbines would not result in higher rates than having no wind turbines (Strategy 2). Two wind turbines would provide 78% of the City's electricity needs, while 3 turbines would provide 116% of the City's needs.
- Since the installation of large wind turbines has little impact on electricity rates, Greensburg should consider the ownership and installation of wind turbines at or near the City.

Thomas A. Wind, PE
Wind Utility Consulting, PC
January 15, 2008

Attachment 1
Summary of Financial Analysis

This attachment includes the power supply and financial model printouts for on a year-by-year basis for the continued operation of the Greensburg electric system. Although these models are preliminary in nature, they were used for the analysis in this report.

There are eight pages of printouts for each scenario and the following four scenarios are included:

Summary 1 - Strategy 2 - Retain Utility, But No Wind Generation

Summary 2 - Strategy 3 – Retain Utility, 1.5 MW of Wind Generation with No Financial Gift

Summary 3 - Strategy 3 – Retain Utility, 3.0 MW of Wind Generation with No Financial Gift

Summary 4 - Strategy 3 – Retain Utility, 4.5 MW of Wind Generation with No Financial Gift

Summary 1

Strategy 2

Retain Utility

But No Wind Generation

	A	B	C	D	E	F	G	H	I	J
1	**Strategy 2: Retain Utility, No**	**Summary of Power Supply and Financial Modeling for Greensburg**								
2	**Wind, 100% Green Power**	**Preliminary and Confidential**								
3			**YEAR >>**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
4	**Load, Peak, Energy Prices**									
5	Peak Load			0	4,489	0	2,479	3,360	3,444	3,478
6	Storage System Losses, MWH			0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH			15,622	15,474	7,414	9,496	12,867	13,189	13,321
8										
9	Natural Gas Cost $ / MMBTU					$7.00	$7.50	$7.80	$8.11	$8.44
10	Biodiesel Cost, $ / Gal					$2.50	$2.60	$2.70	$2.81	$2.92
11	Diesel Cost, $ / Gal					$2.75	$2.86	$2.97	$3.09	$3.22
12										
13	**Wind Generation**									
14	Wind Generation, Number of Turbines							0	0	0
15	Wind Generation, MW	1.50 Turbine Size, in MW			0.0% Capital Contribution, Gift =			0.00	0.00	0.00
16	Wind Generation, MWH	41.0% Annual Capacity Factor Used				-0.30% Array Delta		0	0	0
17	Wind Generation Capital Cost, $	1	2	3	4	< # of WTs		$0	$0	$0
18	Wind Generation O&M	$2,200	$2,100	$2,025	$1,975	< Total Cost per kW		$0	$0	$0
19	Wind Generation R&R & Warranty	$12	$ / kW in 2009		$26	$ / kW in 2009		$0	$0	$0
20										
21	Wind Generation as a % of Total Load							0.0%	0.0%	0.0%
22	Excess Wind Gen to Grid, %							0.0%	0.0%	0.0%
23	Excess Wind Gen to Grid, MWh							0	0	0
24										
25	**Energy Storage System**									
26	Energy Storage, MW			0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $			$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $			$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed			0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered			0	0	0	0	0	0	0
32	Energy Storage MWH Lost			0	0	0	0	0	0	0
33										
34	**Purchases & Sales**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
35	Purchases from Grid			14,823	15,296	7,364	8,846	12,217	12,539	12,671
36	Wind Power Sold to Grid						0	0	0	0
37	Equivalent Net Purchases (Sales to Grid)			14,823	15,296	7,364	8,846	12,217	12,539	12,671
38							0.0%	94.9%	95.1%	95.1%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH						$45.0	$46.4	$47.7	$49.2
41	Climate Change Costs, $/MWH	Based on TAW 3 Scenario					$0.00	$0.00	$4.89	$6.36
42										
43	Integration Costs	260,000	MWh Pool Base				$0.0	$0.0	$0.0	$0.0
44	Purchased Energy, Dollars			$800,462	$769,694	$371,610	$398,086	$566,279	$659,971	$703,656
45	Cost of Renewable Energy Credits						$8,547	$23,161	$35,611	$47,423
46	Purchased Demand, in kW						2,479	3,360	3,444	3,478
47	Demand Charge Rate, $ / kW-Month						$0.00	$0.00	$0.00	$0.00
48	Demand Charges						$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	J
49	Total Cost of Purchased Power & REC's, Dollars			$857,584	$701,754	$371,610	$406,633	$589,440	$695,582	$751,079
50	Transmission Service						$60,000	$83,332	$87,551	$90,638
51				$57.85	$45.88	$50.46	$45.97	$48.25	$55.47	$59.27
52	Total Cost of Purchased Power, $ / Mwh									
53	Rate for Sale of Excess Wind Power	$45.00	per Mwh	0.0%	Escalator		$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power						$0	$0	$0	$0
55	Revenue from Sale of RECs	$0.00	per Mwh	0.0%	Escalator		$0	$0	$0	$0
56										
57	**Engine Plant**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
58	Existing Engine Generating Capacity			6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity			0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW			$0	$0	$0	$750	$773	$796	$820
61	New Engine Total Capital Cost, $			$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**			2005	2006	2007	1/2 Year	2009	2010	2011
65	Energy Generated by Engines, MWh			799	178	50	650	650	650	650
66	Percentage from Natural Gas			0.0%	0.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel			0%	0%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel			0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $			$ 69,539	$ 104,645	$ 10,395	$ 49,500	$ 51,480	$ 53,539	$ 55,681
71	Diesel Cost, $ as pilot fuel for gas			$ 14,093	$ -	$ 3,312	$ 17,223	$ 17,912	$ 18,628	$ 19,373
72	Biodiesel Cost, $ as pilot or replacement for gas			$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $			$ 83,632	$ 104,645	$ 13,707	$ 66,723	$ 69,392	$ 72,167	$ 75,054
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services			$ 206,081	$ 193,952	$ 120,010	$ 123,610	$ 127,319	$ 131,138	$ 135,072
77	Existing Plant Contractual Services			$ 171,345	$ 102,954	$ 54,860	$ 141,264	$ 145,502	$ 149,867	$ 154,363
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services			$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services			0	0	0	0	0	0	0
82										
83	**Cash receipts**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
84	Sales			$1,609,787	$1,791,549	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
85	Rentals			$0	$0	$0	$0	$0	$0	$0
86	Security Lights			$3,458	$4,218	$1,963	$2,514	$3,407	$3,492	$3,703
87	Service Charge			$1,328	$1,668	$776	$994	$1,347	$1,381	$1,464
88	Materials sold			$0	$3,335	$1,718	$1,769	$1,822	$1,877	$1,933
89	Other			$185	$96	$145	$149	$154	$158	$163
90	Wind Power & REC Sales			$0	$0	$0	$0	$0	$0	$0
91	Total cash receipts			$1,614,758	$1,800,866	$838,283	$1,073,242	$1,453,607	$1,489,972	$1,580,054
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services			$206,081	$193,952	$120,010	$123,610	$127,319	$131,138	$135,072
95	Engine Plant Contractual Services			$171,345	$102,954	$54,860	$141,264	$145,502	$149,867	$154,363
96										
97	Wind Generator O&M, R&R						$0	$0	$0	$0
98	Commodities			$14,969	$17,726	$16,838	$17,343	$17,863	$18,399	$18,951

	A	B	C	D	E	F	G	H	I	J
99	Diesel fuel & oil			$14,093	$0	$4,741	$8,533	$17,066	$17,578	$18,105
100	Electricity, RECs, & Transmission Service			$857,584	$701,754	$371,610	$466,633	$672,772	$783,133	$841,717
101	Natural Gas			$69,539	$104,645	$10,395	$49,500	$51,480	$53,539	$55,681
102	Capital outlay			$89	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services			$158,841	$155,983	$162,134	$166,998	$172,008	$177,169	$182,484
105	Contractual Services			$13,493	$8,817	$11,490	$11,834	$12,189	$12,555	$12,932
106	Commodities			$41,809	$47,408	$45,947	$47,325	$48,745	$50,207	$51,713
107	Capital outlay			$0	$3,984	$2,052	$2,113	$2,177	$2,242	$2,309
108	**General & Administrative**									
109	Contractual Services			$2,644	$2,835	$2,822	$2,906	$2,994	$3,083	$3,176
110	Commodities			$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**			$175,758	$175,758	$0	$0	$0	$0	$0
112	**Reimbursed expenditures**			($9,928)	($4,315)	($7,335)	($7,555)	($7,782)	($8,015)	($8,256)
113	**Total Expenditures**			$1,716,317	$1,511,501	$795,562	$1,030,505	$1,262,333	$1,390,895	$1,468,247
114										
115	Receipts over (under) expenditures			($101,559)	$289,365	$42,721	$42,737	$191,274	$99,077	$111,807
116	Unencumbered cash (deficit) BOY			$9,040	($92,519)	$196,846	$189,546	$189,546	$294,008	$304,101
117	Trasfer to City			$0	$0	($50,021)	($42,737)	($86,813)	($88,984)	($94,367)
118	Unencumbered cash (deficit), EOY			($92,519)	$196,846	$189,546	$189,546	$294,008	$304,101	$321,540
119										
120	**Retail Sales by Class**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
121										
122	Residential Mwh			10,338	9,533	4,773	6,113	8,284	8,491	8,576
123	Commercial Mwh			4,303	4,288	2,122	2,718	3,683	3,775	3,813
124	Furnished without charges & Losses			981	1,653	519	665	901	923	932
125	Total Mwh to System			15,622	15,474	7,414	9,496	12,867	13,189	13,321
126	Losses as a % of Sales			6.7%	12.0%	10.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.0%
129	Residential Cost per kWh			$0.1115	$0.1216	$0.1216	$0.1216	$0.1216	$0.1216	$0.1277
130	Commercial Cost per kWh			$0.1106	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1254
131	Residential Revenue			$1,153,000	$1,159,000	$580,292	$743,262	$1,007,112	$1,032,300	$1,094,754
132	Commercial Revenue			$476,000	$512,000	$253,391	$324,553	$439,766	$450,765	$478,036
133	Total Sales Revenue			$1,629,000	$1,671,000	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
134	Average Retail Sales Revenue ¢ per kWh			11.13	12.09	12.09	12.09	12.09	12.09	12.70
135	Residential Customers			792	783					
136	Commercial Customers			132	148					
137										
138	**Simplified Balance Sheet**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
139	Distribution System - New Investment					$4,500,000	$0	$0	$0	$0
140	Cumulative Investment			Existing Distribution that Survived>	$250,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation					$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation					$142,500	$285,000	$427,500	$570,000	$712,500
143	Net Depreciated Investment					$4,607,500	$4,465,000	$4,322,500	$4,180,000	$4,037,500
144										
145	Production Plant - New Investment					$0	$0	$0	$0	$0
146	Cumulative Investment			Existing Diesel Plant >	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000
147	Annual Depreciation					$100,000	$100,000	$100,000	$100,000	$100,000
148	Accumulated Depreciation					$100,000	$200,000	$300,000	$400,000	$500,000

	A	B	C	D	E	F	G	H	I	J
149	Net Depreciated Investment					$2,400,000	$2,300,000	$2,200,000	$2,100,000	$2,000,000
150										
151	Total Utility Plant					$7,250,000	$7,250,000	$7,250,000	$7,250,000	$7,250,000
152	Less Accumulated Depreciation					$242,500	$485,000	$727,500	$970,000	$1,212,500
153	Total Net Utility Plant					$7,007,500	$6,765,000	$6,522,500	$6,280,000	$6,037,500
154	Current Assets & Other					$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets					$7,107,500	$6,865,000	$6,622,500	$6,380,000	$6,137,500
156										
157	Total Equity					$7,057,500	$6,815,000	$6,572,500	$6,330,000	$6,087,500
158	Long-Term Liabilities					$0	$0	$0	$0	$0
159	Current Liabilities					$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities					$50,000	$50,000	$50,000	$50,000	$50,000
161	Total Liabilities & Equity					$7,107,500	$6,865,000	$6,622,500	$6,380,000	$6,137,500

	K	L	M	N	O	P	Q	R	S	T
1	**Strategy 2: Retain Utility, No**	**Summary of Power Supply and Financial Modeling for Greensburg**								
2	**Wind, 100% Green Power**	**Preliminary and Confidential**								
3		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
4	**Load, Peak, Energy Prices**									
5	Peak Load	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
6	Storage System Losses, MWH	0	0	0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
8										
9	Natural Gas Cost $ / MMBTU	$8.77	$9.12	$9.49	$9.87	$10.26	$10.67	$11.10	$11.55	$12.01
10	Biodiesel Cost, $ / Gal	$3.04	$3.16	$3.29	$3.42	$3.56	$3.70	$3.85	$4.00	$4.16
11	Diesel Cost, $ / Gal	$3.35	$3.48	$3.62	$3.76	$3.91	$4.07	$4.23	$4.40	$4.58
12										
13	**Wind Generation**									
14	Wind Generation, Number of Turbines	0	0	0	0	0	0	0	0	0
15	Wind Generation, MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	Wind Generation, MWH	0	0	0	0	0	0	0	0	0
17	Wind Generation Capital Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind Generation O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Wind Generation R&R & Warranty	$0	$0	$0	$0	$0	$0	$0	$0	$0
20										
21	Wind Generation as a % of Total Load	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	Excess Wind Gen to Grid, %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	Excess Wind Gen to Grid, MWh	0	0	0	0	0	0	0	0	0
24										
25	**Energy Storage System**									
26	Energy Storage, MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed	0	0	0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered	0	0	0	0	0	0	0	0	0
32	Energy Storage MWH Lost	0	0	0	0	0	0	0	0	0
33										
34	**Purchases & Sales**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
35	Purchases from Grid	12,804	12,939	13,075	13,212	13,351	13,491	13,632	13,775	13,919
36	Wind Power Sold to Grid	0	0	0	0	0	0	0	0	0
37	Equivalent Net Purchases (Sales to Grid)	12,804	12,939	13,075	13,212	13,351	13,491	13,632	13,775	13,919
38		95.2%	95.2%	95.3%	95.3%	95.4%	95.4%	95.4%	95.5%	95.5%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH	$50.6	$52.2	$53.7	$55.3	$57.0	$58.7	$60.5	$62.3	$64.2
41	Climate Change Costs, $/MWH	$7.83	$9.29	$10.76	$12.23	$13.70	$15.16	$16.63	$18.10	$19.57
42										
43	Integration Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
44	Purchased Energy, Dollars	$748,733	$795,249	$843,251	$892,789	$943,915	$996,683	$1,051,148	$1,107,367	$1,165,401
45		$59,199	$70,934	$82,623	$94,262	$105,845	$117,368	$128,824	$140,210	$151,519
46	Purchased Demand, in kW	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
47	Demand Charge Rate, $ / kW-Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
48	Demand Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0

	K	L	M	N	O	P	Q	R	S	T
49	Total Cost of Purchased Power & REC's, Dollars	$807,932	$866,183	$925,874	$987,051	$1,049,760	$1,114,051	$1,179,972	$1,247,578	$1,316,921
50	Transmission Service	$93,833	$97,140	$100,564	$104,109	$107,779	$111,578	$115,511	$119,583	$123,799
51	Total Cost of Purchased Power, $ / Mwh	$63.10	$66.94	$70.81	$74.71	$78.63	$82.58	$86.56	$90.57	$94.61
52										
53	Rate for Sale of Excess Wind Power	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power	$0	$0	$0	$0	$0	$0	$0	$0	$0
55	Revenue from Sale of RECs	$0	$0	$0	$0	$0	$0	$0	$0	$0
56										
57	**Engine Plant**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
58	Existing Engine Generating Capacity	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW	$844	$869	$896	$922	$950	$979	$1,008	$1,038	$1,069
61	New Engine Total Capital Cost, $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**	2012	2013	2014	2015	2016	2017	2018	2019	2020
65	Energy Generated by Engines, MWh	650	650	650	650	650	650	650	650	650
66	Percentage from Natural Gas	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel	10%	10%	10%	10%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel	0%	0%	0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $	$ 57,908	$ 60,224	$ 62,633	$ 65,139	$ 67,744	$ 70,454	$ 73,272	$ 76,203	$ 79,251
71	Diesel Cost, $ as pilot fuel for gas	$ 20,148	$ 20,954	$ 21,792	$ 22,664	$ 23,570	$ 24,513	$ 25,494	$ 26,513	$ 27,574
72	Biodiesel Cost, $ as pilot or replacement for gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $	$ 78,056	$ 81,178	$ 84,425	$ 87,802	$ 91,315	$ 94,967	$ 98,766	$ 102,716	$ 106,825
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services	$ 139,124	$ 143,298	$ 147,597	$ 152,025	$ 156,586	$ 161,283	$ 166,122	$ 171,105	$ 176,239
77	Existing Plant Contractual Services	$ 158,994	$ 163,764	$ 168,677	$ 173,737	$ 178,949	$ 184,317	$ 189,847	$ 195,542	$ 201,409
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services	$0	$0	$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services	0	0	0	0	0	0	0	0	0
82										
83	**Cash receipts**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
84	Sales	$1,588,518	$1,716,712	$1,733,879	$1,891,315	$1,910,228	$2,083,677	$2,104,514	$2,125,559	$2,146,815
85	Rentals	$0	$0	$0	$0	$0	$0	$0	$0	$0
86	Security Lights	$3,740	$4,042	$4,082	$4,453	$4,497	$4,906	$4,955	$5,004	$5,054
87	Service Charge	$1,479	$1,598	$1,614	$1,761	$1,778	$1,940	$1,959	$1,979	$1,999
88	Materials sold	$1,991	$2,051	$2,112	$2,176	$2,241	$2,308	$2,377	$2,449	$2,522
89	Other	$168	$173	$178	$183	$189	$194	$200	$206	$213
90	Wind Power & REC Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
91	Total cash receipts	$1,595,896	$1,724,576	$1,741,866	$1,899,888	$1,918,934	$2,093,025	$2,114,006	$2,135,197	$2,156,602
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services	$139,124	$143,298	$147,597	$152,025	$156,586	$161,283	$166,122	$171,105	$176,239
95	Engine Plant Contractual Services	$158,994	$163,764	$168,677	$173,737	$178,949	$184,317	$189,847	$195,542	$201,409
96										
97	Wind Generator O&M, R&R	$0	$0	$0	$0	$0	$0	$0	$0	$0
98	Commodities	$19,520	$20,105	$20,709	$21,330	$21,970	$22,629	$23,308	$24,007	$24,727

	K	L	M	N	O	P	Q	R	S	T
99	Diesel fuel & oil	$18,648	$19,208	$19,784	$20,377	$20,989	$21,618	$22,267	$22,935	$23,623
100	Electricity, RECs, & Transmission Service	$901,765	$963,323	$1,026,438	$1,091,160	$1,157,540	$1,225,629	$1,295,484	$1,367,161	$1,440,719
101	Natural Gas	$57,908	$60,224	$62,633	$65,139	$67,744	$70,454	$73,272	$76,203	$79,251
102	Capital outlay	$0	$0	$0	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services	$187,958	$193,597	$199,405	$205,387	$211,549	$217,895	$224,432	$231,165	$238,100
105	Contractual Services	$13,320	$13,719	$14,131	$14,555	$14,991	$15,441	$15,904	$16,381	$16,873
106	Commodities	$53,265	$54,863	$56,509	$58,204	$59,950	$61,749	$63,601	$65,509	$67,474
107	Capital outlay	$2,379	$2,450	$2,523	$2,599	$2,677	$2,757	$2,840	$2,925	$3,013
108	**General & Administrative**									
109	Contractual Services	$3,271	$3,369	$3,470	$3,574	$3,682	$3,792	$3,906	$4,023	$4,144
110	Commodities	$0	$0	$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**	$0	$0	$0	$0	$0	$0	$0	$0	$0
112	**Reimbursed expenditures**	($8,503)	($8,759)	($9,021)	($9,292)	($9,571)	($9,858)	($10,154)	($10,458)	($10,772)
113	**Total Expenditures**	$1,547,648	$1,629,162	$1,712,855	$1,798,795	$1,887,055	$1,977,707	$2,070,829	$2,166,499	$2,264,800
114										
115	Receipts over (under) expenditures	$48,248	$95,414	$29,011	$101,093	$31,879	$115,318	$43,177	($31,302)	($108,197)
116	Unencumbered cash (deficit) BOY	$321,540	$321,540	$321,540	$321,540	$321,540	$321,540	$321,540	$321,540	$290,239
117	Trasfer to City	($48,248)	($95,414)	($29,011)	($101,093)	($31,879)	($115,318)	($43,177)	$0	$0
118	Unencumbered cash (deficit), EOY	$321,540	$321,540	$321,540	$321,540	$321,540	$321,540	$321,540	$290,239	$182,042
119										
120	**Retail Sales by Class**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
121										
122	Residential Mwh	8,662	8,748	8,836	8,924	9,013	9,103	9,194	9,286	9,379
123	Commercial Mwh	3,851	3,890	3,928	3,968	4,007	4,047	4,088	4,129	4,170
124	Furnished without charges & Losses	942	951	961	970	980	990	1,000	1,010	1,020
125	Total Mwh to System	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
126	Losses as a % of Sales	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year	0.0%	7.0%	0.0%	8.0%	0.0%	8.0%	0.0%	0.0%	0.0%
129	Residential Cost per kWh	$0.1277	$0.1366	$0.1366	$0.1475	$0.1475	$0.1593	$0.1593	$0.1593	$0.1593
130	Commercial Cost per kWh	$0.1254	$0.1341	$0.1341	$0.1449	$0.1449	$0.1565	$0.1565	$0.1565	$0.1565
131	Residential Revenue	$1,105,702	$1,194,932	$1,206,881	$1,316,466	$1,329,631	$1,450,361	$1,464,865	$1,479,513	$1,494,309
132	Commercial Revenue	$482,817	$521,780	$526,998	$574,849	$580,598	$633,316	$639,649	$646,045	$652,506
133	Total Sales Revenue	$1,588,518	$1,716,712	$1,733,879	$1,891,315	$1,910,228	$2,083,677	$2,104,514	$2,125,559	$2,146,815
134	Average Retail Sales Revenue ¢ per kWh	12.70	13.58	13.58	14.67	14.67	15.84	15.84	15.84	15.84
135	Residential Customers									
136	Commercial Customers									
137										
138	**Simplified Balance Sheet**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
139	Distribution System - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
140	Cumulative Investment	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation	$855,000	$997,500	$1,140,000	$1,282,500	$1,425,000	$1,567,500	$1,710,000	$1,852,500	$1,995,000
143	Net Depreciated Investment	$3,895,000	$3,752,500	$3,610,000	$3,467,500	$3,325,000	$3,182,500	$3,040,000	$2,897,500	$2,755,000
144										
145	Production Plant - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
146	Cumulative Investment	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000
147	Annual Depreciation	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
148	Accumulated Depreciation	$600,000	$700,000	$800,000	$900,000	$1,000,000	$1,100,000	$1,200,000	$1,300,000	$1,400,000

	K	L	M	N	O	P	Q	R	S	T
149	Net Depreciated Investment	$1,900,000	$1,800,000	$1,700,000	$1,600,000	$1,500,000	$1,400,000	$1,300,000	$1,200,000	$1,100,000
150										
151	Total Utility Plant	$7,250,000	$7,250,000	$7,250,000	$7,250,000	$7,250,000	$7,250,000	$7,250,000	$7,250,000	$7,250,000
152	Less Accumulated Depreciation	$1,455,000	$1,697,500	$1,940,000	$2,182,500	$2,425,000	$2,667,500	$2,910,000	$3,152,500	$3,395,000
153	Total Net Utility Plant	$5,795,000	$5,552,500	$5,310,000	$5,067,500	$4,825,000	$4,582,500	$4,340,000	$4,097,500	$3,855,000
154	Current Assets & Other	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets	$5,895,000	$5,652,500	$5,410,000	$5,167,500	$4,925,000	$4,682,500	$4,440,000	$4,197,500	$3,955,000
156										
157	Total Equity	$5,845,000	$5,602,500	$5,360,000	$5,117,500	$4,875,000	$4,632,500	$4,390,000	$4,147,500	$3,905,000
158	Long-Term Liabilities	$0	$0	$0	$0	$0	$0	$0	$0	$0
159	Current Liabilities	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
161	Total Liabilities & Equity	$5,895,000	$5,652,500	$5,410,000	$5,167,500	$4,925,000	$4,682,500	$4,440,000	$4,197,500	$3,955,000

Summary 2

Strategy 3

Retain Utility

1.5 MW of Wind Generation

with No Financial Gift

	A	B	C	D	E	F	G	H	I	J
1	**Strategy 3: 1.5 MW Wind, No**	**Summary of Power Supply and Financial Modeling for Greensburg**								
2	**Gift, 100% Green Power**	**Preliminary and Confidential**								
3			**YEAR >>**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
4	**Load, Peak, Energy Prices**									
5	Peak Load			0	4,489	0	2,479	3,360	3,444	3,478
6	Storage System Losses, MWH			0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH			15,622	15,474	7,414	9,496	12,867	13,189	13,321
8										
9	Natural Gas Cost $ / MMBTU					$7.00	$7.50	$7.80	$8.11	$8.44
10	Biodiesel Cost, $ / Gal					$2.50	$2.60	$2.70	$2.81	$2.92
11	Diesel Cost, $ / Gal					$2.75	$2.86	$2.97	$3.09	$3.22
12										
13	**Wind Generation**									
14	Wind Generation, Number of Turbines							1	1	1
15	Wind Generation, MW	1.50	Turbine Size, in MW		0.0%	Capital Contribution, Gift =		1.50	1.50	1.50
16	Wind Generation, MWH	41.0%	Annual Capacity Factor Used			-0.30%	Array Delta	5,387	5,387	5,387
17	Wind Generation Capital Cost, $	1	2	3	4	< # of WTs		$3,300,000	$0	$0
18	Wind Generation O&M	$2,200	$2,100	$2,025	$1,975	< Total Cost per kW		$39,000	$40,170	$41,375
19	Wind Generation R&R & Warranty	$12	$ / kW in 2009		$26	$ / kW in 2009		$18,000	$18,540	$19,096
20										
21	Wind Generation as a % of Total Load							41.9%	40.8%	40.4%
22	Excess Wind Gen to Grid, %							5.3%	5.3%	5.3%
23	Excess Wind Gen to Grid, MWh							284	284	284
24										
25	**Energy Storage System**									
26	Energy Storage, MW			0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $			$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $			$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed			0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered			0	0	0	0	0	0	0
32	Energy Storage MWH Lost			0	0	0	0	0	0	0
33										
34	**Purchases & Sales**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
35	Purchases from Grid			14,823	15,296	7,364	8,846	12,217	12,539	12,671
36	Wind Power Sold to Grid						0	5,387	5,387	5,387
37	Equivalent Net Purchases (Sales to Grid)			14,823	15,296	7,364	8,846	6,830	7,152	7,284
38							0.0%	53.1%	54.2%	54.7%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH						$45.0	$46.4	$47.7	$49.2
41	Climate Change Costs, $/MWH	Based on TAW 3 Scenario					$0.00	$0.00	$4.89	$6.36
42										
43	Integration Costs	260,000	MWh Pool Base				$0.0	$0.2	$0.2	$0.2
44	Purchased Energy, Dollars			$800,462	$769,694	$371,610	$398,086	$568,316	$662,061	$705,769
45	Cost of Renewable Energy Credits						$8,547	$12,387	$19,449	$25,874
46	Purchased Demand, in kW						2,479	3,360	3,444	3,478
47	Demand Charge Rate, $ / kW-Month						$0.00	$0.00	$0.00	$0.00
48	Demand Charges						$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	J
49	Total Cost of Purchased Power & REC's, Dollars			$857,584	$701,754	$371,610	$406,633	$580,703	$681,510	$731,642
50	Transmission Service						$60,000	$83,332	$87,551	$90,638
51				$57.85	$45.88	$50.46	$45.97	$47.53	$54.35	$57.74
52	Total Cost of Purchased Power, $ / Mwh									
53	Rate for Sale of Excess Wind Power	$45.00	per Mwh	0.0%	Escalator		$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power						$0	$242,433	$242,433	$242,433
55	Revenue from Sale of RECs	$0.00	per Mwh	0.0%	Escalator		$0	$0	$0	$0
56										
57	**Engine Plant**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
58	Existing Engine Generating Capacity			6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity			0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW			$0	$0	$0	$750	$773	$796	$820
61	New Engine Total Capital Cost, $			$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**			2005	2006	2007	1/2 Year	2009	2010	2011
65	Energy Generated by Engines, MWh			799	178	50	650	650	650	650
66	Percentage from Natural Gas			0.0%	0.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel			0%	0%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel			0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $			$ 69,539	$ 104,645	$ 10,395	$ 49,500	$ 51,480	$ 53,539	$ 55,681
71	Diesel Cost, $ as pilot fuel for gas			$ 14,093	$ -	$ 3,312	$ 17,223	$ 17,912	$ 18,628	$ 19,373
72	Biodiesel Cost, $ as pilot or replacement for gas			$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $			$ 83,632	$ 104,645	$ 13,707	$ 66,723	$ 69,392	$ 72,167	$ 75,054
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services			$ 206,081	$ 193,952	$ 120,010	$ 123,610	$ 127,319	$ 131,138	$ 135,072
77	Existing Plant Contractual Services			$ 171,345	$ 102,954	$ 54,860	$ 141,264	$ 145,502	$ 149,867	$ 154,363
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services			$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services			0	0	0	0	0	0	0
82										
83	**Cash receipts**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
84	Sales			$1,609,787	$1,791,549	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
85	Rentals			$0	$0	$0	$0	$0	$0	$0
86	Security Lights			$3,458	$4,218	$1,963	$2,514	$3,407	$3,492	$3,703
87	Service Charge			$1,328	$1,668	$776	$994	$1,347	$1,381	$1,464
88	Materials sold			$0	$3,335	$1,718	$1,769	$1,822	$1,877	$1,933
89	Other			$185	$96	$145	$149	$154	$158	$163
90	Wind Power & REC Sales			$0	$0	$0	$0	$242,433	$242,433	$242,433
91	Total cash receipts			$1,614,758	$1,800,866	$838,283	$1,073,242	$1,696,040	$1,732,405	$1,822,487
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services			$206,081	$193,952	$120,010	$123,610	$127,319	$131,138	$135,072
95	Engine Plant Contractual Services			$171,345	$102,954	$54,860	$141,264	$145,502	$149,867	$154,363
96										
97	Wind Generator O&M, R&R						$0	$57,000	$58,710	$60,471
98	Commodities			$14,969	$17,726	$16,838	$17,343	$17,863	$18,399	$18,951

	A	B	C	D	E	F	G	H	I	J
99	Diesel fuel & oil			$14,093	$0	$4,741	$8,533	$17,066	$17,578	$18,105
100	Electricity, RECs, & Transmission Service			$857,584	$701,754	$371,610	$466,633	$664,034	$769,062	$822,280
101	Natural Gas			$69,539	$104,645	$10,395	$49,500	$51,480	$53,539	$55,681
102	Capital outlay			$89	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services			$158,841	$155,983	$162,134	$166,998	$172,008	$177,169	$182,484
105	Contractual Services			$13,493	$8,817	$11,490	$11,834	$12,189	$12,555	$12,932
106	Commodities			$41,809	$47,408	$45,947	$47,325	$48,745	$50,207	$51,713
107	Capital outlay			$0	$3,984	$2,052	$2,113	$2,177	$2,242	$2,309
108	**General & Administrative**									
109	Contractual Services			$2,644	$2,835	$2,822	$2,906	$2,994	$3,083	$3,176
110	Commodities			$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**			$175,758	$175,758	$0	$0	$220,000	$220,000	$220,000
112	**Reimbursed expenditures**			($9,928)	($4,315)	($7,335)	($7,555)	($7,782)	($8,015)	($8,256)
113	**Total Expenditures**			$1,716,317	$1,511,501	$795,562	$1,030,505	$1,530,595	$1,655,534	$1,729,282
114										
115	Receipts over (under) expenditures			($101,559)	$289,365	$42,721	$42,737	$165,445	$76,872	$93,205
116	Unencumbered cash (deficit) BOY			$9,040	($92,519)	$196,846	$189,546	$189,546	$268,179	$268,179
117	Trasfer to City			$0	$0	($50,021)	($42,737)	($86,813)	($76,872)	($93,205)
118	Unencumbered cash (deficit), EOY			($92,519)	$196,846	$189,546	$189,546	$268,179	$268,179	$268,179
119										
120	**Retail Sales by Class**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
121										
122	Residential Mwh			10,338	9,533	4,773	6,113	8,284	8,491	8,576
123	Commercial Mwh			4,303	4,288	2,122	2,718	3,683	3,775	3,813
124	Furnished without charges & Losses			981	1,653	519	665	901	923	932
125	Total Mwh to System			15,622	15,474	7,414	9,496	12,867	13,189	13,321
126	Losses as a % of Sales			6.7%	12.0%	10.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.0%
129	Residential Cost per kWh			$0.1115	$0.1216	$0.1216	$0.1216	$0.1216	$0.1216	$0.1277
130	Commercial Cost per kWh			$0.1106	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1254
131	Residential Revenue			$1,153,000	$1,159,000	$580,292	$743,262	$1,007,112	$1,032,300	$1,094,754
132	Commercial Revenue			$476,000	$512,000	$253,391	$324,553	$439,766	$450,765	$478,036
133	Total Sales Revenue			$1,629,000	$1,671,000	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
134	Average Retail Sales Revenue ¢ per kWh			11.13	12.09	12.09	12.09	12.09	12.09	12.70
135	Residential Customers			792	783					
136	Commercial Customers			132	148					
137										
138	**Simplified Balance Sheet**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
139	Distribution System - New Investment					$4,500,000	$0	$0	$0	$0
140	Cumulative Investment	Existing Distribution that Survived>			$250,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation					$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation					$142,500	$285,000	$427,500	$570,000	$712,500
143	Net Depreciated Investment					$4,607,500	$4,465,000	$4,322,500	$4,180,000	$4,037,500
144										
145	Production Plant - New Investment					$0	$0	$3,300,000	$0	$0
146	Cumulative Investment		Existing Diesel Plant >		$2,500,000	$2,500,000	$2,500,000	$5,800,000	$5,800,000	$5,800,000
147	Annual Depreciation					$100,000	$100,000	$232,000	$232,000	$232,000
148	Accumulated Depreciation					$100,000	$200,000	$432,000	$664,000	$896,000

	A	B	C	D	E	F	G	H	I	J
149	Net Depreciated Investment					$2,400,000	$2,300,000	$5,368,000	$5,136,000	$4,904,000
150										
151	Total Utility Plant					$7,250,000	$7,250,000	$10,550,000	$10,550,000	$10,550,000
152	Less Accumulated Depreciation					$242,500	$485,000	$859,500	$1,234,000	$1,608,500
153	Total Net Utility Plant					$7,007,500	$6,765,000	$9,690,500	$9,316,000	$8,941,500
154	Current Assets & Other					$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets					$7,107,500	$6,865,000	$9,790,500	$9,416,000	$9,041,500
156										
157	Total Equity					$7,057,500	$6,815,000	$6,660,500	$6,506,000	$6,351,500
158	Long-Term Liabilities					$0	$0	$3,080,000	$2,860,000	$2,640,000
159	Current Liabilities					$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities					$50,000	$50,000	$3,130,000	$2,910,000	$2,690,000
161	Total Liabilities & Equity					$7,107,500	$6,865,000	$9,790,500	$9,416,000	$9,041,500

	K	L	M	N	O	P	Q	R	S	T
1	**Strategy 3: 1.5 MW Wind, No Gift, 100% Green Power**	**Summary of Power Supply and Financial Modeling for Greensburg**								
2		**Preliminary and Confidential**								
3		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
4	**Load, Peak, Energy Prices**									
5	Peak Load	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
6	Storage System Losses, MWH	0	0	0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
8										
9	Natural Gas Cost $ / MMBTU	$8.77	$9.12	$9.49	$9.87	$10.26	$10.67	$11.10	$11.55	$12.01
10	Biodiesel Cost, $ / Gal	$3.04	$3.16	$3.29	$3.42	$3.56	$3.70	$3.85	$4.00	$4.16
11	Diesel Cost, $ / Gal	$3.35	$3.48	$3.62	$3.76	$3.91	$4.07	$4.23	$4.40	$4.58
12										
13	**Wind Generation**									
14	Wind Generation, Number of Turbines	1	1	1	1	1	1	1	1	1
15	Wind Generation, MW	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
16	Wind Generation, MWH	5,387	5,387	5,387	5,368	5,368	5,368	5,368	5,368	5,368
17	Wind Generation Capital Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind Generation O&M	$42,616	$43,895	$45,212	$46,568	$47,965	$49,404	$50,886	$52,413	$53,985
19	Wind Generation R&R & Warranty	$19,669	$20,259	$20,867	$21,493	$22,138	$22,802	$23,486	$24,190	$24,916
20										
21	Wind Generation as a % of Total Load	40.0%	39.6%	39.3%	38.7%	38.3%	38.0%	37.6%	37.2%	36.8%
22	Excess Wind Gen to Grid, %	5.3%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
23	Excess Wind Gen to Grid, MWh	284	150	150	149	149	149	149	149	149
24										
25	**Energy Storage System**									
26	Energy Storage, MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed	0	0	0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered	0	0	0	0	0	0	0	0	0
32	Energy Storage MWH Lost	0	0	0	0	0	0	0	0	0
33										
34	**Purchases & Sales**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
35	Purchases from Grid	12,804	12,939	13,075	13,212	13,351	13,491	13,632	13,775	13,919
36	Wind Power Sold to Grid	5,387	5,387	5,387	5,368	5,368	5,368	5,368	5,368	5,368
37	Equivalent Net Purchases (Sales to Grid)	7,417	7,552	7,687	7,844	7,983	8,123	8,264	8,407	8,551
38		55.1%	55.6%	56.0%	56.6%	57.0%	57.4%	57.9%	58.3%	58.7%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH	$50.6	$52.2	$53.7	$55.3	$57.0	$58.7	$60.5	$62.3	$64.2
41	Climate Change Costs, $/MWH	$7.83	$9.29	$10.76	$12.23	$13.70	$15.16	$16.63	$18.10	$19.57
42										
43	Integration Costs	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
44	Purchased Energy, Dollars	$750,868	$797,406	$845,431	$894,980	$946,129	$998,920	$1,053,408	$1,109,652	$1,167,710
45		$32,262	$38,610	$44,912	$51,320	$57,536	$63,691	$69,780	$75,798	$81,739
46	Purchased Demand, in kW	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
47	Demand Charge Rate, $ / kW-Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
48	Demand Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0

	K	L	M	N	O	P	Q	R	S	T
49	Total Cost of Purchased Power & REC's, Dollars	$783,130	$836,016	$890,342	$946,300	$1,003,665	$1,062,611	$1,123,188	$1,185,449	$1,249,449
50	Transmission Service	$93,833	$97,140	$100,564	$104,109	$107,779	$111,578	$115,511	$119,583	$123,799
51	Total Cost of Purchased Power, $ / Mwh	$61.16	$64.61	$68.10	$71.62	$75.18	$78.77	$82.39	$86.06	$89.76
52										
53	Rate for Sale of Excess Wind Power	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power	$242,433	$242,433	$242,433	$241,546	$241,546	$241,546	$241,546	$241,546	$241,546
55	Revenue from Sale of RECs	$0	$0	$0	$0	$0	$0	$0	$0	$0
56										
57	**Engine Plant**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
58	Existing Engine Generating Capacity	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW	$844	$869	$896	$922	$950	$979	$1,008	$1,038	$1,069
61	New Engine Total Capital Cost, $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**	2012	2013	2014	2015	2016	2017	2018	2019	2020
65	Energy Generated by Engines, MWh	650	650	650	650	650	650	650	650	650
66	Percentage from Natural Gas	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel	10%	10%	10%	10%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel	0%	0%	0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $	$ 57,908	$ 60,224	$ 62,633	$ 65,139	$ 67,744	$ 70,454	$ 73,272	$ 76,203	$ 79,251
71	Diesel Cost, $ as pilot fuel for gas	$ 20,148	$ 20,954	$ 21,792	$ 22,664	$ 23,570	$ 24,513	$ 25,494	$ 26,513	$ 27,574
72	Biodiesel Cost, $ as pilot or replacement for gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $	$ 78,056	$ 81,178	$ 84,425	$ 87,802	$ 91,315	$ 94,967	$ 98,766	$ 102,716	$ 106,825
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services	$ 139,124	$ 143,298	$ 147,597	$ 152,025	$ 156,586	$ 161,283	$ 166,122	$ 171,105	$ 176,239
77	Existing Plant Contractual Services	$ 158,994	$ 163,764	$ 168,677	$ 173,737	$ 178,949	$ 184,317	$ 189,847	$ 195,542	$ 201,409
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services	$0	$0	$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services	0	0	0	0	0	0	0	0	0
82										
83	**Cash receipts**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
84	Sales	$1,588,518	$1,732,756	$1,750,083	$1,908,991	$1,928,081	$2,103,151	$2,124,182	$2,145,424	$2,166,878
85	Rentals	$0	$0	$0	$0	$0	$0	$0	$0	$0
86	Security Lights	$3,740	$4,080	$4,120	$4,495	$4,539	$4,952	$5,001	$5,051	$5,102
87	Service Charge	$1,479	$1,613	$1,629	$1,777	$1,795	$1,958	$1,978	$1,997	$2,017
88	Materials sold	$1,991	$2,051	$2,112	$2,176	$2,241	$2,308	$2,377	$2,449	$2,522
89	Other	$168	$173	$178	$183	$189	$194	$200	$206	$213
90	Wind Power & REC Sales	$242,433	$242,433	$242,433	$241,546	$241,546	$241,546	$241,546	$241,546	$241,546
91	Total cash receipts	$1,838,329	$1,983,105	$2,000,557	$2,159,168	$2,178,391	$2,354,109	$2,375,285	$2,396,674	$2,418,278
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services	$139,124	$143,298	$147,597	$152,025	$156,586	$161,283	$166,122	$171,105	$176,239
95	Engine Plant Contractual Services	$158,994	$163,764	$168,677	$173,737	$178,949	$184,317	$189,847	$195,542	$201,409
96										
97	Wind Generator O&M, R&R	$62,285	$64,154	$66,079	$68,061	$70,103	$72,206	$74,372	$76,603	$78,901
98	Commodities	$19,520	$20,105	$20,709	$21,330	$21,970	$22,629	$23,308	$24,007	$24,727

	K	L	M	N	O	P	Q	R	S	T
99	Diesel fuel & oil	$18,648	$19,208	$19,784	$20,377	$20,989	$21,618	$22,267	$22,935	$23,623
100	Electricity, RECs, & Transmission Service	$876,963	$933,156	$990,907	$1,050,410	$1,111,444	$1,174,189	$1,238,700	$1,305,033	$1,373,247
101	Natural Gas	$57,908	$60,224	$62,633	$65,139	$67,744	$70,454	$73,272	$76,203	$79,251
102	Capital outlay	$0	$0	$0	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services	$187,958	$193,597	$199,405	$205,387	$211,549	$217,895	$224,432	$231,165	$238,100
105	Contractual Services	$13,320	$13,719	$14,131	$14,555	$14,991	$15,441	$15,904	$16,381	$16,873
106	Commodities	$53,265	$54,863	$56,509	$58,204	$59,950	$61,749	$63,601	$65,509	$67,474
107	Capital outlay	$2,379	$2,450	$2,523	$2,599	$2,677	$2,757	$2,840	$2,925	$3,013
108	**General & Administrative**									
109	Contractual Services	$3,271	$3,369	$3,470	$3,574	$3,682	$3,792	$3,906	$4,023	$4,144
110	Commodities	$0	$0	$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**	$220,000	$220,000	$220,000	$220,000	$220,000	$220,000	$220,000	$220,000	$220,000
112	**Reimbursed expenditures**	($8,503)	($8,759)	($9,021)	($9,292)	($9,571)	($9,858)	($10,154)	($10,458)	($10,772)
113	**Total Expenditures**	$1,805,131	$1,883,149	$1,963,401	$2,046,106	$2,131,062	$2,218,473	$2,308,417	$2,400,974	$2,496,229
114										
115	Receipts over (under) expenditures	$33,198	$99,957	$37,155	$113,062	$47,329	$135,636	$66,868	($4,300)	($77,951)
116	Unencumbered cash (deficit) BOY	$268,179	$268,179	$268,179	$268,179	$268,179	$268,179	$277,625	$277,625	$273,325
117	Trasfer to City	($33,198)	($99,957)	($37,155)	($113,062)	($47,329)	($126,189)	($66,868)	$0	$0
118	Unencumbered cash (deficit), EOY	$268,179	$268,179	$268,179	$268,179	$268,179	$277,625	$277,625	$273,325	$195,374
119										
120	**Retail Sales by Class**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
121										
122	Residential Mwh	8,662	8,748	8,836	8,924	9,013	9,103	9,194	9,286	9,379
123	Commercial Mwh	3,851	3,890	3,928	3,968	4,007	4,047	4,088	4,129	4,170
124	Furnished without charges & Losses	942	951	961	970	980	990	1,000	1,010	1,020
125	Total Mwh to System	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
126	Losses as a % of Sales	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year	0.0%	8.0%	0.0%	8.0%	0.0%	8.0%	0.0%	0.0%	0.0%
129	Residential Cost per kWh	$0.1277	$0.1379	$0.1379	$0.1489	$0.1489	$0.1608	$0.1608	$0.1608	$0.1608
130	Commercial Cost per kWh	$0.1254	$0.1354	$0.1354	$0.1462	$0.1462	$0.1579	$0.1579	$0.1579	$0.1579
131	Residential Revenue	$1,105,702	$1,206,100	$1,218,161	$1,328,769	$1,342,057	$1,463,916	$1,478,555	$1,493,341	$1,508,274
132	Commercial Revenue	$482,817	$526,656	$531,923	$580,222	$586,024	$639,235	$645,627	$652,083	$658,604
133	Total Sales Revenue	$1,588,518	$1,732,756	$1,750,083	$1,908,991	$1,928,081	$2,103,151	$2,124,182	$2,145,424	$2,166,878
134	Average Retail Sales Revenue ¢ per kWh	12.70	13.71	13.71	14.81	14.81	15.99	15.99	15.99	15.99
135	Residential Customers									
136	Commercial Customers									
137										
138	**Simplified Balance Sheet**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
139	Distribution System - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
140	Cumulative Investment	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation	$855,000	$997,500	$1,140,000	$1,282,500	$1,425,000	$1,567,500	$1,710,000	$1,852,500	$1,995,000
143	Net Depreciated Investment	$3,895,000	$3,752,500	$3,610,000	$3,467,500	$3,325,000	$3,182,500	$3,040,000	$2,897,500	$2,755,000
144										
145	Production Plant - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
146	Cumulative Investment	$5,800,000	$5,800,000	$5,800,000	$5,800,000	$5,800,000	$5,800,000	$5,800,000	$5,800,000	$5,800,000
147	Annual Depreciation	$232,000	$232,000	$232,000	$232,000	$232,000	$232,000	$232,000	$232,000	$232,000
148	Accumulated Depreciation	$1,128,000	$1,360,000	$1,592,000	$1,824,000	$2,056,000	$2,288,000	$2,520,000	$2,752,000	$2,984,000

	K	L	M	N	O	P	Q	R	S	T
149	Net Depreciated Investment	$4,672,000	$4,440,000	$4,208,000	$3,976,000	$3,744,000	$3,512,000	$3,280,000	$3,048,000	$2,816,000
150										
151	Total Utility Plant	$10,550,000	$10,550,000	$10,550,000	$10,550,000	$10,550,000	$10,550,000	$10,550,000	$10,550,000	$10,550,000
152	Less Accumulated Depreciation	$1,983,000	$2,357,500	$2,732,000	$3,106,500	$3,481,000	$3,855,500	$4,230,000	$4,604,500	$4,979,000
153	Total Net Utility Plant	$8,567,000	$8,192,500	$7,818,000	$7,443,500	$7,069,000	$6,694,500	$6,320,000	$5,945,500	$5,571,000
154	Current Assets & Other	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets	$8,667,000	$8,292,500	$7,918,000	$7,543,500	$7,169,000	$6,794,500	$6,420,000	$6,045,500	$5,671,000
156										
157	Total Equity	$6,197,000	$6,042,500	$5,888,000	$5,733,500	$5,579,000	$5,424,500	$5,270,000	$5,115,500	$4,961,000
158	Long-Term Liabilities	$2,420,000	$2,200,000	$1,980,000	$1,760,000	$1,540,000	$1,320,000	$1,100,000	$880,000	$660,000
159	Current Liabilities	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities	$2,470,000	$2,250,000	$2,030,000	$1,810,000	$1,590,000	$1,370,000	$1,150,000	$930,000	$710,000
161	Total Liabilities & Equity	$8,667,000	$8,292,500	$7,918,000	$7,543,500	$7,169,000	$6,794,500	$6,420,000	$6,045,500	$5,671,000

Summary 3

Strategy 3

Retain Utility

3.0 MW of Wind Generation

with No Financial Gift

	A	B	C	D	E	F	G	H	I	J
1	**Strategy 3: 3 MW Wind, No**	**Summary of Power Supply and Financial Modeling for Greensburg**								
2	**Gift, 100% Green Power**	**Preliminary and Confidential**								
3			**YEAR >>**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
4	**Load, Peak, Energy Prices**									
5	Peak Load			0	4,489	0	2,479	3,360	3,444	3,478
6	Storage System Losses, MWH			0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH			15,622	15,474	7,414	9,496	12,867	13,189	13,321
8										
9	Natural Gas Cost $ / MMBTU					$7.00	$7.50	$7.80	$8.11	$8.44
10	Biodiesel Cost, $ / Gal					$2.50	$2.60	$2.70	$2.81	$2.92
11	Diesel Cost, $ / Gal					$2.75	$2.86	$2.97	$3.09	$3.22
12										
13	**Wind Generation**									
14	Wind Generation, Number of Turbines							2	2	2
15	Wind Generation, MW	1.50	Turbine Size, in MW		0.0%	Capital Contribution,	Gift =	3.00	3.00	3.00
16	Wind Generation, MWH	41.0%	Annual Capacity Factor Used			-0.30%	Array Delta	10,696	10,696	10,696
17	Wind Generation Capital Cost, $	1	2	3	4	< # of WTs		$6,300,000	$0	$0
18	Wind Generation O&M	$2,200	$2,100	$2,025	$1,975	< Total Cost per kW		$74,100	$76,323	$78,613
19	Wind Generation R&R & Warranty	$12	$ / kW in 2009		$26	$ / kW in 2009		$34,200	$35,226	$36,283
20										
21	Wind Generation as a % of Total Load							83.1%	81.1%	80.3%
22	Excess Wind Gen to Grid, %							30.0%	30.0%	30.0%
23	Excess Wind Gen to Grid, MWh							3,205	3,205	3,205
24										
25	**Energy Storage System**									
26	Energy Storage, MW			0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $			$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $			$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed			0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered			0	0	0	0	0	0	0
32	Energy Storage MWH Lost			0	0	0	0	0	0	0
33										
34	**Purchases & Sales**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
35	Purchases from Grid			14,823	15,296	7,364	8,846	12,217	12,539	12,671
36	Wind Power Sold to Grid						0	10,696	10,696	10,696
37	Equivalent Net Purchases (Sales to Grid)			14,823	15,296	7,364	8,846	1,521	1,843	1,975
38							0.0%	11.8%	14.0%	14.8%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH						$45.0	$46.4	$47.7	$49.2
41	Climate Change Costs, $/MWH	Based on TAW 3 Scenario					$0.00	$0.00	$4.89	$6.36
42										
43	Integration Costs	260,000	MWh Pool Base				$0.0	$0.5	$0.5	$0.5
44	Purchased Energy, Dollars			$800,462	$769,694	$371,610	$398,086	$571,978	$665,820	$709,566
45	Cost of Renewable Energy Credits						$8,547	$1,769	$3,523	$4,640
46	Purchased Demand, in kW						2,479	3,360	3,444	3,478
47	Demand Charge Rate, $ / kW-Month						$0.00	$0.00	$0.00	$0.00
48	Demand Charges						$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	J
49	Total Cost of Purchased Power & REC's, Dollars			$857,584	$701,754	$371,610	$406,633	$573,747	$669,343	$714,206
50	Transmission Service						$60,000	$83,332	$87,551	$90,638
51	Total Cost of Purchased Power, $ / Mwh			$57.85	$45.88	$50.46	$45.97	$46.96	$53.38	$56.36
52										
53	Rate for Sale of Excess Wind Power	$45.00	per Mwh	0.0%	Escalator		$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power						$0	$481,318	$481,318	$481,318
55	Revenue from Sale of RECs	$0.00	per Mwh	0.0%	Escalator		$0	$0	$0	$0
56										
57	**Engine Plant**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
58	Existing Engine Generating Capacity			6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity			0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW			$0	$0	$0	$750	$773	$796	$820
61	New Engine Total Capital Cost, $			$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**			2005	2006	2007	1/2 Year	2009	2010	2011
65	Energy Generated by Engines, MWh			799	178	50	650	650	650	650
66	Percentage from Natural Gas			0.0%	0.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel			0%	0%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel			0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $			$ 69,539	$ 104,645	$ 10,395	$ 49,500	$ 51,480	$ 53,539	$ 55,681
71	Diesel Cost, $ as pilot fuel for gas			$ 14,093	$ -	$ 3,312	$ 17,223	$ 17,912	$ 18,628	$ 19,373
72	Biodiesel Cost, $ as pilot or replacement for gas			$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $			$ 83,632	$ 104,645	$ 13,707	$ 66,723	$ 69,392	$ 72,167	$ 75,054
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services			$ 206,081	$ 193,952	$ 120,010	$ 123,610	$ 127,319	$ 131,138	$ 135,072
77	Existing Plant Contractual Services			$ 171,345	$ 102,954	$ 54,860	$ 141,264	$ 145,502	$ 149,867	$ 154,363
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services			$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services			0	0	0	0	0	0	0
82										
83	**Cash receipts**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
84	Sales			$1,609,787	$1,791,549	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
85	Rentals			$0	$0	$0	$0	$0	$0	$0
86	Security Lights			$3,458	$4,218	$1,963	$2,514	$3,407	$3,492	$3,703
87	Service Charge			$1,328	$1,668	$776	$994	$1,347	$1,381	$1,464
88	Materials sold			$0	$3,335	$1,718	$1,769	$1,822	$1,877	$1,933
89	Other			$185	$96	$145	$149	$154	$158	$163
90	Wind Power & REC Sales			$0	$0	$0	$0	$481,318	$481,318	$481,318
91	Total cash receipts			$1,614,758	$1,800,866	$838,283	$1,073,242	$1,934,925	$1,971,291	$2,061,372
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services			$206,081	$193,952	$120,010	$123,610	$127,319	$131,138	$135,072
95	Engine Plant Contractual Services			$171,345	$102,954	$54,860	$141,264	$145,502	$149,867	$154,363
96										
97	Wind Generator O&M, R&R						$0	$108,300	$111,549	$114,895
98	Commodities			$14,969	$17,726	$16,838	$17,343	$17,863	$18,399	$18,951

	A	B	C	D	E	F	G	H	I	J
99	Diesel fuel & oil			$14,093	$0	$4,741	$8,533	$17,066	$17,578	$18,105
100	Electricity, RECs, & Transmission Service			$857,584	$701,754	$371,610	$466,633	$657,079	$756,894	$804,843
101	Natural Gas			$69,539	$104,645	$10,395	$49,500	$51,480	$53,539	$55,681
102	Capital outlay			$89	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services			$158,841	$155,983	$162,134	$166,998	$172,008	$177,169	$182,484
105	Contractual Services			$13,493	$8,817	$11,490	$11,834	$12,189	$12,555	$12,932
106	Commodities			$41,809	$47,408	$45,947	$47,325	$48,745	$50,207	$51,713
107	Capital outlay			$0	$3,984	$2,052	$2,113	$2,177	$2,242	$2,309
108	**General & Administrative**									
109	Contractual Services			$2,644	$2,835	$2,822	$2,906	$2,994	$3,083	$3,176
110	Commodities			$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**			$175,758	$175,758	$0	$0	$420,000	$420,000	$420,000
112	**Reimbursed expenditures**			($9,928)	($4,315)	($7,335)	($7,555)	($7,782)	($8,015)	($8,256)
113	**Total Expenditures**			$1,716,317	$1,511,501	$795,562	$1,030,505	$1,774,940	$1,896,205	$1,966,269
114										
115	Receipts over (under) expenditures			($101,559)	$289,365	$42,721	$42,737	$159,986	$75,085	$95,103
116	Unencumbered cash (deficit) BOY			$9,040	($92,519)	$196,846	$189,546	$189,546	$262,719	$262,719
117	Trasfer to City			$0	$0	($50,021)	($42,737)	($86,813)	($75,085)	($94,367)
118	Unencumbered cash (deficit), EOY			($92,519)	$196,846	$189,546	$189,546	$262,719	$262,719	$263,455
119										
120	**Retail Sales by Class**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
121										
122	Residential Mwh			10,338	9,533	4,773	6,113	8,284	8,491	8,576
123	Commercial Mwh			4,303	4,288	2,122	2,718	3,683	3,775	3,813
124	Furnished without charges & Losses			981	1,653	519	665	901	923	932
125	Total Mwh to System			15,622	15,474	7,414	9,496	12,867	13,189	13,321
126	Losses as a % of Sales			6.7%	12.0%	10.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.0%
129	Residential Cost per kWh			$0.1115	$0.1216	$0.1216	$0.1216	$0.1216	$0.1216	$0.1277
130	Commercial Cost per kWh			$0.1106	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1254
131	Residential Revenue			$1,153,000	$1,159,000	$580,292	$743,262	$1,007,112	$1,032,300	$1,094,754
132	Commercial Revenue			$476,000	$512,000	$253,391	$324,553	$439,766	$450,765	$478,036
133	Total Sales Revenue			$1,629,000	$1,671,000	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
134	Average Retail Sales Revenue ¢ per kWh			11.13	12.09	12.09	12.09	12.09	12.09	12.70
135	Residential Customers			792	783					
136	Commercial Customers			132	148					
137										
138	**Simplified Balance Sheet**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
139	Distribution System - New Investment					$4,500,000	$0	$0	$0	$0
140	Cumulative Investment	Existing Distribution that Survived>			$250,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation					$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation					$142,500	$285,000	$427,500	$570,000	$712,500
143	Net Depreciated Investment					$4,607,500	$4,465,000	$4,322,500	$4,180,000	$4,037,500
144										
145	Production Plant - New Investment					$0	$0	$6,300,000	$0	$0
146	Cumulative Investment		Existing Diesel Plant >		$2,500,000	$2,500,000	$2,500,000	$8,800,000	$8,800,000	$8,800,000
147	Annual Depreciation					$100,000	$100,000	$352,000	$352,000	$352,000
148	Accumulated Depreciation					$100,000	$200,000	$552,000	$904,000	$1,256,000

	A	B	C	D	E	F	G	H	I	J
149	Net Depreciated Investment					$2,400,000	$2,300,000	$8,248,000	$7,896,000	$7,544,000
150										
151	Total Utility Plant					$7,250,000	$7,250,000	$13,550,000	$13,550,000	$13,550,000
152	Less Accumulated Depreciation					$242,500	$485,000	$979,500	$1,474,000	$1,968,500
153	Total Net Utility Plant					$7,007,500	$6,765,000	$12,570,500	$12,076,000	$11,581,500
154	Current Assets & Other					$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets					$7,107,500	$6,865,000	$12,670,500	$12,176,000	$11,681,500
156										
157	Total Equity					$7,057,500	$6,815,000	$6,740,500	$6,666,000	$6,591,500
158	Long-Term Liabilities					$0	$0	$5,880,000	$5,460,000	$5,040,000
159	Current Liabilities					$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities					$50,000	$50,000	$5,930,000	$5,510,000	$5,090,000
161	Total Liabilities & Equity					$7,107,500	$6,865,000	$12,670,500	$12,176,000	$11,681,500

	K	L	M	N	O	P	Q	R	S	T
1	**Strategy 3: 3 MW Wind, No Gift, 100% Green Power**	**Summary of Power Supply and Financial Modeling for Greensburg**								
2		**Preliminary and Confidential**								
3		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
4	**Load, Peak, Energy Prices**									
5	Peak Load	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
6	Storage System Losses, MWH	0	0	0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
8										
9	Natural Gas Cost $ / MMBTU	$8.77	$9.12	$9.49	$9.87	$10.26	$10.67	$11.10	$11.55	$12.01
10	Biodiesel Cost, $ / Gal	$3.04	$3.16	$3.29	$3.42	$3.56	$3.70	$3.85	$4.00	$4.16
11	Diesel Cost, $ / Gal	$3.35	$3.48	$3.62	$3.76	$3.91	$4.07	$4.23	$4.40	$4.58
12										
13	**Wind Generation**									
14	Wind Generation, Number of Turbines	2	2	2	2	2	2	2	2	2
15	Wind Generation, MW	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
16	Wind Generation, MWH	10,696	10,696	10,696	10,617	10,617	10,617	10,617	10,617	10,617
17	Wind Generation Capital Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind Generation O&M	$80,971	$83,400	$85,902	$88,479	$91,134	$93,868	$96,684	$99,584	$102,572
19	Wind Generation R&R & Warranty	$37,371	$38,492	$39,647	$40,837	$42,062	$43,324	$44,623	$45,962	$47,341
20										
21	Wind Generation as a % of Total Load	79.5%	78.7%	77.9%	76.6%	75.8%	75.1%	74.3%	73.6%	72.9%
22	Excess Wind Gen to Grid, %	27.3%	27.3%	27.3%	27.3%	27.3%	27.3%	24.6%	24.6%	24.6%
23	Excess Wind Gen to Grid, MWh	2,924	2,924	2,924	2,903	2,903	2,903	2,607	2,607	2,607
24										
25	**Energy Storage System**									
26	Energy Storage, MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed	0	0	0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered	0	0	0	0	0	0	0	0	0
32	Energy Storage MWH Lost	0	0	0	0	0	0	0	0	0
33										
34	**Purchases & Sales**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
35	Purchases from Grid	12,804	12,939	13,075	13,212	13,351	13,491	13,632	13,775	13,919
36	Wind Power Sold to Grid	10,696	10,696	10,696	10,617	10,617	10,617	10,617	10,617	10,617
37	Equivalent Net Purchases (Sales to Grid)	2,108	2,243	2,379	2,595	2,734	2,874	3,015	3,158	3,302
38		15.7%	16.5%	17.3%	18.7%	19.5%	20.3%	21.1%	21.9%	22.7%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH	$50.6	$52.2	$53.7	$55.3	$57.0	$58.7	$60.5	$62.3	$64.2
41	Climate Change Costs, $/MWH	$7.83	$9.29	$10.76	$12.23	$13.70	$15.16	$16.63	$18.10	$19.57
42										
43	Integration Costs	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
44	Purchased Energy, Dollars	$754,705	$801,284	$849,349	$898,884	$950,074	$1,002,906	$1,057,436	$1,113,722	$1,171,822
45		$5,719	$6,758	$7,752	$9,325	$10,291	$11,197	$12,036	$12,805	$13,497
46	Purchased Demand, in kW	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
47	Demand Charge Rate, $ / kW-Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
48	Demand Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0

	K	L	M	N	O	P	Q	R	S	T
49	Total Cost of Purchased Power & REC's, Dollars	$760,425	$808,042	$857,101	$908,209	$960,365	$1,014,103	$1,069,472	$1,126,526	$1,185,319
50	Transmission Service	$93,833	$97,140	$100,564	$104,109	$107,779	$111,578	$115,511	$119,583	$123,799
51	Total Cost of Purchased Power, $ / Mwh	$59.39	$62.45	$65.55	$68.74	$71.93	$75.17	$78.45	$81.78	$85.16
52										
53	Rate for Sale of Excess Wind Power	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power	$481,318	$481,318	$481,318	$477,770	$477,770	$477,770	$477,770	$477,770	$477,770
55	Revenue from Sale of RECs	$0	$0	$0	$0	$0	$0	$0	$0	$0
56										
57	**Engine Plant**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
58	Existing Engine Generating Capacity	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW	$844	$869	$896	$922	$950	$979	$1,008	$1,038	$1,069
61	New Engine Total Capital Cost, $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**	2012	2013	2014	2015	2016	2017	2018	2019	2020
65	Energy Generated by Engines, MWh	650	650	650	650	650	650	650	650	650
66	Percentage from Natural Gas	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel	10%	10%	10%	10%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel	0%	0%	0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $	$ 57,908	$ 60,224	$ 62,633	$ 65,139	$ 67,744	$ 70,454	$ 73,272	$ 76,203	$ 79,251
71	Diesel Cost, $ as pilot fuel for gas	$ 20,148	$ 20,954	$ 21,792	$ 22,664	$ 23,570	$ 24,513	$ 25,494	$ 26,513	$ 27,574
72	Biodiesel Cost, $ as pilot or replacement for gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $	$ 78,056	$ 81,178	$ 84,425	$ 87,802	$ 91,315	$ 94,967	$ 98,766	$ 102,716	$ 106,825
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services	$ 139,124	$ 143,298	$ 147,597	$ 152,025	$ 156,586	$ 161,283	$ 166,122	$ 171,105	$ 176,239
77	Existing Plant Contractual Services	$ 158,994	$ 163,764	$ 168,677	$ 173,737	$ 178,949	$ 184,317	$ 189,847	$ 195,542	$ 201,409
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services	$0	$0	$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services	0	0	0	0	0	0	0	0	0
82										
83	**Cash receipts**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
84	Sales	$1,588,518	$1,716,712	$1,733,879	$1,891,315	$1,910,228	$2,083,677	$2,104,514	$2,125,559	$2,146,815
85	Rentals	$0	$0	$0	$0	$0	$0	$0	$0	$0
86	Security Lights	$3,740	$4,042	$4,082	$4,453	$4,497	$4,906	$4,955	$5,004	$5,054
87	Service Charge	$1,479	$1,598	$1,614	$1,761	$1,778	$1,940	$1,959	$1,979	$1,999
88	Materials sold	$1,991	$2,051	$2,112	$2,176	$2,241	$2,308	$2,377	$2,449	$2,522
89	Other	$168	$173	$178	$183	$189	$194	$200	$206	$213
90	Wind Power & REC Sales	$481,318	$481,318	$481,318	$477,770	$477,770	$477,770	$477,770	$477,770	$477,770
91	Total cash receipts	$2,077,214	$2,205,894	$2,223,184	$2,377,658	$2,396,704	$2,570,796	$2,591,776	$2,612,968	$2,634,373
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services	$139,124	$143,298	$147,597	$152,025	$156,586	$161,283	$166,122	$171,105	$176,239
95	Engine Plant Contractual Services	$158,994	$163,764	$168,677	$173,737	$178,949	$184,317	$189,847	$195,542	$201,409
96										
97	Wind Generator O&M, R&R	$118,342	$121,893	$125,549	$129,316	$133,195	$137,191	$141,307	$145,546	$149,913
98	Commodities	$19,520	$20,105	$20,709	$21,330	$21,970	$22,629	$23,308	$24,007	$24,727

	K	L	M	N	O	P	Q	R	S	T
99	Diesel fuel & oil	$18,648	$19,208	$19,784	$20,377	$20,989	$21,618	$22,267	$22,935	$23,623
100	Electricity, RECs, & Transmission Service	$854,257	$905,182	$957,665	$1,012,318	$1,068,144	$1,125,681	$1,184,984	$1,246,110	$1,309,117
101	Natural Gas	$57,908	$60,224	$62,633	$65,139	$67,744	$70,454	$73,272	$76,203	$79,251
102	Capital outlay	$0	$0	$0	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services	$187,958	$193,597	$199,405	$205,387	$211,549	$217,895	$224,432	$231,165	$238,100
105	Contractual Services	$13,320	$13,719	$14,131	$14,555	$14,991	$15,441	$15,904	$16,381	$16,873
106	Commodities	$53,265	$54,863	$56,509	$58,204	$59,950	$61,749	$63,601	$65,509	$67,474
107	Capital outlay	$2,379	$2,450	$2,523	$2,599	$2,677	$2,757	$2,840	$2,925	$3,013
108	**General & Administrative**									
109	Contractual Services	$3,271	$3,369	$3,470	$3,574	$3,682	$3,792	$3,906	$4,023	$4,144
110	Commodities	$0	$0	$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**	$420,000	$420,000	$420,000	$420,000	$420,000	$420,000	$420,000	$420,000	$420,000
112	**Reimbursed expenditures**	($8,503)	($8,759)	($9,021)	($9,292)	($9,571)	($9,858)	($10,154)	($10,458)	($10,772)
113	**Total Expenditures**	$2,038,483	$2,112,914	$2,189,631	$2,269,269	$2,350,855	$2,434,950	$2,521,636	$2,610,994	$2,703,110
114										
115	Receipts over (under) expenditures	$38,731	$92,980	$33,553	$108,390	$45,850	$135,845	$70,140	$1,974	($68,738)
116	Unencumbered cash (deficit) BOY	$263,455	$263,455	$263,455	$263,455	$263,455	$263,455	$274,280	$274,280	$274,280
117	Trasfer to City	($38,731)	($92,980)	($33,553)	($108,390)	($45,850)	($125,021)	($70,140)	($1,974)	$0
118	Unencumbered cash (deficit), EOY	$263,455	$263,455	$263,455	$263,455	$263,455	$274,280	$274,280	$274,280	$205,542
119										
120	**Retail Sales by Class**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
121										
122	Residential Mwh	8,662	8,748	8,836	8,924	9,013	9,103	9,194	9,286	9,379
123	Commercial Mwh	3,851	3,890	3,928	3,968	4,007	4,047	4,088	4,129	4,170
124	Furnished without charges & Losses	942	951	961	970	980	990	1,000	1,010	1,020
125	Total Mwh to System	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
126	Losses as a % of Sales	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year	0.0%	7.0%	0.0%	8.0%	0.0%	8.0%	0.0%	0.0%	0.0%
129	Residential Cost per kWh	$0.1277	$0.1366	$0.1366	$0.1475	$0.1475	$0.1593	$0.1593	$0.1593	$0.1593
130	Commercial Cost per kWh	$0.1254	$0.1341	$0.1341	$0.1449	$0.1449	$0.1565	$0.1565	$0.1565	$0.1565
131	Residential Revenue	$1,105,702	$1,194,932	$1,206,881	$1,316,466	$1,329,631	$1,450,361	$1,464,865	$1,479,513	$1,494,309
132	Commercial Revenue	$482,817	$521,780	$526,998	$574,849	$580,598	$633,316	$639,649	$646,045	$652,506
133	Total Sales Revenue	$1,588,518	$1,716,712	$1,733,879	$1,891,315	$1,910,228	$2,083,677	$2,104,514	$2,125,559	$2,146,815
134	Average Retail Sales Revenue ¢ per kWh	12.70	13.58	13.58	14.67	14.67	15.84	15.84	15.84	15.84
135	Residential Customers									
136	Commercial Customers									
137										
138	**Simplified Balance Sheet**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
139	Distribution System - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
140	Cumulative Investment	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation	$855,000	$997,500	$1,140,000	$1,282,500	$1,425,000	$1,567,500	$1,710,000	$1,852,500	$1,995,000
143	Net Depreciated Investment	$3,895,000	$3,752,500	$3,610,000	$3,467,500	$3,325,000	$3,182,500	$3,040,000	$2,897,500	$2,755,000
144										
145	Production Plant - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
146	Cumulative Investment	$8,800,000	$8,800,000	$8,800,000	$8,800,000	$8,800,000	$8,800,000	$8,800,000	$8,800,000	$8,800,000
147	Annual Depreciation	$352,000	$352,000	$352,000	$352,000	$352,000	$352,000	$352,000	$352,000	$352,000
148	Accumulated Depreciation	$1,608,000	$1,960,000	$2,312,000	$2,664,000	$3,016,000	$3,368,000	$3,720,000	$4,072,000	$4,424,000

	K	L	M	N	O	P	Q	R	S	T
149	Net Depreciated Investment	$7,192,000	$6,840,000	$6,488,000	$6,136,000	$5,784,000	$5,432,000	$5,080,000	$4,728,000	$4,376,000
150										
151	Total Utility Plant	$13,550,000	$13,550,000	$13,550,000	$13,550,000	$13,550,000	$13,550,000	$13,550,000	$13,550,000	$13,550,000
152	Less Accumulated Depreciation	$2,463,000	$2,957,500	$3,452,000	$3,946,500	$4,441,000	$4,935,500	$5,430,000	$5,924,500	$6,419,000
153	Total Net Utility Plant	$11,087,000	$10,592,500	$10,098,000	$9,603,500	$9,109,000	$8,614,500	$8,120,000	$7,625,500	$7,131,000
154	Current Assets & Other	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets	$11,187,000	$10,692,500	$10,198,000	$9,703,500	$9,209,000	$8,714,500	$8,220,000	$7,725,500	$7,231,000
156										
157	Total Equity	$6,517,000	$6,442,500	$6,368,000	$6,293,500	$6,219,000	$6,144,500	$6,070,000	$5,995,500	$5,921,000
158	Long-Term Liabilities	$4,620,000	$4,200,000	$3,780,000	$3,360,000	$2,940,000	$2,520,000	$2,100,000	$1,680,000	$1,260,000
159	Current Liabilities	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities	$4,670,000	$4,250,000	$3,830,000	$3,410,000	$2,990,000	$2,570,000	$2,150,000	$1,730,000	$1,310,000
161	Total Liabilities & Equity	$11,187,000	$10,692,500	$10,198,000	$9,703,500	$9,209,000	$8,714,500	$8,220,000	$7,725,500	$7,231,000

Summary 4

Strategy 3

Retain Utility

4.5 MW of Wind Generation

with No Financial Gift

	A	B	C	D	E	F	G	H	I	J
1	Strategy 3: 4.5 MW Wind, No Gift, 100% Green Power	Summary of Power Supply and Financial Modeling for Greensburg								
2		Preliminary and Confidential								
3			YEAR >>	2005	2006	2007	2008	2009	2010	2011
4	Load, Peak, Energy Prices									
5	Peak Load			0	4,489	0	2,479	3,360	3,444	3,478
6	Storage System Losses, MWH			0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH			15,622	15,474	7,414	9,496	12,867	13,189	13,321
8										
9	Natural Gas Cost $ / MMBTU					$7.00	$7.50	$7.80	$8.11	$8.44
10	Biodiesel Cost, $ / Gal					$2.50	$2.60	$2.70	$2.81	$2.92
11	Diesel Cost, $ / Gal					$2.75	$2.86	$2.97	$3.09	$3.22
12										
13	Wind Generation									
14	Wind Generation, Number of Turbines							3	3	3
15	Wind Generation, MW	1.50	Turbine Size, in MW		0.0%	Capital Contribution,	Gift =	4.50	4.50	4.50
16	Wind Generation, MWH	41.0%	Annual Capacity Factor Used			-0.30%	Array Delta	15,926	15,926	15,926
17	Wind Generation Capital Cost, $	1	2	3	4	< # of WTs		$9,112,500	$0	$0
18	Wind Generation O&M	$2,200	$2,100	$2,025	$1,975	< Total Cost per kW		$105,300	$108,459	$111,713
19	Wind Generation R&R & Warranty	$12	$ / kW in 2009		$26	$ / kW in 2009		$48,600	$50,058	$51,560
20										
21	Wind Generation as a % of Total Load							123.8%	120.7%	119.6%
22	Excess Wind Gen to Grid, %							46.1%	46.1%	42.7%
23	Excess Wind Gen to Grid, MWh							7,341	7,341	6,806
24										
25	Energy Storage System									
26	Energy Storage, MW			0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $			$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $			$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed			0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered			0	0	0	0	0	0	0
32	Energy Storage MWH Lost			0	0	0	0	0	0	0
33										
34	Purchases & Sales			2005	2006	2007	2008	2009	2010	2011
35	Purchases from Grid			14,823	15,296	7,364	8,846	12,217	12,539	12,671
36	Wind Power Sold to Grid						0	15,926	15,926	15,926
37	Equivalent Net Purchases (Sales to Grid)			14,823	15,296	7,364	8,846	(3,708)	(3,386)	(3,255)
38							0.0%	-28.8%	-25.7%	-24.4%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH						$45.0	$46.4	$47.7	$49.2
41	Climate Change Costs, $/MWH	Based on TAW 3 Scenario					$0.00	$0.00	$4.89	$6.36
42										
43	Integration Costs	260,000	MWh Pool Base				$0.0	$0.8	$0.8	$0.8
44	Purchased Energy, Dollars			$800,462	$769,694	$371,610	$398,086	$576,633	$670,597	$714,394
45	Cost of Renewable Energy Credits						$8,547	$0	$0	$0
46	Purchased Demand, in kW						2,479	3,360	3,444	3,478
47	Demand Charge Rate, $ / kW-Month						$0.00	$0.00	$0.00	$0.00
48	Demand Charges						$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	J
49	Total Cost of Purchased Power & REC's, Dollars			$857,584	$701,754	$371,610	$406,633	$576,633	$670,597	$714,394
50	Transmission Service						$60,000	$83,332	$87,551	$90,638
51	Total Cost of Purchased Power, $ / Mwh			$57.85	$45.88	$50.46	$45.97	$47.20	$53.48	$56.38
52										
53	Rate for Sale of Excess Wind Power	$45.00	per Mwh	0.0%	Escalator		$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power						$0	$716,656	$716,656	$716,656
55	Revenue from Sale of RECs	$0.00	per Mwh	0.0%	Escalator		$0	$0	$0	$0
56										
57	**Engine Plant**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
58	Existing Engine Generating Capacity			6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity			0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW			$0	$0	$0	$750	$773	$796	$820
61	New Engine Total Capital Cost, $			$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**			2005	2006	2007	1/2 Year	2009	2010	2011
65	Energy Generated by Engines, MWh			799	178	50	650	650	650	650
66	Percentage from Natural Gas			0.0%	0.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel			0%	0%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel			0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $			$ 69,539	$ 104,645	$ 10,395	$ 49,500	$ 51,480	$ 53,539	$ 55,681
71	Diesel Cost, $ as pilot fuel for gas			$ 14,093	$ -	$ 3,312	$ 17,223	$ 17,912	$ 18,628	$ 19,373
72	Biodiesel Cost, $ as pilot or replacement for gas			$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $			$ 83,632	$ 104,645	$ 13,707	$ 66,723	$ 69,392	$ 72,167	$ 75,054
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services			$ 206,081	$ 193,952	$ 120,010	$ 123,610	$ 127,319	$ 131,138	$ 135,072
77	Existing Plant Contractual Services			$ 171,345	$ 102,954	$ 54,860	$ 141,264	$ 145,502	$ 149,867	$ 154,363
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services			$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services			0	0	0	0	0	0	0
82										
83	**Cash receipts**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
84	Sales			$1,609,787	$1,791,549	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
85	Rentals			$0	$0	$0	$0	$0	$0	$0
86	Security Lights			$3,458	$4,218	$1,963	$2,514	$3,407	$3,492	$3,703
87	Service Charge			$1,328	$1,668	$776	$994	$1,347	$1,381	$1,464
88	Materials sold			$0	$3,335	$1,718	$1,769	$1,822	$1,877	$1,933
89	Other			$185	$96	$145	$149	$154	$158	$163
90	Wind Power & REC Sales			$0	$0	$0	$0	$716,656	$716,656	$716,656
91	Total cash receipts			$1,614,758	$1,800,866	$838,283	$1,073,242	$2,170,263	$2,206,628	$2,296,709
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services			$206,081	$193,952	$120,010	$123,610	$127,319	$131,138	$135,072
95	Engine Plant Contractual Services			$171,345	$102,954	$54,860	$141,264	$145,502	$149,867	$154,363
96										
97	Wind Generator O&M, R&R						$0	$153,900	$158,517	$163,273
98	Commodities			$14,969	$17,726	$16,838	$17,343	$17,863	$18,399	$18,951

	A	B	C	D	E	F	G	H	I	J
99	Diesel fuel & oil			$14,093	$0	$4,741	$8,533	$17,066	$17,578	$18,105
100	Electricity, RECs, & Transmission Service			$857,584	$701,754	$371,610	$466,633	$659,964	$758,148	$805,031
101	Natural Gas			$69,539	$104,645	$10,395	$49,500	$51,480	$53,539	$55,681
102	Capital outlay			$89	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services			$158,841	$155,983	$162,134	$166,998	$172,008	$177,169	$182,484
105	Contractual Services			$13,493	$8,817	$11,490	$11,834	$12,189	$12,555	$12,932
106	Commodities			$41,809	$47,408	$45,947	$47,325	$48,745	$50,207	$51,713
107	Capital outlay			$0	$3,984	$2,052	$2,113	$2,177	$2,242	$2,309
108	**General & Administrative**									
109	Contractual Services			$2,644	$2,835	$2,822	$2,906	$2,994	$3,083	$3,176
110	Commodities			$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**			$175,758	$175,758	$0	$0	$607,500	$607,500	$607,500
112	**Reimbursed expenditures**			($9,928)	($4,315)	($7,335)	($7,555)	($7,782)	($8,015)	($8,256)
113	**Total Expenditures**			$1,716,317	$1,511,501	$795,562	$1,030,505	$2,010,925	$2,131,928	$2,202,334
114										
115	Receipts over (under) expenditures			($101,559)	$289,365	$42,721	$42,737	$159,338	$74,700	$94,375
116	Unencumbered cash (deficit) BOY			$9,040	($92,519)	$196,846	$189,546	$189,546	$262,071	$262,071
117	Trasfer to City			$0	$0	($50,021)	($42,737)	($86,813)	($74,700)	($94,367)
118	Unencumbered cash (deficit), EOY			($92,519)	$196,846	$189,546	$189,546	$262,071	$262,071	$262,079
119										
120	**Retail Sales by Class**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
121										
122	Residential Mwh			10,338	9,533	4,773	6,113	8,284	8,491	8,576
123	Commercial Mwh			4,303	4,288	2,122	2,718	3,683	3,775	3,813
124	Furnished without charges & Losses			981	1,653	519	665	901	923	932
125	Total Mwh to System			15,622	15,474	7,414	9,496	12,867	13,189	13,321
126	Losses as a % of Sales			6.7%	12.0%	10.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.0%
129	Residential Cost per kWh			$0.1115	$0.1216	$0.1216	$0.1216	$0.1216	$0.1216	$0.1277
130	Commercial Cost per kWh			$0.1106	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1254
131	Residential Revenue			$1,153,000	$1,159,000	$580,292	$743,262	$1,007,112	$1,032,300	$1,094,754
132	Commercial Revenue			$476,000	$512,000	$253,391	$324,553	$439,766	$450,765	$478,036
133	Total Sales Revenue			$1,629,000	$1,671,000	$833,682	$1,067,815	$1,446,878	$1,483,065	$1,572,790
134	Average Retail Sales Revenue ¢ per kWh			11.13	12.09	12.09	12.09	12.09	12.09	12.70
135	Residential Customers			792	783					
136	Commercial Customers			132	148					
137										
138	**Simplified Balance Sheet**			**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
139	Distribution System - New Investment					$4,500,000	$0	$0	$0	$0
140	Cumulative Investment	Existing Distribution that Survived>			$250,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation					$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation					$142,500	$285,000	$427,500	$570,000	$712,500
143	Net Depreciated Investment					$4,607,500	$4,465,000	$4,322,500	$4,180,000	$4,037,500
144										
145	Production Plant - New Investment					$0	$0	$9,112,500	$0	$0
146	Cumulative Investment			Existing Diesel Plant >	$2,500,000	$2,500,000	$2,500,000	$11,612,500	$11,612,500	$11,612,500
147	Annual Depreciation					$100,000	$100,000	$464,500	$464,500	$464,500
148	Accumulated Depreciation					$100,000	$200,000	$664,500	$1,129,000	$1,593,500

	A	B	C	D	E	F	G	H	I	J
149	Net Depreciated Investment					$2,400,000	$2,300,000	$10,948,000	$10,483,500	$10,019,000
150										
151	Total Utility Plant					$7,250,000	$7,250,000	$16,362,500	$16,362,500	$16,362,500
152	Less Accumulated Depreciation					$242,500	$485,000	$1,092,000	$1,699,000	$2,306,000
153	Total Net Utility Plant					$7,007,500	$6,765,000	$15,270,500	$14,663,500	$14,056,500
154	Current Assets & Other					$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets					$7,107,500	$6,865,000	$15,370,500	$14,763,500	$14,156,500
156										
157	Total Equity					$7,057,500	$6,815,000	$6,815,500	$6,816,000	$6,816,500
158	Long-Term Liabilities					$0	$0	$8,505,000	$7,897,500	$7,290,000
159	Current Liabilities					$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities					$50,000	$50,000	$8,555,000	$7,947,500	$7,340,000
161	Total Liabilities & Equity					$7,107,500	$6,865,000	$15,370,500	$14,763,500	$14,156,500

	K	L	M	N	O	P	Q	R	S	T
1	**Strategy 3: 4.5 MW Wind, No**	**Summary of Power Supply and Financial Modeling for Greensburg**								
2	**Gift, 100% Green Power**	**Preliminary and Confidential**								
3		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
4	**Load, Peak, Energy Prices**									
5	Peak Load	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
6	Storage System Losses, MWH	0	0	0	0	0	0	0	0	0
7	Total Energy to System, Including Losses, MWH	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
8										
9	Natural Gas Cost $ / MMBTU	$8.77	$9.12	$9.49	$9.87	$10.26	$10.67	$11.10	$11.55	$12.01
10	Biodiesel Cost, $ / Gal	$3.04	$3.16	$3.29	$3.42	$3.56	$3.70	$3.85	$4.00	$4.16
11	Diesel Cost, $ / Gal	$3.35	$3.48	$3.62	$3.76	$3.91	$4.07	$4.23	$4.40	$4.58
12										
13	**Wind Generation**									
14	Wind Generation, Number of Turbines	3	3	3	3	3	3	3	3	3
15	Wind Generation, MW	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
16	Wind Generation, MWH	15,926	15,926	15,926	15,748	15,748	15,748	15,748	15,748	15,748
17	Wind Generation Capital Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind Generation O&M	$115,064	$118,516	$122,072	$125,734	$129,506	$133,391	$137,393	$141,514	$145,760
19	Wind Generation R&R & Warranty	$53,107	$54,700	$56,341	$58,031	$59,772	$61,565	$63,412	$65,314	$67,274
20										
21	Wind Generation as a % of Total Load	118.4%	117.2%	116.0%	113.6%	112.5%	111.4%	110.3%	109.2%	108.1%
22	Excess Wind Gen to Grid, %	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	39.0%	39.0%
23	Excess Wind Gen to Grid, MWh	6,806	6,806	6,806	6,730	6,730	6,730	6,730	6,144	6,144
24										
25	**Energy Storage System**									
26	Energy Storage, MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Energy Storage Capital Cost, Mil $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
28	Energy Storage Fixed Charges, Mil $	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Energy Storage O&M Cost, $	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Energy Storage MWH Net Consumed	0	0	0	0	0	0	0	0	0
31	Energy Storage MWH Net Delivered	0	0	0	0	0	0	0	0	0
32	Energy Storage MWH Lost	0	0	0	0	0	0	0	0	0
33										
34	**Purchases & Sales**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
35	Purchases from Grid	12,804	12,939	13,075	13,212	13,351	13,491	13,632	13,775	13,919
36	Wind Power Sold to Grid	15,926	15,926	15,926	15,748	15,748	15,748	15,748	15,748	15,748
37	Equivalent Net Purchases (Sales to Grid)	(3,121)	(2,987)	(2,851)	(2,536)	(2,398)	(2,258)	(2,116)	(1,973)	(1,829)
38		-23.2%	-22.0%	-20.8%	-18.3%	-17.1%	-16.0%	-14.8%	-13.7%	-12.6%
39	Equivalent Net Purchases as a % of Load									
40	Energy Charge Rate, $/MWH	$50.6	$52.2	$53.7	$55.3	$57.0	$58.7	$60.5	$62.3	$64.2
41	Climate Change Costs, $/MWH	$7.83	$9.29	$10.76	$12.23	$13.70	$15.16	$16.63	$18.10	$19.57
42										
43	Integration Costs	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
44	Purchased Energy, Dollars	$759,584	$806,214	$854,331	$903,799	$955,041	$1,007,925	$1,062,508	$1,118,846	$1,177,001
45		$0	$0	$0	$0	$0	$0	$0	$0	$0
46	Purchased Demand, in kW	3,513	3,548	3,583	3,619	3,655	3,692	3,729	3,766	3,804
47	Demand Charge Rate, $ / kW-Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
48	Demand Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0

	K	L	M	N	O	P	Q	R	S	T
49	Total Cost of Purchased Power & REC's, Dollars	$759,584	$806,214	$854,331	$903,799	$955,041	$1,007,925	$1,062,508	$1,118,846	$1,177,001
50	Transmission Service	$93,833	$97,140	$100,564	$104,109	$107,779	$111,578	$115,511	$119,583	$123,799
51	Total Cost of Purchased Power, $ / Mwh	$59.32	$62.31	$65.34	$68.41	$71.53	$74.71	$77.94	$81.22	$84.56
52										
53	Rate for Sale of Excess Wind Power	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
54	Revenue from Sale of Wind Power	$716,656	$716,656	$716,656	$708,673	$708,673	$708,673	$708,673	$708,673	$708,673
55	Revenue from Sale of RECs	$0	$0	$0	$0	$0	$0	$0	$0	$0
56										
57	**Engine Plant**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
58	Existing Engine Generating Capacity	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
59	New Engine Generating Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	New Engine Capital Cost per kW	$844	$869	$896	$922	$950	$979	$1,008	$1,038	$1,069
61	New Engine Total Capital Cost, $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	New Engine Fixed Charges, $	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
63										
64	**Engine Plant Fuel Costs**	2012	2013	2014	2015	2016	2017	2018	2019	2020
65	Energy Generated by Engines, MWh	650	650	650	650	650	650	650	650	650
66	Percentage from Natural Gas	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
67	Percentage from Diesel	10%	10%	10%	10%	10%	10%	10%	10%	10%
68	Percentage from Biodiesel	0%	0%	0%	0%	0%	0%	0%	0%	0%
69										
70	Natural Gas Cost, $	$ 57,908	$ 60,224	$ 62,633	$ 65,139	$ 67,744	$ 70,454	$ 73,272	$ 76,203	$ 79,251
71	Diesel Cost, $ as pilot fuel for gas	$ 20,148	$ 20,954	$ 21,792	$ 22,664	$ 23,570	$ 24,513	$ 25,494	$ 26,513	$ 27,574
72	Biodiesel Cost, $ as pilot or replacement for gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Total Fuel Cost, $	$ 78,056	$ 81,178	$ 84,425	$ 87,802	$ 91,315	$ 94,967	$ 98,766	$ 102,716	$ 106,825
74	**Existing Engine Plant O&M**									
75										
76	Existing Plant Personal Services	$ 139,124	$ 143,298	$ 147,597	$ 152,025	$ 156,586	$ 161,283	$ 166,122	$ 171,105	$ 176,239
77	Existing Plant Contractual Services	$ 158,994	$ 163,764	$ 168,677	$ 173,737	$ 178,949	$ 184,317	$ 189,847	$ 195,542	$ 201,409
78										
79	**New Engine Plant O&M**									
80	New Plant Personal Services	$0	$0	$0	$0	$0	$0	$0	$0	$0
81	New Plant Contractual Services	0	0	0	0	0	0	0	0	0
82										
83	**Cash receipts**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
84	Sales	$1,588,518	$1,716,712	$1,733,879	$1,891,315	$1,910,228	$2,083,677	$2,104,514	$2,125,559	$2,146,815
85	Rentals	$0	$0	$0	$0	$0	$0	$0	$0	$0
86	Security Lights	$3,740	$4,042	$4,082	$4,453	$4,497	$4,906	$4,955	$5,004	$5,054
87	Service Charge	$1,479	$1,598	$1,614	$1,761	$1,778	$1,940	$1,959	$1,979	$1,999
88	Materials sold	$1,991	$2,051	$2,112	$2,176	$2,241	$2,308	$2,377	$2,449	$2,522
89	Other	$168	$173	$178	$183	$189	$194	$200	$206	$213
90	Wind Power & REC Sales	$716,656	$716,656	$716,656	$708,673	$708,673	$708,673	$708,673	$708,673	$708,673
91	Total cash receipts	$2,312,552	$2,441,231	$2,458,521	$2,608,561	$2,627,607	$2,801,699	$2,822,679	$2,843,870	$2,865,276
92	**Expenditures**									
93	**Production**									
94	Engine Plant Personal Services	$139,124	$143,298	$147,597	$152,025	$156,586	$161,283	$166,122	$171,105	$176,239
95	Engine Plant Contractual Services	$158,994	$163,764	$168,677	$173,737	$178,949	$184,317	$189,847	$195,542	$201,409
96										
97	Wind Generator O&M, R&R	$168,171	$173,216	$178,412	$183,765	$189,278	$194,956	$200,805	$206,829	$213,034
98	Commodities	$19,520	$20,105	$20,709	$21,330	$21,970	$22,629	$23,308	$24,007	$24,727

	K	L	M	N	O	P	Q	R	S	T
99	Diesel fuel & oil	$18,648	$19,208	$19,784	$20,377	$20,989	$21,618	$22,267	$22,935	$23,623
100	Electricity, RECs, & Transmission Service	$853,417	$903,354	$954,895	$1,007,908	$1,062,820	$1,119,503	$1,178,019	$1,238,430	$1,300,799
101	Natural Gas	$57,908	$60,224	$62,633	$65,139	$67,744	$70,454	$73,272	$76,203	$79,251
102	Capital outlay	$0	$0	$0	$0	$0	$0	$0	$0	$0
103	**Transmission & Distribution**									
104	Personal Services	$187,958	$193,597	$199,405	$205,387	$211,549	$217,895	$224,432	$231,165	$238,100
105	Contractual Services	$13,320	$13,719	$14,131	$14,555	$14,991	$15,441	$15,904	$16,381	$16,873
106	Commodities	$53,265	$54,863	$56,509	$58,204	$59,950	$61,749	$63,601	$65,509	$67,474
107	Capital outlay	$2,379	$2,450	$2,523	$2,599	$2,677	$2,757	$2,840	$2,925	$3,013
108	**General & Administrative**									
109	Contractual Services	$3,271	$3,369	$3,470	$3,574	$3,682	$3,792	$3,906	$4,023	$4,144
110	Commodities	$0	$0	$0	$0	$0	$0	$0	$0	$0
111	**Transfer to electric debt service**	$607,500	$607,500	$607,500	$607,500	$607,500	$607,500	$607,500	$607,500	$607,500
112	**Reimbursed expenditures**	($8,503)	($8,759)	($9,021)	($9,292)	($9,571)	($9,858)	($10,154)	($10,458)	($10,772)
113	**Total Expenditures**	$2,274,970	$2,349,908	$2,427,224	$2,506,808	$2,589,113	$2,674,038	$2,761,669	$2,852,097	$2,945,413
114										
115	Receipts over (under) expenditures	$37,581	$91,323	$31,298	$101,753	$38,494	$127,661	$61,010	($8,226)	($80,138)
116	Unencumbered cash (deficit) BOY	$262,079	$262,079	$262,079	$262,079	$262,079	$262,079	$264,719	$264,719	$256,493
117	Trasfer to City	($37,581)	($91,323)	($31,298)	($101,753)	($38,494)	($125,021)	($61,010)	$0	$0
118	Unencumbered cash (deficit), EOY	$262,079	$262,079	$262,079	$262,079	$262,079	$264,719	$264,719	$256,493	$176,355
119										
120	**Retail Sales by Class**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
121										
122	Residential Mwh	8,662	8,748	8,836	8,924	9,013	9,103	9,194	9,286	9,379
123	Commercial Mwh	3,851	3,890	3,928	3,968	4,007	4,047	4,088	4,129	4,170
124	Furnished without charges & Losses	942	951	961	970	980	990	1,000	1,010	1,020
125	Total Mwh to System	13,454	13,589	13,725	13,862	14,001	14,141	14,282	14,425	14,569
126	Losses as a % of Sales	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
127										
128	Rate Change by Year	0.0%	7.0%	0.0%	8.0%	0.0%	8.0%	0.0%	0.0%	0.0%
129	Residential Cost per kWh	$0.1277	$0.1366	$0.1366	$0.1475	$0.1475	$0.1593	$0.1593	$0.1593	$0.1593
130	Commercial Cost per kWh	$0.1254	$0.1341	$0.1341	$0.1449	$0.1449	$0.1565	$0.1565	$0.1565	$0.1565
131	Residential Revenue	$1,105,702	$1,194,932	$1,206,881	$1,316,466	$1,329,631	$1,450,361	$1,464,865	$1,479,513	$1,494,309
132	Commercial Revenue	$482,817	$521,780	$526,998	$574,849	$580,598	$633,316	$639,649	$646,045	$652,506
133	Total Sales Revenue	$1,588,518	$1,716,712	$1,733,879	$1,891,315	$1,910,228	$2,083,677	$2,104,514	$2,125,559	$2,146,815
134	Average Retail Sales Revenue ¢ per kWh	12.70	13.58	13.58	14.67	14.67	15.84	15.84	15.84	15.84
135	Residential Customers									
136	Commercial Customers									
137										
138	**Simplified Balance Sheet**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	2019	2020
139	Distribution System - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
140	Cumulative Investment	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000	$4,750,000
141	Annual Depreciation	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500	$142,500
142	Accumulated Depreciation	$855,000	$997,500	$1,140,000	$1,282,500	$1,425,000	$1,567,500	$1,710,000	$1,852,500	$1,995,000
143	Net Depreciated Investment	$3,895,000	$3,752,500	$3,610,000	$3,467,500	$3,325,000	$3,182,500	$3,040,000	$2,897,500	$2,755,000
144										
145	Production Plant - New Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0
146	Cumulative Investment	$11,612,500	$11,612,500	$11,612,500	$11,612,500	$11,612,500	$11,612,500	$11,612,500	$11,612,500	$11,612,500
147	Annual Depreciation	$464,500	$464,500	$464,500	$464,500	$464,500	$464,500	$464,500	$464,500	$464,500
148	Accumulated Depreciation	$2,058,000	$2,522,500	$2,987,000	$3,451,500	$3,916,000	$4,380,500	$4,845,000	$5,309,500	$5,774,000

	K	L	M	N	O	P	Q	R	S	T
149	Net Depreciated Investment	$9,554,500	$9,090,000	$8,625,500	$8,161,000	$7,696,500	$7,232,000	$6,767,500	$6,303,000	$5,838,500
150										
151	Total Utility Plant	$16,362,500	$16,362,500	$16,362,500	$16,362,500	$16,362,500	$16,362,500	$16,362,500	$16,362,500	$16,362,500
152	Less Accumulated Depreciation	$2,913,000	$3,520,000	$4,127,000	$4,734,000	$5,341,000	$5,948,000	$6,555,000	$7,162,000	$7,769,000
153	Total Net Utility Plant	$13,449,500	$12,842,500	$12,235,500	$11,628,500	$11,021,500	$10,414,500	$9,807,500	$9,200,500	$8,593,500
154	Current Assets & Other	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
155	Total Assets	$13,549,500	$12,942,500	$12,335,500	$11,728,500	$11,121,500	$10,514,500	$9,907,500	$9,300,500	$8,693,500
156										
157	Total Equity	$6,817,000	$6,817,500	$6,818,000	$6,818,500	$6,819,000	$6,819,500	$6,820,000	$6,820,500	$6,821,000
158	Long-Term Liabilities	$6,682,500	$6,075,000	$5,467,500	$4,860,000	$4,252,500	$3,645,000	$3,037,500	$2,430,000	$1,822,500
159	Current Liabilities	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000	$50,000
160	Total Liabilities	$6,732,500	$6,125,000	$5,517,500	$4,910,000	$4,302,500	$3,695,000	$3,087,500	$2,480,000	$1,872,500
161	Total Liabilities & Equity	$13,549,500	$12,942,500	$12,335,500	$11,728,500	$11,121,500	$10,514,500	$9,907,500	$9,300,500	$8,693,500

Attachment 2
Correlation of Wind Power and City Loads

A simulation of correlation between the City load and wind generation output was made to estimate the amount of time that the wind turbines would generate more power than used by the City. The simulation is based on the wind turbines generating the same amount of energy as the City uses. An annual city load of 13 million kWh was used, which required about 3.6 MW of wind generation at a 41% annual capacity factor. Load and wind generation data was taken from the municipal utility at Algona, Iowa which has a 2.25 MW wind farm. Both load and generation levels were scaled to match Greensburg's annual energy needs. Since Algona has a higher annual load factor, the simulation resulted in slightly lower peaks than Greensburg would have. However, the annual energy needs were adjusted to match Greensburg's projected full recovery energy needs. Each of the following four graphs show the hourly load (blue line), hourly generation (green line), and the excess wind power that would flow back to the grid (red dots labeled "Sold") for a three-month period.

FIGURE 1

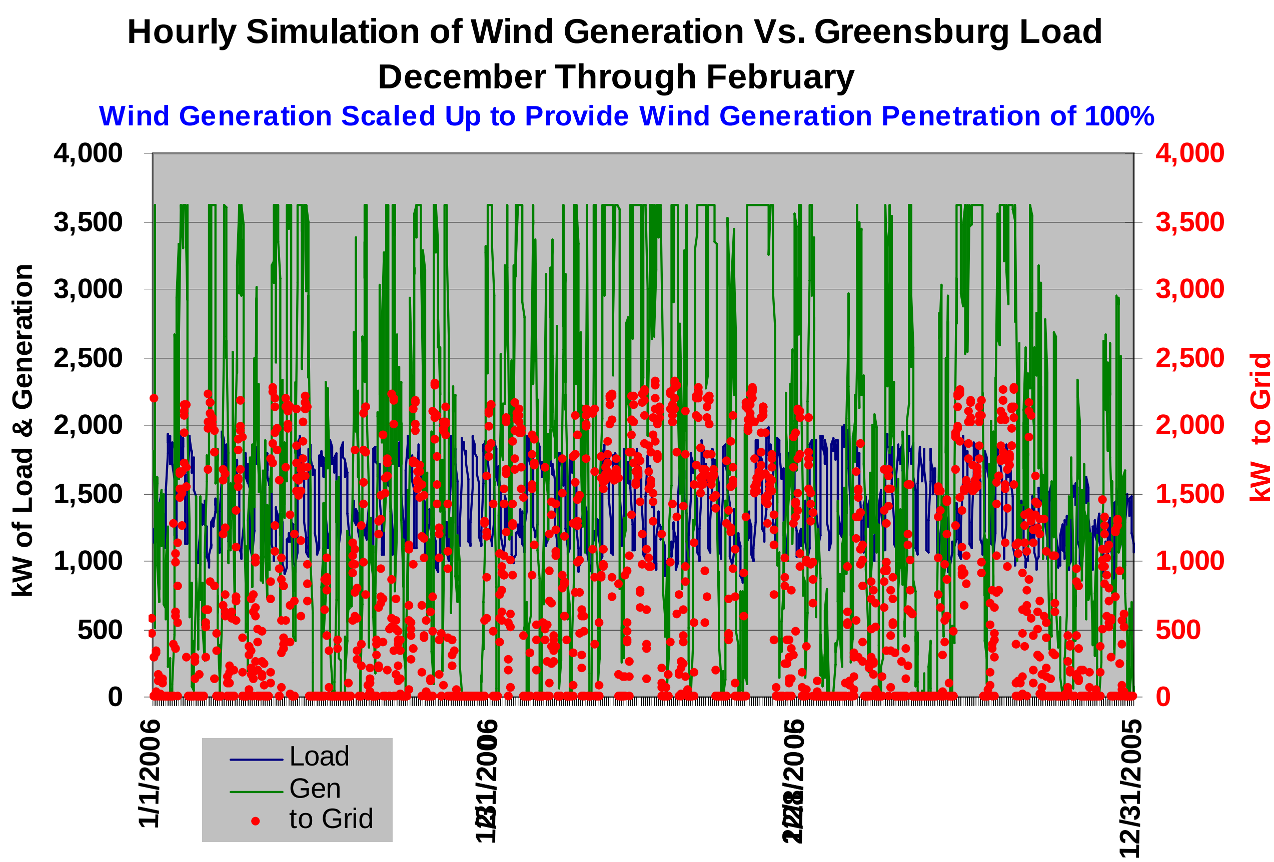


FIGURE 2

Hourly Simulation of Wind Generation Vs. Greensburg Load
March Through May

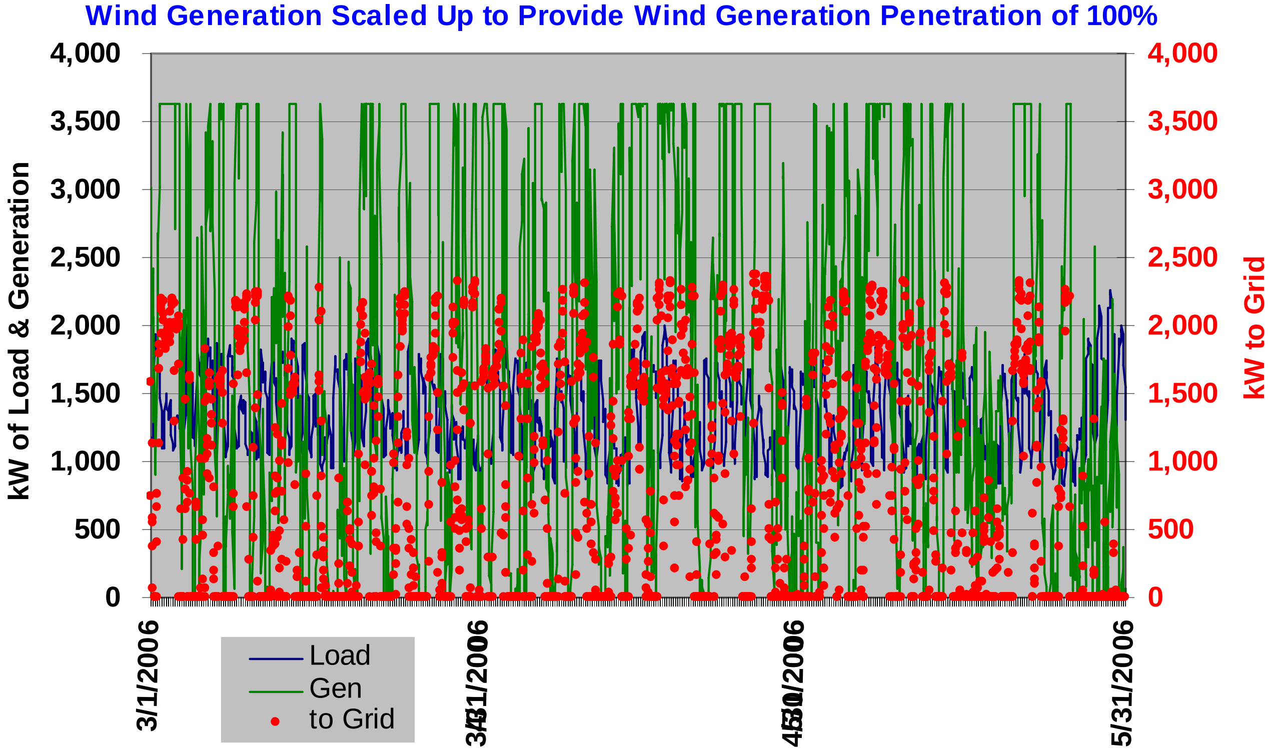


FIGURE 3

Hourly Simulation of Wind Generation Vs. Greensburg Load
June Through August

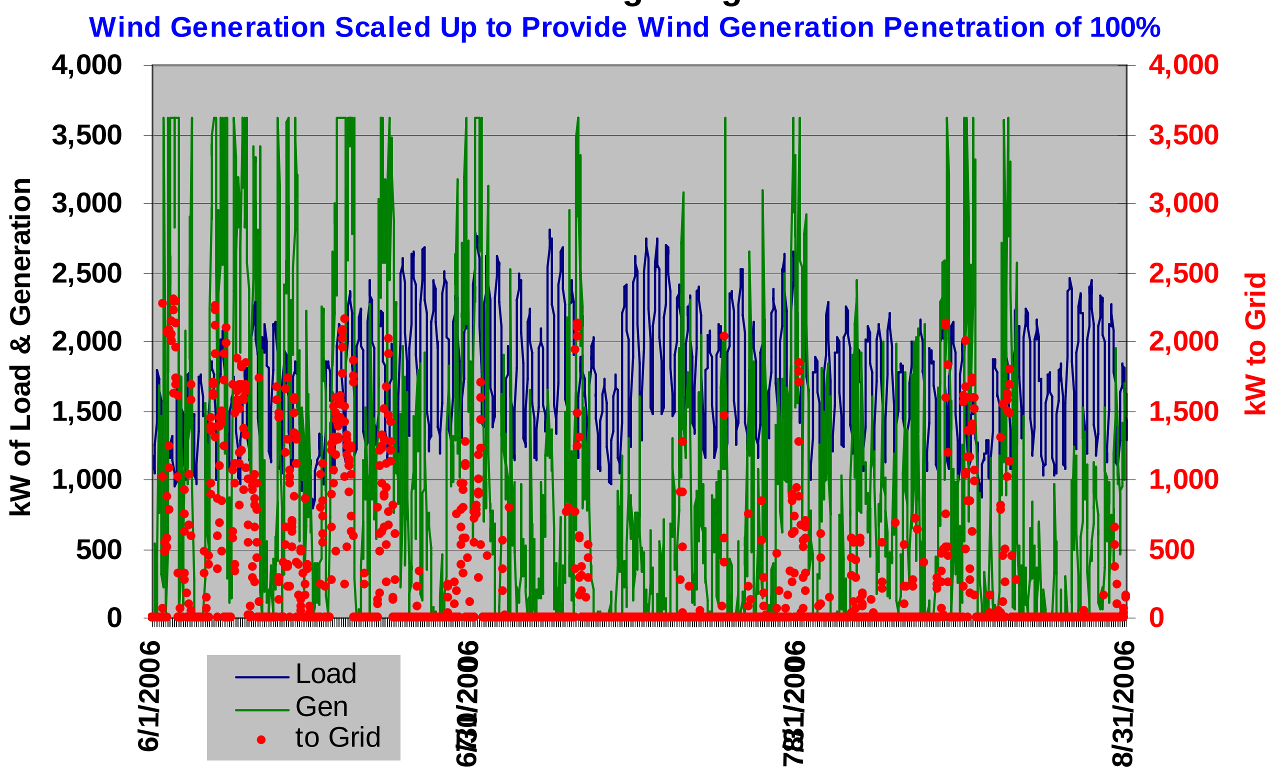


FIGURE 4

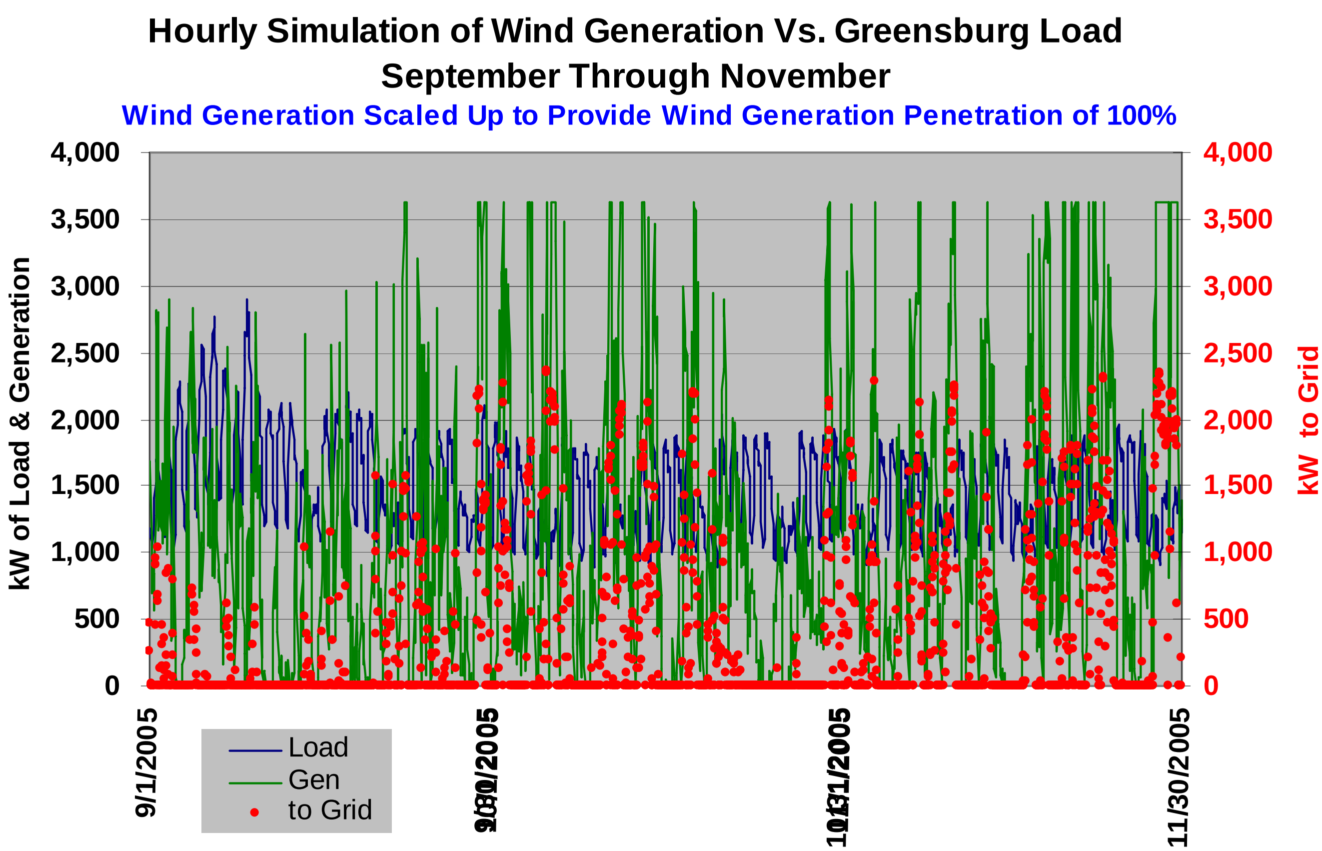

Hourly Simulation of Wind Generation Vs. Greensburg Load
September Through November
Wind Generation Scaled Up to Provide Wind Generation Penetration of 100%
kW of Load & Generation
kW to Grid
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
9/1/2005
11/30/2005
Load
Gen
to Grid

Figure 5 below shows the amount of wind generation during a year that would be in excess of a city's load for various wind generation penetration levels. For example, if the local "behind the meter" wind generation produces the same amount of energy as this city uses during the year (100% penetration level on "X" axis), then 39% of the wind energy would flow back to the grid. This is because the wind turbines would be producing more power than the city would need at various times. This implies that the city would have to likewise import 39% of its energy from the grid during those times when the wind turbines weren't generating enough power.

FIGURE 5

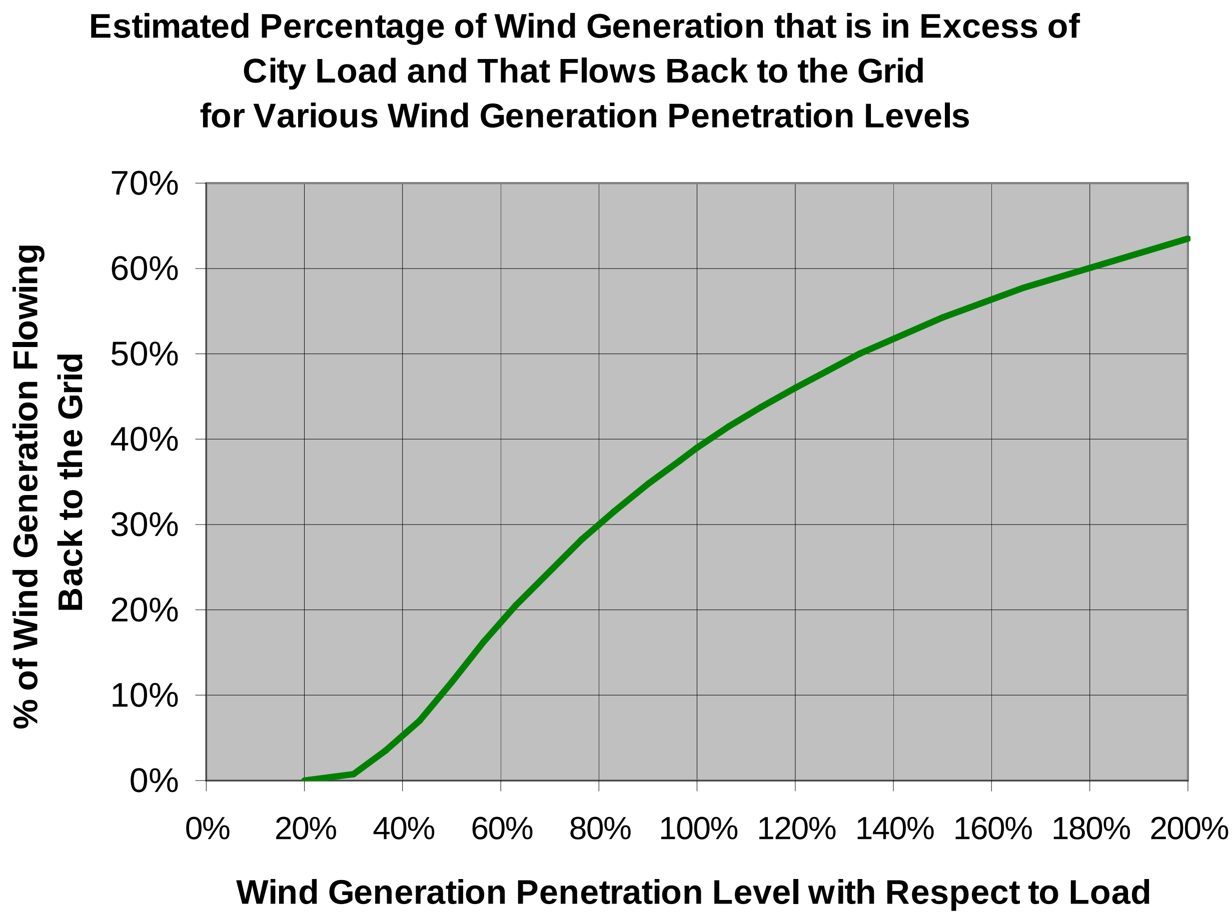


Figure 5 was based on time-synchronized city load and wind generation levels for one year of data from Algona, Iowa. Slightly different results would be obtained using data from different specific years. There are eight full years of time-synchronized data for this project.

D.6 Presentation: Refined Wind Speed Maps for Greensburg

Trudy Forsyth
National Renewable Energy Laboratory

Thomas A. Wind
Wind Utility Consulting

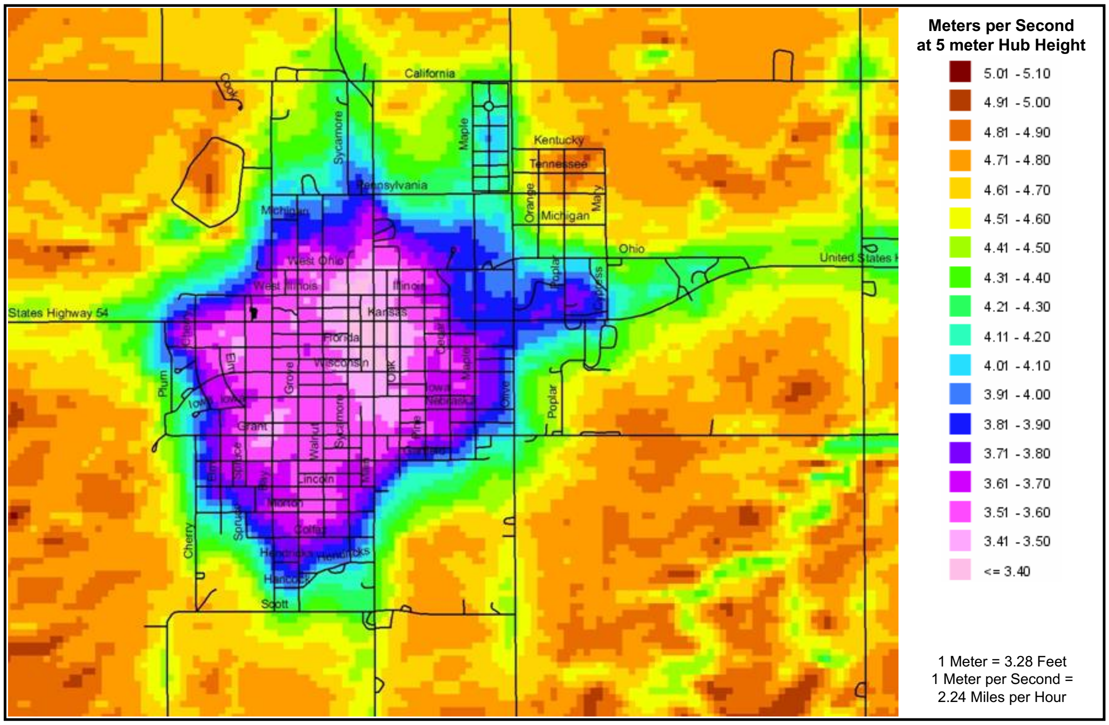
Refined Wind Speed Maps for Greensburg

- More refined mean annual wind speed maps were developed for Greensburg to help city residents determine how many kWh wind turbines would generate over the course of a year.
- These refined wind speed maps used much more detailed land use data from the USGS. All of this land use data, which includes tree cover, was based on data prior to the tornado.
- The following slides show the estimated wind speeds around Greensburg at 5, 10, 15, 20, 25, 30, and 50 meter heights above ground. One meter is 3.3 feet.
- These average annual wind speeds can be used with wind turbine manufacturer's data to estimate the annual kWh generation from a wind turbine.

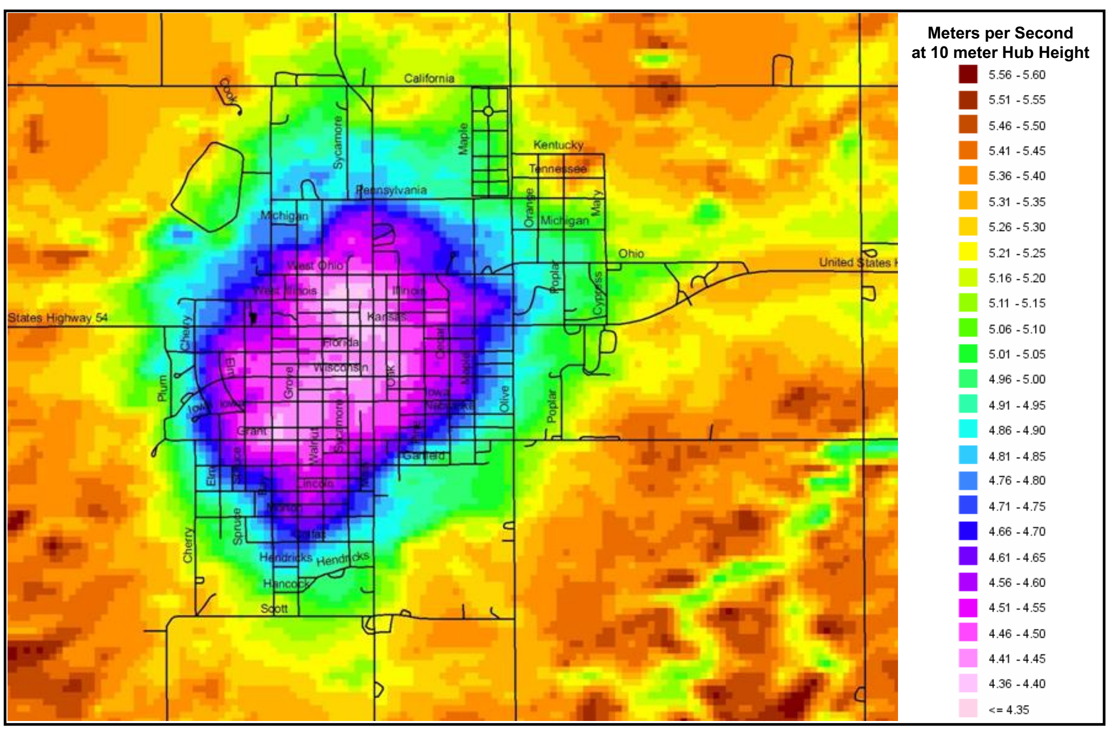
Thomas A. Wind
Wind Utility Consulting, PC
February 18, 2008

Estimate of Impact of Reduced Tree Cover and Fewer Buildings on Wind Speeds in Greensburg

- Trees and buildings slow winds down, especially at lower wind turbine hub heights typically used for smaller wind turbines.
- All of the preceding maps were based on tree cover and buildings that existed prior to the tornado. Since many trees and buildings in Greensburg were lost, the winds will be faster than they were prior to the tornado.
- A rough estimate of the higher wind speeds was made at the 20 meter hub height, or 65 feet with today's reduced hub heights.
- In general, the average wind speed over the course of a year is perhaps 5% higher at 65 feet with today's reduced tree cover. The percentage difference is more at lower hub heights than higher hub heights



Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Preliminary Wind Speed Estimates around Greensburg, Kansas**	This is a detailed high resolution mean annual wind speed map developed by Wind Utility Consulting, PC. It is based in part on the Kansas Corporation wind speed map.



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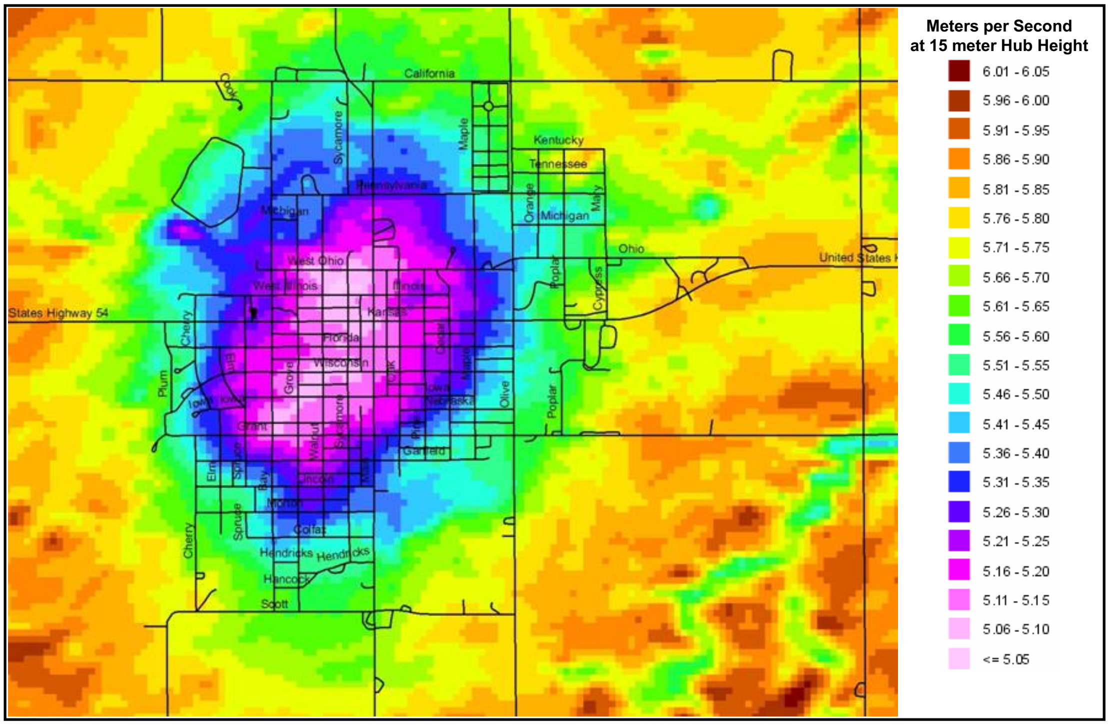
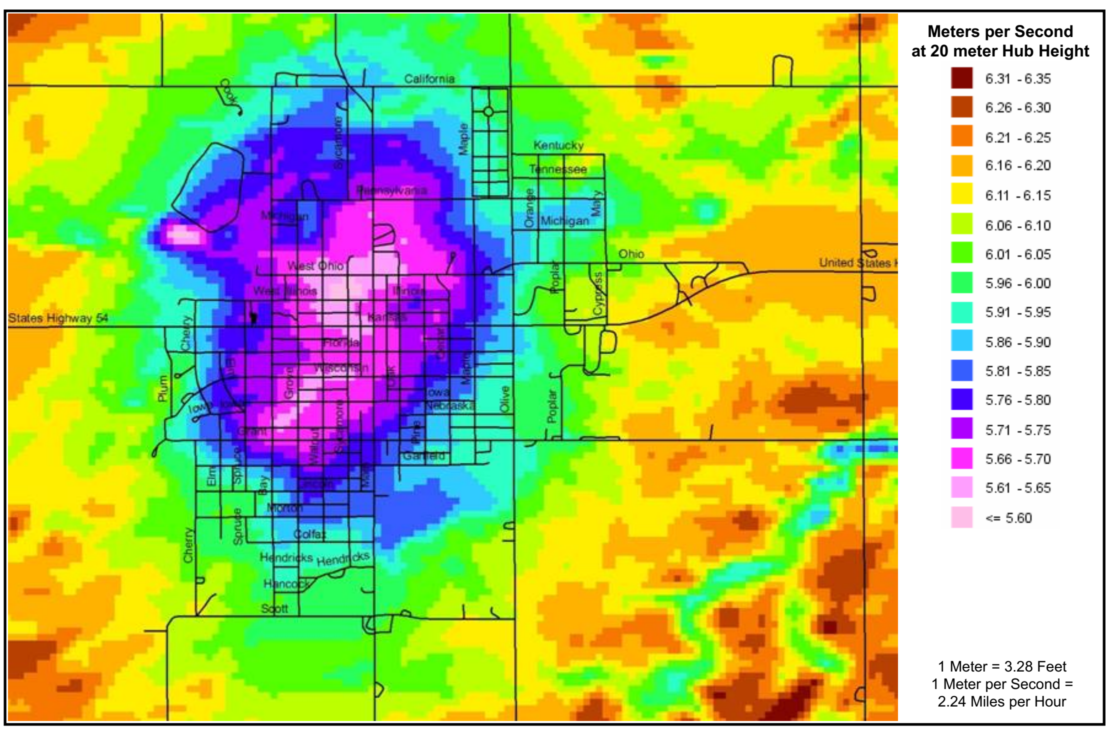
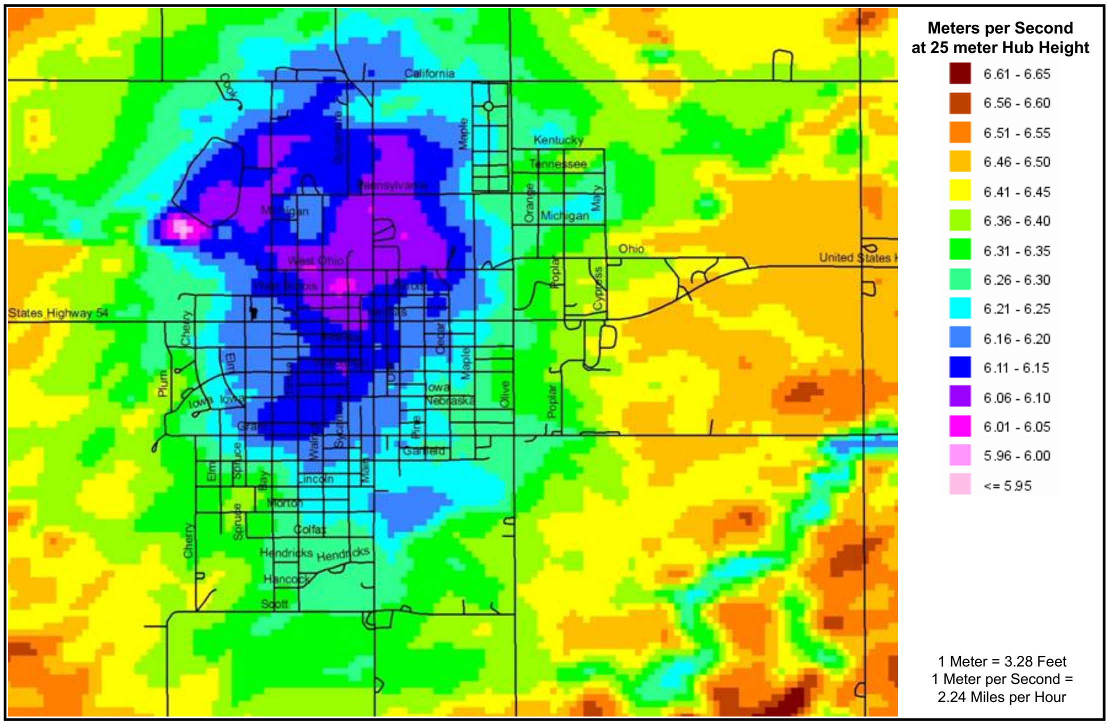


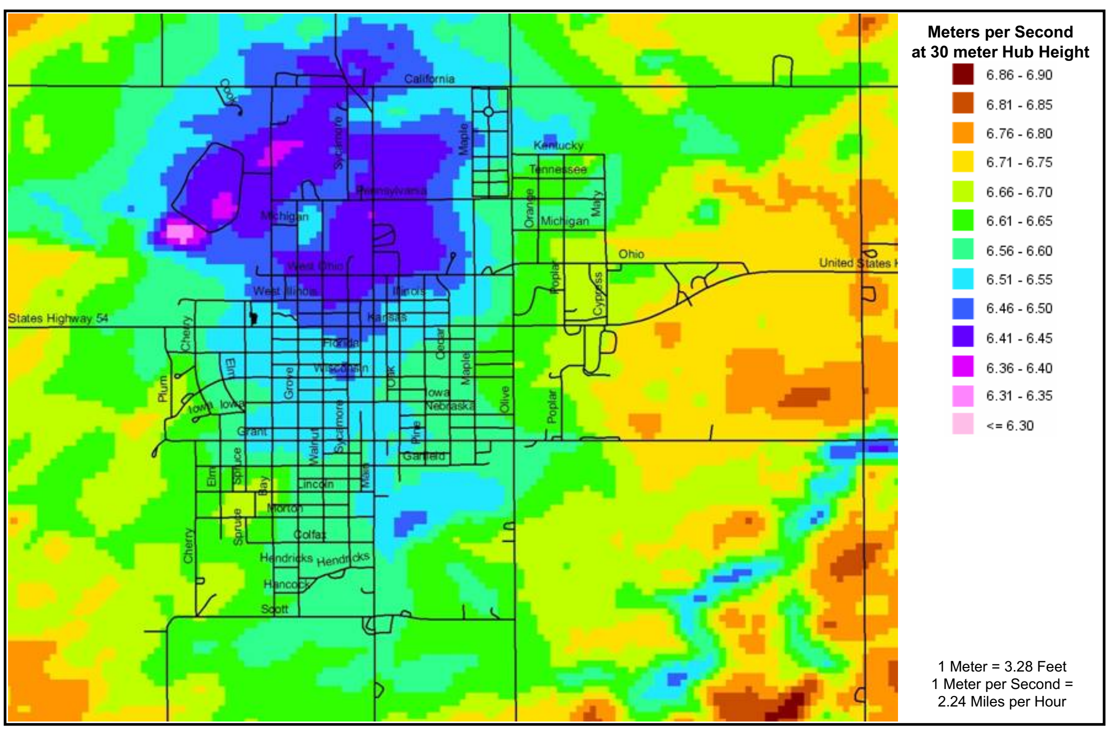
Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Preliminary Wind Speed Estimates around Greensburg, Kansas**	This is a detailed high resolution mean annual wind speed map developed by Wind Utility Consulting, PC. It is based in part on the Kansas Corporation wind speed map.



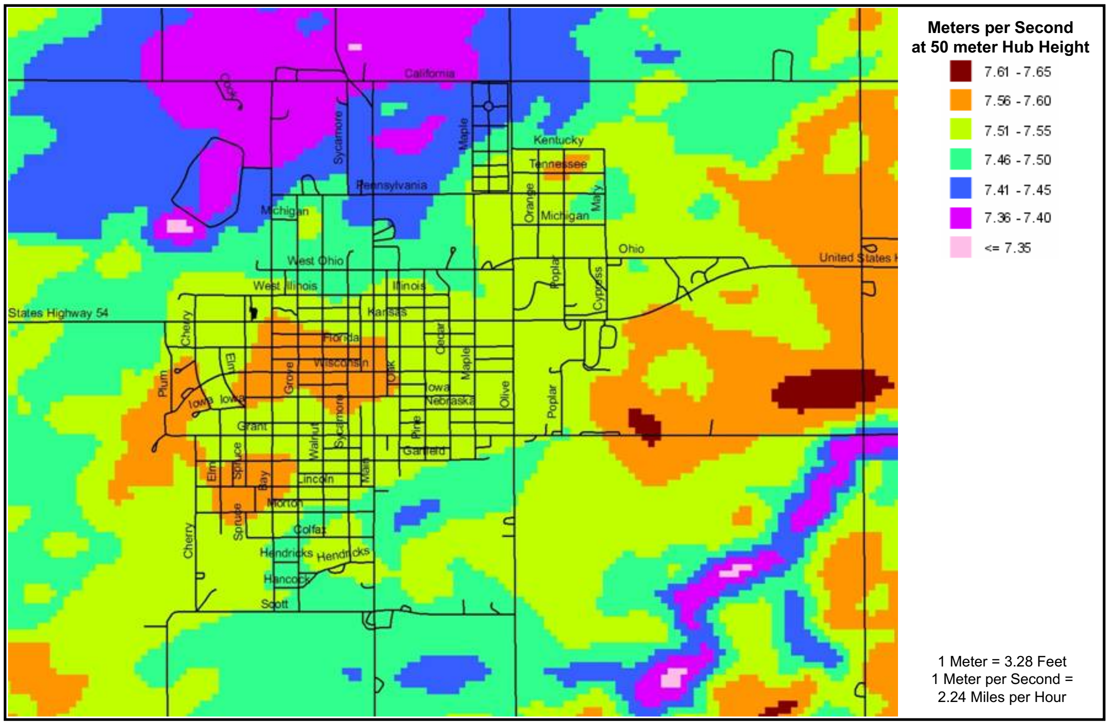
Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Preliminary Wind Speed Estimates around Greensburg, Kansas**	This is a detailed high resolution mean annual wind speed map developed by Wind Utility Consulting, PC. It is based in part on the Kansas Corporation wind speed map.



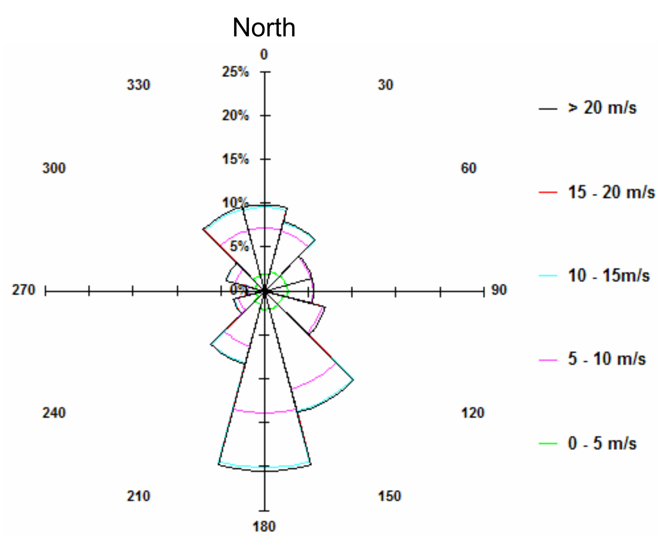
Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Preliminary Wind Speed Estimates around Greensburg, Kansas**	This is a detailed high resolution mean annual wind speed map developed by Wind Utility Consulting, PC. It is based in part on the Kansas Corporation wind speed map.



Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Preliminary Wind Speed Estimates around Greensburg, Kansas**	This is a detailed high resolution mean annual wind speed map developed by Wind Utility Consulting, PC. It is based in part on the Kansas Corporation wind speed map.

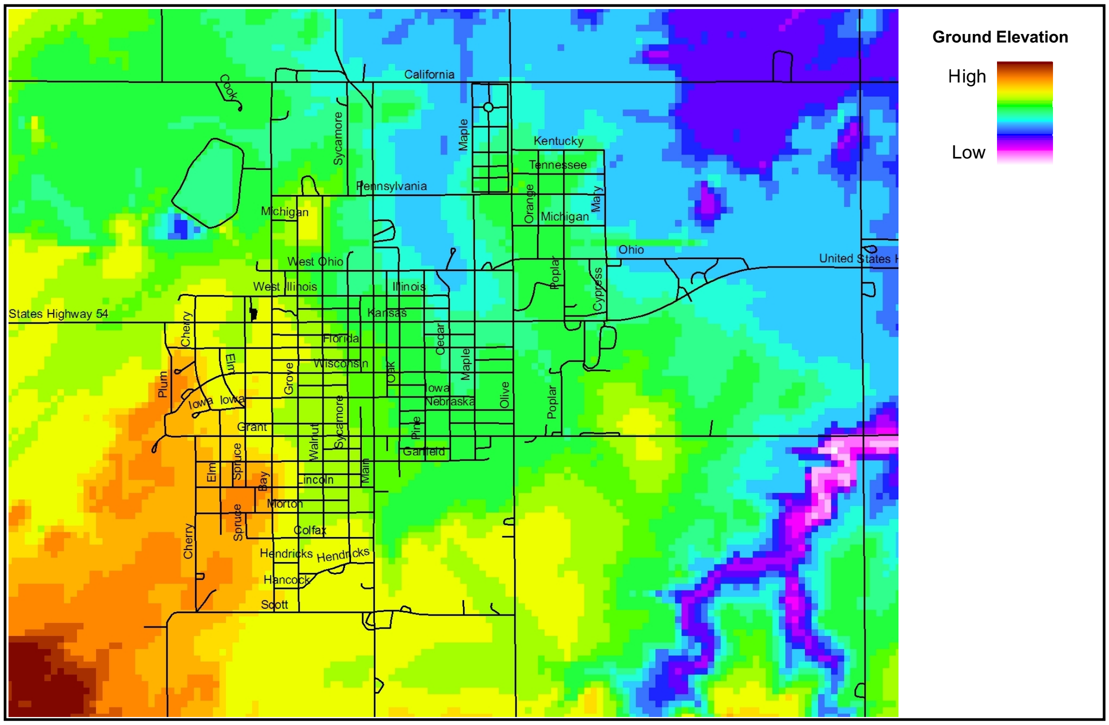


Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Preliminary Wind Speed Estimates around Greensburg, Kansas**	This is a detailed high resolution mean annual wind speed map developed by Wind Utility Consulting, PC. It is based in part on the Kansas Corporation wind speed map.

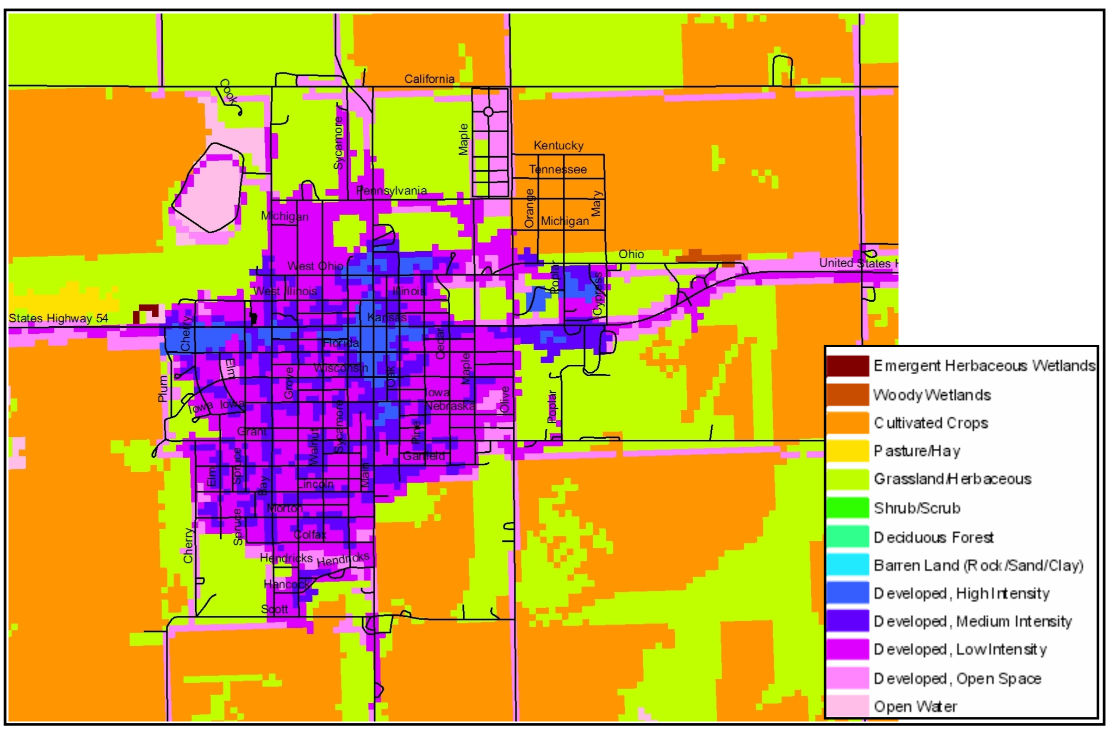


This wind rose directional data is from the closest meteorological test tower with publicly available data. It shows the predominant wind directions to be from the south and north.

Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Directional Wind Rose Applicable to Greensburg, Kansas Based on Deerfield, Kansas Data**	This wind rose is based on meteorological test tower data obtained from the Energy & Environmental Research Center (EERC) for the years of 1996-1998



Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Land Elevation around Greensburg, Kansas**	This map shows the ground elevation and is based on Digital Elevation Model data released by the United States Geological Survey.



Wind Utility Consulting, PC Jefferson, Iowa February 2008	**Land Use Data around Greensburg, Kansas**	This map shows the detailed land use types and is from the United States Geological Survey.

D.7 Recommendation: Only Very Small Wind Turbines Should be Building Mounted and Primarily for Architectural Purposes, not Primarily for Energy-generation Purposes

Jim Green

National Renewable Energy Laboratory

D.7.1 Specifications

- Building-mounted, or infrastructure-mounted, wind turbines in Greensburg should be 500 watts or less, and weigh 50 pounds or less.
- A rule of thumb in the wind industry is to install any turbine so the bottom of the rotor is 30 ft above any obstacle within a 500-ft radius.

D.7.2 Rationale

- Wind turbines mounted on buildings or infrastructure features such as light poles or communication towers can be a valuable visible statement architecturally.
- However, wind turbines have limited performance in electricity output, and can create unanticipated difficulties.

D.7.3 Advantages of building- or infrastructure-mounted wind turbines

- Using an existing or dual-use structure, part of a building or adjacent infrastructure, lowers wind turbine installation cost.
- Wind turbines visible on a building, or on site infrastructure immediately adjacent to the building, makes a strong statement of the building owner's commitment to renewable energy.

D.7.4 Disadvantages of building- or infrastructure-mounted wind turbines

- The vibration of the wind turbine can lead to acoustic noise inside the building.
- The vibration of the wind turbine can lead to structural vulnerabilities, especially for wood-frame construction.
- The weight of the wind turbine adds to the structural load on the building or structure, and must be considered in compliance with building codes.
- The building or structure itself will alter the wind pattern, introducing acceleration, turbulence, and/or flow separation. These effects will be specific to roof configuration, location on or above the roof, and local wind direction, making prediction of energy performance very difficult.
- Turbulent environments, such as adjacent to buildings, reduce both performance and life of wind turbines, adding to maintenance issues and reducing reliability.
- The very small-scale of wind turbines, as required to avoid other problems such as vibration, acoustics, and structural load, do not take advantage of economies of scale of larger wind turbines or wind turbine farms, raising the cost of energy.

D.8 Analysis of Photovoltaic Generation Options for Greensburg, Kansas

John P. Thornton, P.E.
Consultant
Littleton, Colorado
March 13, 2007

Lynn Billman
National Renewable Energy Laboratory

Executive Summary

There are many opportunities for the deployment of photovoltaic (PV) power systems to produce electricity for municipal, commercial and residential applications during the reconstruction of Greensburg, Kansas. The area has a good solar resource. There appear to be no major technical barriers; however, financial and institutional challenges exist.

The intention of this analysis is to provide a database of sufficiently accurate cost and performance data to be incorporated in strategic planning and used to attract financing, in finding state and federal incentives that may apply, and in educating stakeholders.

Most of the reconstruction effort is still in the discussion or conceptual design stage. Electrical loads were assumed in many cases, as were some basic building dimensions and the percentage of rooftop space available for PV. Information was gleaned from municipal planning documents and discussions with various stakeholders. It is important to remember that one of the major attributes of PV is its design flexibility. Each of the design options discussed in the report can be scaled down (or increased in size) to fit a budget.

The importance of the role of energy efficient buildings in the successful deployment of PV cannot be overstated. Implementing energy efficiency measures first will reduce the amount of PV needed by three or more times.

There are also excellent opportunities for the deployment of both active and passive solar space heating, as well as for solar hot water heating. Discussions of these options are not included in this report.

Numerous steps can be taken by the Greensburg City Council and staff, and organizations such as the Kiowa County Business Redevelopment Board to accelerate the pace of PV and other renewable projects. Some of these steps – such as city ordinances governing community and individual solar access and renewable interconnection requirements – are essential and should be given the highest priority. These steps are discussed in greater detail in Section 6, *A Suggested Implementation Strategy*.

Analysis, Discussion and Recommendations

1. Introduction

This report summarizes the results of investigations into the feasibility of incorporating PV electric power generation for municipal, commercial, industrial and residential applications during the reconstruction of Greensburg, Kansas. Greensburg, a municipality located in Kiowa County in the southwestern Kansas, was devastated by an EF5[1] hurricane on May 4, 2007. Approximately 95% of the buildings in the city were destroyed, with the remaining 5% being severely damaged. Tragically, 12 people were killed.

The investigations described in this report were performed as part of the support that the Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL) are providing to Greensburg.

2. The Solar Resource in Greensburg, Kansas

The area around Greensburg has a substantial solar resource. The solar resource map shown in Figure 1 indicates that the area around Greensburg receives an average of approximately 5.0 kilowatt hours (kWh) to 5.5 kWh per square meter (m^2) per day of insolation, or approximately 1,825 kWh to 2,008 kWh per m^2 annually.

The closest sites to Greensburg where a reliable database of solar resource data has been collected are Dodge City and Wichita, Kansas. These sites are both part of the National Solar Radiation Data Base (NSRDB), a repository of solar resource data that covers the years 1961 to the present.[2] Data for the city of Wichita, Kansas most closely represents the solar resource at Greensburg and so has been utilized as a surrogate in estimates of PV performance at Greensburg.

The suitability of Greensburg for solar deployment is shown in Table 1. The table provides a comparison of the insolation captured by a fixed-tilt, non-tracking PV array for selected NSRDB sites around the U.S. As can be seen, Greensburg receives approximately the average insolation for the continental United States and, therefore, has a sufficient solar resource for the efficient use of photovoltaic technologies.

3. PV Deployment in Greensburg

There are four basic PV system configurations that should be considered for deployment in Greensburg. These are: a. fixed-tilt, non-tracking, flat plate (Figure 2), b. single-axis tracking, flat-plate (Figure 3), c. two-axis tracking, flat-plate (also Figure 3), and d. concentrating (Figure 4). The potential of each configuration for Greensburg will be discussed below.

[1] EF5 describes the most powerful category of tornado. Tornados are rated on the Fujita scale from EF0 to EF5, where EF5 is the most severe.
[2] The NSRDB, which is maintained by NREL, is the nationally recognized source of solar radiation data for the United States. There are 239 stations in the U.S. and its territories. More information about the NSRDB may be obtained at http://www.nrel.gov and searching for "NSRDB."

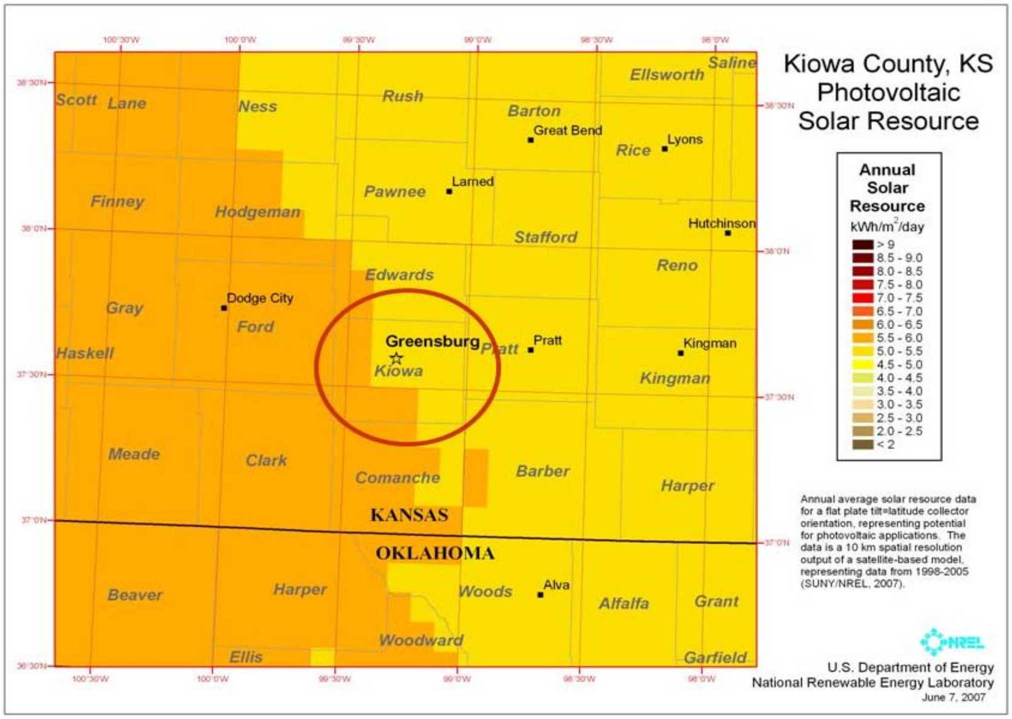


Figure 1. The solar resource available at Greensburg, Kansas[1]

Table 1. Comparison of Insolation Collected by a Fixed-Tilt, Non-Tracking, PV Array for Selected NSRDB Sites in the United States [2,3]

NSRDB Site	Average Solar Insolation ($kWh/m^2/day$)	Comparison with Wichita, KS
Colorado Springs, CO	5.6	1.08
Des Moines, IA	4.8	0.92
Dodge City, KS	5.6	1.08
Goodland, KS	5.6	1.08
Kansas City, MO	4.9	0.94
Omaha, NE	4.9	0.94
Sacramento, CA	5.5	1.06
San Diego, CA	5.7	1.10
Tucson, AZ	6.5	1.25
Tulsa, OK	5.1	0.98
Wichita, KS	5.2	1.00

3.1 Discussion of the Four PV Options

Table 2 provides a comparison of both the insolation-capturing abilities and the energy production potential of all four system configurations. The fixed-tilt, non-tracking, flat-plate configuration will collect up to 5.2 $kWh/m^2/day$ on average over a year. Because of their superior collection abilities, the one-axis and two-axis tracking configurations will collect 6.8 $kWh/m^2/day$ and 7.0 $kWh/m^2/day$ on average, respectively. A concentrating collector, because of its narrow field-of-view, will collect 3.7 $kWh/m^2/day$ to 4.8 $kWh/m^2/day$ on average.

For flat-plate configurations, PV systems will produce electricity proportional to the amount of energy collected. For a specific PV module, the tracking flat-plate configurations can be expected to produce about 28% to 36% more electricity annually than the fixed-tilt, non-tracking, flat-plate configuration.

The performance of concentrators cannot be directly compared to the flat-plate configurations. Although their narrow field-of-view collects less solar radiation, concentrators depend upon high PV cell efficiencies and a minimal use of expensive PV material to produce electricity on a cost-equivalent basis with the flat-plate configurations.

One of the main points to consider when selecting a PV configuration, other factors being equal, is the final cost of electricity (cents per kWh_{AC}).

The fixed-tilt, non-tracking, flat-plate system is the most frequently deployed configuration and is used for both ground- and roof-mounted applications. For each KW_{DC}[3] of rated capacity, a south-facing array will provide between 1,191 kWh_{AC} and 1,401 kWh_{AC} of electricity annually in Greensburg (Table 3).[4] Table 3 provides estimates, based on computer simulations, of the energy that will be produced by one KW_{DC} of rated capacity. The highest annual performance, i.e., the most kWh_{AC} of electricity, is achieved by a south-facing PV array tilted at an angle of 37.7 degrees, the latitude of Greensburg.

Table 3 also demonstrates how the orientation, or tilt, of a fixed-tilt, non-tracking, flat-plate PV array may be adjusted as needed to optimize performance during either winter or summer, or to accommodate pitched or flat roofs.

There are numerous opportunities for the deployment of PV in Greensburg. All of the identified possibilities are still in the discussion or conceptual stage. However, enough is known about these opportunities to provide preliminary estimates of cost and performance for planning purposes, to identify design approaches, to describe potential federal and state incentives, and to suggest a strategy for implementing some or all of these opportunities.

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[3] PV modules and arrays are rated in watts or kilowatts, respectively, and produce direct current electricity. Hence the module and array ratings are shown as W_{DC} or KW_{DC}, as measured under an internationally recognized system. These ratings are similar in nature to those on a car engine or power plant. One KW_{DC} of PV will provide different amounts of energy depending upon the intensity of the solar resource. The electricity produced by a PV array must be changed, or inverted, to alternating current (AC) electricity to be of use in a utility grid.

[4] The energy predictions in Table 3 are based upon computer simulations performed using PVWatts. PVWatts is a nationally recognized program that uses the NSRDB from 239 sites around the U.S. to predict the monthly and annual energy produced by a PV array based on the rated capacity of the array (KW_{DC}).

Figure 2. Typical fixed-tilt, non-tracking, flat-plate PV system (J. Thornton)

Figure 3. Typical one or two-axis tracking, flat-plate PV system (J. Thornton)

Figure 4. Typical utility-scale concentrating PV system (NREL PIX 13735)

Table 2. Comparison of Collection Abilities and Estimated Annual Electricity Production for Four Types of PV System Configurations at Greensburg, Kansas[1]

System Configuration	Insolation Collected ($kWh/m^2/day$)[1]	Relative Collection Ability	Estimated Annual Energy Production Per KW_{DC} (kWh_{AC})[3]
Fixed-Tilt, Non-Tracking, Flat-Plate[2]	5.2	1.0	1,401
1 Axis Tracking Flat Plate	6.8	1.28	1,796
1 Axis Tracking Flat Plate	7.0	1.36	1,900
Concentrator	3.7 – 4.8	N/A	N/A

[1] Derived from data for Wichita, Kansas (WBAN No. 03928) in the Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors, NREL/TP-463-5607, NREL, Golden, CO, April 1994.
[2] Tilted at an angle equivalent to the latitude for maximum annual electricity production.
[3] Estimates of annual energy production based upon PVWatts simulations.

Table 3. Simulated Monthly and Annual AC Energy Output (kWh) of a 1 Kilowatt-Rated, South-Facing, Fixed-Tilt, Non-Tracking PV Array in Greensburg, KS [1,2]

Month	Tilt Angle From Horizontal (degrees)						
	0	10	20	30	37.7 Latitude	45	60
January	58	75	89	100	106	111	115
February	71	84	95	103	107	109	110
March	100	109	116	120	121	120	114
April	121	127	130	130	127	123	110
May	135	137	136	132	127	120	101
June	140	140	136	130	124	116	94
July	143	143	141	136	130	122	100
August	132	137	138	136	133	128	111
September	101	109	115	117	117	116	108
October	84	98	109	116	120	122	120
November	58	72	84	93	98	102	105
December	47	62	75	84	90	94	98
Annual	1191	1284	1364	1398	1401	1384	1286

[1] Based upon PVWatts simulations using Wichita, KS, NSRDB data as a surrogate insolation profile for Greensburg, KS. These values may vary by ±9% for specific months and/or years.
[2] To estimate the monthly or annual energy output of a PV array, multiply the rated capacity of the array in KW_{DC} by the monthly or annual output in the chart above for the desired tilt angle. For example, the estimated output of a 5 KW_{DC} array tilted at 37.7 degrees during July will be 5 x 139 or 695 kWh.

3.2 Solar Electric Opportunities in Greensburg

Several upcoming projects will provide opportunities to incorporate PV technologies into the city of Greensburg's infrastructure. Incentives may apply to some of these opportunities. See Section 5 and the Addendum for further details.

The costs used below are broad estimates based upon the 2007 nationwide market for PV. They include estimates of maintenance over an expected lifetime of 25 years. These estimated costs should be used for planning only. Firmer cost estimates will become possible as designs mature.

3.2.1 Courthouse (221 E. Florida)

The courthouse is one of the few buildings that survived the tornado, although not without significant damage. If repaired, the building appears to be suitable for mounting PV on the roof, although this would have to be confirmed by an inspection and a structural analysis. The roof has an estimated area of 8,000 ft.^{2}. Although it was not examined because of safety concerns, an area of 6,000 ft.^{2} is assumed to be usable, with the rest of the space being occupied by vents, air conditioners, etc.

Depending on the choice of PV module selected and the method of mounting, an estimated 48.7 KW_{DC} to 97.9 KW_{DC} of PV capacity could be mounted in 6,000 ft.^{2}, generating from 63,018 kWh_{AC} to116,599 kWh_{AC} of electricity per year. The installed system cost will range from about $636,000 to $735,000. The electrical requirements of the courthouse after renovation has not been estimated yet, so it is not possible to project what percentage of the building's annual load could be supplied by PV. The resulting cost of energy from the PV system is estimated at 25 cents per kWh_{AC} (¢/kWh_{AC}) to 30 ¢/kWh_{AC}. The system would be connected to the utility grid.

3.2.2 The School

The school is expected to have an estimated flat roof area of 80,000 ft^2. The annual electrical load is expected to be 1,500,000 kWh_{AC}. An area of 60,000 ft^2 was assumed as useable space for PV. The school is assumed to be grid-connected with no electrical storage capability.

3.2.2.1 Roof-Mounted Options

Two roof-mounted configurations using fixed-tilt, non-tracking, flat-plate arrays have been examined. The first configuration assumes that modules will be mounted flat on the roof's surface. Depending on the choice of PV module selected and the method of mounting, an estimated 747.3 KW_{DC} to 979.0 KW_{DC} of PV capacity could be mounted in 60,000 ft.^{2}, generating about 890,034 kWh_{AC} to 1,165,989 kWh_{AC} of electricity per year. The installed system cost will range from about $3,736,500 to $4,895,000. It will displace between 59% and 78% of the electrical energy consumed by the school annually at an estimated lifecycle cost, including maintenance, of 18 ¢/kWh_{AC}. Of the two roof configurations investigated, the flat-mounted option permits the highest capacity PV array to be installed on the roof with the most energy produced annually.

Possible drawbacks to a flat-mounted system include material incompatibility between the underside of the PV module and the roofing material and the collection of moisture leading to mold or fungal growth. These issues should be thoroughly discussed with manufacturers and installers as well as the supplier of the roofing material.

The second roof-mounted configuration tilts the modules to the south at an angle of 10º. Spacing will be required between rows to minimize shadowing of modules, which will reduce the rated capacity (KW_{DC}) of the PV array that can be installed. The slight tilt from 0º to 10º does increase the annual performance slightly from 1,191 kWh_{AC} per KW_{DC} to 1,284 kWh_{AC} per KW_{DC}, an improvement of nearly 8%.

Tilting fixed-tilt, non-tracking, flat-plate PV modules toward the south up to an angle equivalent to the latitude of the location does improve performance (Table 3). At a tilt equivalent to the latitude of Greensburg (37.7º), the estimated annual output is 1,401 kWh_{AC} per KW_{DC} of installed capacity, an improvement of nearly 18%. However, spacing between rows becomes much greater with a substantially reduced array capacity being possible.

Module tilts of 10º are commonly used on flat-roofed buildings to obtain improved performance over a flat array, while keeping wind loading to reasonable levels. An array with a 10º tilt will usually be less than parapet height. The structure can also be designed to allow air circulation that keeps moisture accumulation to a minimum. As a result, material incompatibility problems tend to be reduced.

Depending on the choice of PV module selected and the method of mounting, an estimated 487.2 KW_{DC} to 645.0 KW_{DC} of PV capacity could be mounted in 60,000 $ft.^2$, generating about 630,437 kWh_{AC} to 834,630 kWh_{AC} of electricity per year. The installed system cost will range from about $3,736,500 to $4,895,000. It will displace between 42% and 55% of the electrical energy consumed by the school annually at an estimated lifecycle cost, including maintenance, of 16 ¢/kWh_{AC}.

3.2.2.2 Alternative Options

Alternative options include generating some or all of the 1,500,000 kWh_{AC} annual load using a field of ground-mounted, one or two-axis tracking or concentrator arrays located in a nearby field (Figures 3 and 4). A one-axis tracking system rated at approximately 835 KW_{DC} could supply the full annual electrical load of the school. The installed system cost would be approximately $4,592,500, with electricity costing about 0.13 ¢/kWh_{AC} over the expected 25-year lifetime of the system. The system would occupy about 2 acres to 2.5 acres of land.

Similarly, a two-axis tracking system rated at approximately 793 KW_{DC} could supply the full annual electrical load of the school.

3.2.3 Other Municipal Buildings

The courthouse and school PV system concepts described above in Sections 3.2.1 and 3.2.2 represent typical PV systems on small and large buildings, respectively, in a small municipality.

Other potential projects for roof-mounted PV, such as the Business Incubator or a hospital, should have similar costs and performance. PV system costs and performance for other projects can be estimated as soon as preliminary designs become available that provide the dimensions, orientation and pitch of available roof space.

In addition to mounting on flat or pitched roofs, or in open fields, PV awnings can be used as shades, facades, and other architectural features (Figures 5 and 6).

3.2.4 Municipal Utility Applications

To be effective, a grid-connected PV system does not have to be located on or next to its point of application to be effective. It can be sited in any open area, although proximity to an existing distribution point serves to keep the overall installation costs to a minimum. Any electricity generated by the PV system can be used by the grid while the utility reduces the use of traditional sources of energy, such as diesel generators or combustion turbines.

Figure 5. PV modules being used as awnings to provide shade as well as electric power

Figure 6. PV modules being used as an overhead shade on a commercial building

Any of the four system configurations will provide the required electricity, although significant economic advantages will probably be realized by using a one or two-axis tracking or a tracking concentrator system. A utility-scale PV system with a capacity of 1,000 KW_{DC} or greater would probably cost about $5,000 per KW_{DC} installed. During its lifetime of 25 years, the system could be expected to produce electricity for about 13¢/ kWh_{AC}.

A system that supplied Greensburg's annual energy load would be quite large. Greensburg's estimated 2008 annual electricity requirement has been estimated to be 6.6 million kWh_{AC}[2]. A one-axis tracking PV system rated at 3,675 KW_{DC} and covering about 10 acres would be required to generate that amount of electricity. The installation cost would probably be $18 million to 19 million.

3.2.5 PV Lighting Opportunities

PV lighting can be both cost-effective and affordable, especially when combined with modern, super-bright LED lamps. Solar-generated electricity is used to charge batteries during daylight hours, with the energy used to power the lights at night. There are many possible sites for small, self-contained, stand-alone PV signs in and around Greensburg, including the courthouse lawn, the highway approaches and city parks. Lighting projects are usually modest in size and can be implemented quickly.

There are many PV lighting systems available off-the-shelf that are applicable to nearly every lighting application. Ordering a pre-built system complete with warranties and adapting it to a special need is usually the most cost-effective way of obtaining PV lighting. It is also possible to assemble custom-made systems for unique applications.

Larger projects, such as sports fields that require intense, color-balanced lighting are best supplied directly from the grid. PV can be used to contribute to the load by generating energy during the day that is used to offset the electrical use at night.

3.2.5 PV-Powered Streetlamps

Several PV-powered streetlights are currently available. Various models use both high- and low-pressure sodium, incandescent, compact fluorescent and LED luminaries. All operate by charging self-contained batteries during daylight hours and using the stored energy to light the lamps during nighttime or on dark days. Luminosity ranges from about 1,800 lumens to 5,800 lumens. Each type of light has unique features as well as disadvantages.

High-pressure sodium and fluorescent lamps provide good color-balance. Yet both use ballasts, which require energy from the batteries. In addition, the ballasts of fluorescent lamps are affected by temperature, and on cold nights these lights may lose a substantial amount of illumination.

Low-pressure sodium lamps provide reliable service and are not significantly affected by temperature. However, the orange cast to the light distorts colors and is not generally pleasing to passersby.

Several manufactures have incorporated super bright, white LEDs into streetlights. These streetlights feature low-energy-consuming lamps that provide a luminance of 1,800 lumens or greater, have near-normal color balance and have rated lifetimes of 40,000 hours to 50,000 hours. LEDs significantly reduce the amount of PV and batteries needed to provide power. In addition, they contain no mercury, and are considered environmentally friendly. For these reasons, LED lamps are recommended for either solar- or non-solar-powered streetlights.

PV-powered streetlights are available as complete units including the solar panels, batteries and control electronics. Because of this extra equipment, they are more expensive as compared to conventional streetlights that are connected to the grid. PV streetlights can be purchased for approximately $3,000 to $4,600 each.

When comparing the cost of PV streetlights against traditional grid-powered models, many factors must be taken into consideration, including the relative costs of installation, digging up streets to connect to the grid.

3.3 Privately Funded Opportunities

There are numerous opportunities to incorporate energy efficiency and PV in the rebuilding of commercial, residential and farm properties as well.

3.3.1 General Motors Dealership

One of the first structures to be rebuilt will be the General Motors (GM) dealership. The building will have a 100 ft. by 70 ft. floor area. The roof will face east-west with a pitch of 1/12, giving it a minimum area of approximately 7,014 ft^2. The roof construction will likely be screw-down metal rather than standing-seam for cost consideration. The screw-down metal roof will allow a higher packing density for PV modules.

Energy production from the roof will still be substantial in spite of the east-west orientation. Computer simulations indicate that the annual energy output from the roof will be about 1,191 kWh_{AC} or 97% of that produced by a south-facing PV array.

The GM dealer is currently negotiating with Energy Conversion Devices for the installation and possible donation of Uni-Solar roofing laminates. While a system configuration is not available at this time, a 7,014 ft^2 roof would support an estimated 38.4 KW_{DC}, or possibly even greater. A PV system capacity of 38.4 KW_{DC} will generate an estimated 45,734 kWh_{AC} per year. The building's projected annual energy requirements are not known at this time.

3.3.2 Other Commercial Building Opportunities

Other opportunities exist for incorporating PV during reconstruction, including on the John Deere dealership and Kwik Stop gas station and convenience store. These buildings can expect similar performance and costs as the public buildings described earlier.

The Kwik Stop could utilize a PV canopy, a unique feature that is being adopted by stations worldwide (Figure 7). The canopy generates electric power while allowing a reduced level of sunlight to penetrate to the pump level. The PV modules in the canopy are grid-connected, and since they have no backup storage systems, will operate only during daylight hours when

Figure 7. PV canopies are often used to shade gasoline pumps at service stations. (NREL PIX 11979)

the grid is operational. Their primary purpose is to trim high daytime loads, such as those from air conditioning. The canopies are very visual and attract a lot of attention from customers. The translucent modules are available from BP Solar.

3.3.3 <u>Grid-Connected Residential Opportunities</u>

Grid-connected PV systems are often used on residential structures to provide energy to offset the local utility. They are often used to net meter or "trade" electricity with the local utility. When an excess of PV-generated energy over and above what is needed to operate the residence is available, the excess is fed *into* the grid, giving the homeowner a credit. When the PV system cannot supply sufficient energy, extra energy is drawn *from* the grid to make up the deficit. At some interval, usually annually, the homeowner's account is balanced by the utility. The utility will provide credit, or sometimes pay, for the surplus provided by the homeowner. Similarly, the homeowner will pay for any electricity provided by the utility.

Residential PV systems usually range from two KW_{DC} to four KW_{DC} in size, and on homes in Greensburg will supply from 1,191 kWh_{AC} to 1,401 kWh_{AC} per installed KW_{DC} annually, depending upon the roof orientation, pitch and tilt of the array. The cost of a fully installed two to four KW_{DC} grid-connected system will typically range from $16,000 to $32,000, not including incentives, which is equivalent to an electricity charge of 30¢/ kWh_{AC} to 35¢/ kWh_{AC}.

3.3.4 Grid-Independent (Stand-Alone) Residential Opportunities

PV systems for grid-independent residences are larger because of the need to keep batteries charged in addition to operating the home without assistance from the grid. These systems will typically be rated from three KW_{DC} to six KW_{DC}. They will supply from 1,191 to 1,401 kWh_{AC} per installed KW_{DC} annually, depending upon the roof orientation, pitch and tilt of the array. They are more expensive because of the cost of the inverter capable of independent operation and the batteries needed for storage of the electricity, costing from $12,000 to $15,000 per installed KW_{DC}, not including incentives.

3.3.5 Farm and Agricultural Opportunities

Typically rural parts of America have many needs for power to control irrigation, pump water, run workshops, provide heat and cooling, maintain communications and ensure financial operations (Figures 8 and 9). PV can supply the electricity needed for many of these applications. Federal grants and loans from the United States Department of Agriculture are available. See Section 5 for further details.

4. PV Design Considerations

PV is a mature technology with a demonstrated history of supplying reliable and cost-effective power for many applications. The design considerations described below will help ensure that PV is applied in the most effective ways for Greensburg.

4.1 Flexibility of PV

One of the main advantages of PV is its modularity. A system capable of supplying the full energy need for an application may be desirable, but may not be absolutely necessary if tight budgets are a consideration. Grid-connected PV systems can be designed to shave peak loads or supply power at critical times, while relying on the utility to provide the balance of electricity when needed. PV systems can be tailored in size to meet a budget.

Figure 8. A PV-powered electric fence charger (NREL PIX 04347)

Figure 9. A PV-powered irrigation controller (Shell Solar, NREL PIX 03352)

4.2 The Importance of Energy Efficiency in PV System Design

Conducting energy efficiency measures first in a building will reduce the amount of PV needed by three or more times.

4.3 Grid-Connected Versus Grid-Independent Operation

Grid-connected PV systems have the lowest capital and maintenance costs. However, their operation is controlled by the local grid for safety reasons. If the utility grid loses power, the inverter that controls the PV system will sense the fault and automatically shut down the PV system. Most grid-connected systems do not have storage and, therefore, cannot be relied upon to provide emergency power during blackouts.

In the United States, the most cost-effective grid-connected systems are usually designed to generate the equivalent amount of electricity that a building will use in a year. Excess energy purchased from a customer by a utility will be at the utility's avoided cost. The avoided cost is substantially less than the retail price of electricity, plus taxes, that is paid by the consumer to the utility for electricity.

Stand-alone or grid-independent PV systems incorporate storage. Energy is collected by the PV system during daylight hours and stored in batteries for use at night or during cloudy weather. Two to three days of storage are usually sufficient for a typical residence. High-value applications, such as telecommunications, uninterruptible power supply (UPS), or security systems, often have even greater storage capacity.

Stand-alone systems require more PV modules than a grid-connected PV system because of the need to supply daily electricity while also keeping the batteries charged. These systems are more expensive than grid-tied systems, often costing twice as much, or more. An advantage of these systems is that once they are purchased, the price of electricity is fixed.

A stand-alone or grid-independent PV system should be located near its point of application for reliability. Overhead power lines are vulnerable during wind and hail storms. There are many cases on record where the loss of power lines during a disaster has disabled a PV system, even though the PV system remains operational. If a grid-independent PV system must be remotely located, the use of underground power lines is strongly suggested.

Systems that are both grid-connected and capable of independent operation can also be procured. When the utility grid fails, the PV system disconnects from the grid and switches over to independent operation, relying on electricity stored in batteries (Figure 10).

Figure 10. A PV UPS system at NREL that supplies electricity to XCEL Energy during normal operation and emergency power to the laboratory during power interruptions (J. Thornton).

4.4 <u>PV/Wind Hybrid Operation</u>

PV is synergistic with other technologies, such as wind, and can be used in hybrid systems. The wind resource is often available when the sun is not, and visa versa. The availability of both the wind and solar resources is often seasonal in the mid-western U.S. Wind/solar hybrid systems are used throughout the Midwestern states (Figure 11).

Hybrid wind and solar systems can usually be installed in rural areas without a problem. In more densely populated areas, such as Greensburg, noise ordinances and tower height restrictions may limit their use.

5. <u>PV-Related Incentives Available to Greensburg</u>

Table 4 shows the incentives that are available to the City of Greensburg, its businesses and residents. Table 5 and the addendum describe these incentives in greater detail. Of particular note is the Renewable Energy Production Incentive (REPI), which provides financial incentive payments for electricity produced and sold by new qualifying renewable energy-generation facilities. Qualifying facilities are eligible for annual incentive payments of 1.5¢ per kilowatt-hour (in 1993 dollars and indexed for inflation) for the first ten-year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation. Originally designed to terminate in 2003, the Energy Policy Act of 2005 reauthorized appropriations for fiscal years 2006 through 2026.

Figure 11. A wind farm maintenance shop in Woodstock, Minnesota that uses a hybrid wind and PV system as a source of power

6. A Suggested Implementation Strategy

Most potential PV applications for Greensburg are still in the discussion stage and can best be approached using generalized estimates. A few applications, such as the Business Incubator, the school and the General Motors dealer, have been sufficiently defined to the point where preliminary estimates of performance and price can be established.

Even at this early stage, there are numerous steps that can be taken by the Greensburg City Council and staff, and organizations such as the Kiowa County Business Redevelopment Board to accelerate the pace of PV and other renewable projects. Some of these steps, e.g., city codes governing community and individual solar access and renewable interconnection standards, are essential and should be given the highest priority.

Table 4. Solar-Related Incentives Available From the Federal Government and State of Kansas[1,2]

Incentive	Type	Entity			
		Municipal Government	Municipal Utility/REC	Commercial/ Industrial/ Agricultural	Residential
USDA Grant Program	Federal			X	
USDA Loan Program	Federal			X	
Solar Tax Credit	Federal			X	X
Accelerated Depreciation	Federal			X	
R/E Production Incentive	Federal	X	X		
Property Tax Exemption	State			X	X

[1] Excerpted from the DSIRE database; http://www.dsireusa.org.
[2] Incentives may also apply to other renewable technologies, such as wind. Please refer to the Addendum for more detail.

Table 5. Financial Incentives for Energy Efficiency and Renewable Energy[1,2]

Incentive	Type/Name	Amount / Maximum / Notes	Timing
1	Federal Grant Program (USDA 9006)	25% of eligible project costs (grants and guaranteed loans together, see below, cannot exceed 50% of eligible project costs). Maximum grant for renewable energy projects is $500,000; maximum grant for energy efficiency improvements is $250,000. http://www.rurdev.usda.gov/rbs/farmbill	Annual application process and competition. FY2007 awards averaged $53,000 per project in grants and/or loans. Another application process for FY2008 is hopeful.
2	Federal Guaranteed Loan Program (USDA 9006)	Up to 50% of eligible project costs (grants and guaranteed loans together, see above, cannot exceed 50% of eligible project costs). Maximum loan guarantee is $10M. http://www.rurdev.usda.gov/rbs/farmbill	Annual application process and competition. FY2007 awards averaged $53,000 per project in grants and/or loans. Another application process for FY2008 is hopeful.
3	Federal Tax Credit - Commercial Solar	30% of the total costs of solar systems (photovoltaic electricity and hot water), solar hybrid lighting, and fuel cells, and 10% for geothermal electric, direct use geothermal, and microturbines. Excludes geothermal heat pumps. Other restrictions and requirements apply. http://www.irs.gov/pub/irs-pdf/f3468.pdf	Valid on systems installed before December 31, 2008.
4	Federal Tax Credit – Residential Solar	30% of the total costs of solar systems (photovoltaic electricity and hot water), solar hybrid lighting, and fuel cells, and 10% for geothermal electric, direct use geothermal, and microturbines up to a maximum of $2,000. Excludes geothermal heat pumps. Other restrictions and requirements apply. http://www.irs.gov/pub/irs-pdf/f3468.pdf	Valid on systems installed before December 31, 2008

(Continued on next page)

Table 4. (continued) Financial Incentives for Energy Efficiency and Renewable Energy[1,2]

Incentive	Type/Name	Amount / Maximum / Notes	Comments
5	Federal Corporate Depreciation (Modified Accelerated Cost-Recovery System	Corporate and industrial solar investments can be depreciated in five years. http://www.dsireusa.org See Federal incentives section.	Annual application process and competition. FY2007 awards averaged $53,000 per project in grants and/or loans. Another application process for FY2008 is hopeful.
6	Renewable Energy Production Incentive	Provides 1.5¢/kWh incentive payments for electricity produced and sold for first 10 years by qualified renewable energy generation facilities	Open to municipal utilities, rural electric cooperatives and state/local governments that sell electricity
7	Kansas State Property Tax Exemption	100% of investment is exempted from property taxes in Kansas. Does not apply to solar hot water. Kansas Statute KSA 79-102(11). http://www.dsireusa.org	Applies to residential, commercial and industrial properties

[1] Excerpted from the DSIRE database; http://www.dsireusa.org.
[2] Some of these incentives may apply to other renewable technologies, such as wind. Please refer to the Addendum for more details.

6.1 Municipal Government

Steps that may be taken by the municipal government include the following:

- Develop a city statement-of-purpose that promotes a standard for community reconstruction. Such a statement could suggest that municipal buildings should at least be built to a LEED standard, with encouragement to build to a higher standard, such as the American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) that achieve 30% energy savings, or even a zero-energy building. The statement-of-purpose should also encourage commercial building owners and homeowners to build to equivalent codes and standards.
- Establish city codes governing community and individual solar access.[5]
- Implement a renewable interconnection plan that considers both PV and wind.
- Encourage the use of solar hot water systems for municipal, commercial, and residential projects.
- Rate municipal projects, e.g. the Courthouse, school and business incubator,

[5] Solar access is the availability of (or access to) unobstructed, direct sunlight. For more information and resources, see www.eere.energy.gov/consumer/renewable_energy/solar.

according to priority and the potential for incorporating energy efficiency and renewable technologies, including PV. Focus on short-term efforts to develop the one or two (depending upon available budget and other resources) highest priority projects as examples that can be followed by others.

- Establish municipal guidelines for citizens. Produce a *Greensburg Citizens' Guide to Renewable Energy* that includes these guidelines and outlines a process for initiating and completing a renewable energy project. The guide could include information specifically relating to municipal codes and ordinances. It could be distributed free-of-charge to all citizens. There are many renewable consumer guidelines available that could be used as examples.
- Spearhead a community education program that would conduct workshops to educate city workers, business owners and residents on how to implement an energy efficiency or renewable energy project and to provide realistic expectations as to the use of these technologies. Use nationally recognized experts to provide impartial information to consumers.
- Implement a priority building permitting process that would give priority to energy-efficient and renewable-powered projects. Time is money to most builders and developers, and an enhanced permitting process may provide the incentive to "go green." These types of programs have worked well in California.
- In conjunction with economic development groups, e.g. the Kiowa County Business Redevelopment Board, and service groups, e.g. Rotary Club, develop a process to attract potential sponsors to fund both municipal and private renewable projects.
- Encourage the Governor and Kansas State Legislature to pass bills that establish a state Renewable Energy Standard (RPS) providing incentives for the use of PV and other renewables.

6.2 <u>Community Organizations</u>

Community organizations have a very significant role to play in the reconstruction of Greensburg as a "green" community. There are at numerous major areas where they can have a substantial impact, including, but not limited to:

- Support one of the privately-funded commercial renewable-energy projects in Greensburg to ensure the project becomes an exemplary model for others to follow.
- Support the municipal government in its efforts to establish codes and ordinances for renewable use.
- Collaborate with municipal government to provide citizen workshops and other educational programs, including providing space and partial funding to conduct these workshops.
- Help to attract national sponsors to help finance renewable projects.
- Support municipal leaders' efforts to promote legislative bills that establish a state RPS that will provide incentives for the use of PV and other renewables.

7.0 <u>Useful Websites</u>

The following websites will be informative to homeowners, business owners and city staff interested in using PV and energy efficiency.

Glossary of Energy Terms
This section of the DOE Web site (Solar Glossary of Terms) contains helpful definitions of common and rarely used energy-related terms.
http://www1.eere.energy.gov/solar/solar_glossary.html

Photovoltaic Basics
Have you ever wondered how electricity is produced by a photovoltaic — what we often call a PV or solar electric — system? We'll help you understand by covering the basics of PV technology, which includes the underlying physics, how various PV devices are designed and become fully functional systems, and what's happening today in PV research and development.
www1.eere.energy.gov/solar/pv_basics.html

Home Power Magazine
This bimonthly magazine is full of articles and ideas for the do-it-yourselfer and contains advertisements from suppliers nationwide. www.homepower.com

National Renewable Energy Laboratory
What is renewable energy? Why is it important? And why is energy efficiency important? Visit this site for answers to these questions. You'll also find specific information for the homeowner, business owner, and farmer or rancher. http://www.nrel.gov/learning/using_re.html

Database of State Incentives for Renewable Energy (DSIRE)
This comprehensive source provides information on state, local, utility, and selected federal incentives that promote renewable energy. www.dsireusa.org

How to Build a Better Home
Learn to use solar energy and the whole-building approach to reduce your environmental impact, live comfortably, and save money. www.nrel.gov/docs/fy00osti/26582.pdf

Energy-Efficient Water Heating
Water heating constitutes 14% of the total energy consumption of residential buildings. Learn how to reduce that energy expenditure by using efficient practices.
http://www1.eere.energy.gov/solar/sh_basics_water.html

Solar Hot Water and Space Heating and Cooling
Do you have trouble telling the difference between a thermosiphon and a draindown system? Don't give it another thought. Visit this Web site and you'll soon see that these technologies are relatively easy to understand. Solar water heating is among the most practical, affordable, and durable renewable energy technologies available.
http://www.eere.energy.gov/consumer/your_home/water_heating/index.cfm/mytopic=12850

Photovoltaics
Here's an excellent introduction to solar electricity. You'll see simple diagrams of how solar cells operate and how they are joined together to form modules and arrays. There's also a batch

of Frequently Asked Questions, which just may answer some of yours.
www.flasolar.com/photovol_main.htm

A Consumer's Guide to Buying a Solar Electric System
This booklet is designed to guide you through the process of buying a solar electric system. A solar electric system can be a substantial investment — but careful planning will help ensure that you make the right decisions. www.nrel.gov/docs/fy99osti/26591.pdf

Making the Most of Residential Photovoltaic Systems
Read this booklet to see how far you can stretch solar energy by adding energy efficiency features to your home. www.nrel.gov/docs/fy99osti/26373.pdf

Build It Solar
This site is for everyone who is interested in solar energy: what it is, whether you need it, and how and where you get it. www.builditsolar.com/Projects/PV/pv.htm

8.0 References

1. Renewable Resource Availability in Greensburg, National Renewable Energy Laboratory, Golden, CO, June 8, 2007.

2. National Solar Radiation Data Base 1961-1990, National Renewable Energy Laboratory, Golden, CO, 1992.

3. National Solar Radiation Data Base 1991-2005 Update, National Renewable Energy Laboratory, Golden, CO, June 8, 2007.

4. Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors, NREL/TP-463-5607, NREL, Golden, CO, April 1994.

Addendum
Federal and State Incentives for Solar Systems

Excerpted from the Database of State Incentives for Renewables and Efficiency (DSIRE)
(http://www.dsireusa.org)

USDA Renewable Energy Systems and Energy Efficiency Improvements Program

Incentive Type:	Federal Grant Program
Eligible Efficiency Technologies:	Yes; specific technologies not identified
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Biomass, Geothermal Electric, Geothermal Heat Pumps, Hydrogen, Direct-Use Geothermal, Anaerobic Digestion, Renewable Fuels, Fuel Cells using Renewable Fuels
Applicable Sectors:	Commercial, Agricultural
Amount:	Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs
Max. Limit:	Grants: $500,000 per renewable-energy project; Guaranteed loans: $10 million
Authority 1:	Farm Security And Rural Investment Act of 2002 (Sec. 9006)
Date Enacted:	5/13/2002
Effective Date:	FY 2003
Expiration Date:	FY 2007
Authority 2:	Renewable Energy Systems and Energy Efficiency Improvements Program (Final Rule: 7 CFR 42480)
Effective Date:	7/18/2005
Website:	http://www.rurdev.usda.gov/rbs/farmbill/

Summary:

Note: The deadlines for Grant Applications and Guaranteed Loan and Combined Guaranteed Loan and Grant Applications for FY 2007 have passed. This program is up for reauthorization in the 2007 Farm Bill.

Section 9006 of the 2002 Farm Bill required the U.S. Department of Agriculture (USDA) to create a program to make direct loans, loan guarantees, and grants to agricultural producers and rural small businesses to purchase renewable-energy systems and make energy-efficiency improvements. Funding in the amount of $23 million per year was appropriated for FY 2003 through FY 2007. This program is known as the *Renewable Energy Systems and Energy Efficiency Improvements Program.*

The maximum ***grant*** award is 25% of eligible project costs up to $500,000 for renewable energy projects and up to $250,000 for energy efficiency improvements. Assistance to one individual or entity is not to exceed $750,000. The minimum grant request is $2,500 for renewable energy projects and $1,500 for efficiency projects. Eligible renewable energy projects include wind, solar, biomass and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. Applications must be submitted to the appropriate Rural Development State Office.

Under the ***guaranteed loan*** option, funds up to 50% of eligible project costs (with a maximum project cost of $10 million) are available. The minimum amount of a guaranteed loan made to a borrower is $5,000. A combined grant and guaranteed loan under this program cannot exceed 50% of eligible project costs, and the applicant or borrower is responsible for having other funding sources for the remaining funds. The maximum percentage of guarantee ranges from 70% to 85% depending on the loan value; the percentage for a given project will be negotiated between the lender and the Rural Business-Cooperative Service. The interest rate will be negotiated between the lender and the applicant and the repayment term must not exceed 30 years for real estate, 20 years for machinery and equipment, and seven years for working capital.

The USDA has implemented this program through a Notice of Funds Availability (NOFA) for each of the last five years. The fifth round of funding was made available in March 2007 in the form of grants, guaranteed loans, and combined guaranteed loans and grant applications. Grant Applications were due May 18, 2007. Guaranteed Loans and Combined Guaranteed Loans and Grants Applications were July 2, 2007.

USDA announced in September 2007 that 345 proposals in 37 states were selected to receive a total of $18.2 million for renewable energy and energy efficiency projects as a result of the FY 2007 solicitation. Of the $18.2 million total, $13.4 million are grants and $4.8 million are guaranteed loans.

USDA Renewable Energy Systems and Energy Efficiency Improvements Program

Incentive Type:	Federal Loan Program
Eligible Efficiency Technologies:	Yes; specific technologies not identified
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Biomass, Geothermal Electric, Geothermal Heat Pumps, Hydrogen, Direct-Use Geothermal, Anaerobic Digestion, Renewable Fuels, Fuel Cells using Renewable Fuels
Applicable Sectors:	Commercial, Agricultural
Amount:	Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs
Max. Limit:	Grants: $500,000 per renewable-energy project; Guaranteed loans: $10 million
Authority 1:	Farm Security And Rural Investment Act of 2002 (Sec. 9006)
Date Enacted:	5/13/2002
Effective Date:	2003
Expiration Date:	FY 2007
Authority 2:	Renewable Energy Systems and Energy Efficiency Improvements Program (Final Rule: 7 CFR 42480)
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Website:	http://www.rurdev.usda.gov/rbs/farmbill/

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USDA announced in September 2007 that 345 proposals in 37 states were selected to receive a total of $18.2 million for renewable energy and energy efficiency projects as a result of the FY 2007 solicitation. Of the $18.2 million total, $13.4 million are grants and $4.8 million are guaranteed loans.

Business Energy Tax Credit

Incentive Type: Corporate Tax Credit

Eligible Renewable/Other Technologies: Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Geothermal Electric, Fuel Cells, Solar Hybrid Lighting, Direct Use Geothermal, Microturbines

Applicable Sectors: Commercial, Industrial

Amount: For equipment placed in service from January 1, 2006 until December 31, 2008, the credit is 30% for solar, solar hybrid lighting, and fuel cells, and 10% for microturbines. The geothermal credit remains at 10%.

Maximum Incentive: $500 per 0.5 kW for fuel cells; $200 per kW for microturbines; no maximum specified for other technologies

Eligible System Size: Microturbines less than 2 MW; fuel cells at least 0.5 kW

Authority 1: 26 USC § 48

Authority 2: IRS Form 3468 (Tax Year 2006)

Summary:

The federal Energy Policy Act of 2005 (H.R. 6) expanded the federal business energy tax credit for solar and geothermal energy property to include fuel cells and microturbines installed in 2006 and 2007, and to hybrid solar lighting systems installed on or after January 1, 2006. These provisions of the tax credit were later extended through December 31, 2008, by Section 207 of the Tax Relief and Health Care Act of 2006 (H.R. 6111). (A 10% federal energy tax credit was available to businesses that invested in or purchased solar or geothermal energy property in the United States prior to January 1, 2006.)

For eligible equipment installed from January 1, 2006, through December 31, 2008, the credit is set at 30% of expenditures for solar technologies, fuel cells and solar hybrid lighting; microturbines are eligible for a 10% credit during this two-year period. For equipment installed on or after January 1, 2009, the tax credit for solar energy property and solar hybrid lighting reverts to 10% and expires for fuel cells and microturbines. The geothermal credit remains unchanged at 10%.

The credit for fuel cells is capped at $500 per 0.5 kilowatt (kW) of capacity. The maximum microturbine credit is $200 per kW of capacity. No maximum is specified for the other technologies.

Solar energy property includes equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat. Hybrid solar lighting systems are those that use solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight. Geothermal energy property includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. It does **not** include geothermal heat pumps. For electricity produced by geothermal power, equipment qualifies only up to, but not including, the electrical transmission stage. Energy property does not include public utility property, passive solar systems, or pool heating equipment.

To qualify, the original use of the equipment must begin with the taxpayer or it must be constructed by the taxpayer. The equipment must also meet any performance and quality standards in effect at the time the equipment is acquired. The energy property must be operational in the year in which the credit is first taken.

If the project is financed in whole or in part by subsidized energy financing or by tax-exempt private activity bonds, the basis on which the credit is calculated must be reduced. (The formula is described in the tax credit instructions.) Subsidized energy financing means "financing provided under a federal, state, or local program, a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy." Therefore, a business must reduce the basis for calculating the credit by the amount of any such incentives received.

Contact:

Public Information - IRS
Internal Revenue Service
1111 Constitution Avenue, N.W.
Washington, DC 20224
Phone: (800) 829-1040
Web site: http://www.irs.gov

Federal

Residential Solar and Fuel Cell Tax Credit

Incentive Type:	Personal Tax Credit
Eligible Renewable/Other Technologies:	Solar Water Heat, Photovoltaics, Fuel Cells, Other Solar Electric Technologies
Applicable Sectors:	Residential
Amount:	30%
Maximum Incentive:	$2,000 for solar electric and solar water heating; $500 per 0.5 kW for fuel cells
Carryover Provisions:	Excess credit may be carried forward to succeeding tax year
Eligible System Size:	Not specified
Equipment/Installation Requirements:	Solar water heating property must be certified by SRCC or by comparable entity endorsed by the state. At least half the energy used to heat the dwelling's water must be from solar in order for the solar water heating property expenditures to be eligible.
Authority 1:	26 USC § 25D
Date Enacted:	8/8/2005
Effective Date:	1/1/2006
Expiration Date:	12/31/2008

Summary:

Now available: IRS Form 5695 & Instructions: Residential Energy Credits for Tax Year 2006

The Energy Policy Act of 2005 (H.R. 6, Sec. 1335) established a 30% tax credit up to $2,000 for the purchase and installation of residential solar electric and solar water heating property. An individual can take both a 30% credit up to the $2,000 cap for a photovoltaic system and a 30% credit up to a separate $2,000 cap for a solar water heating system. A 30% tax credit up to $500 per 0.5 kilowatt (kW) is also available for fuels cells. Initially scheduled to expire at the end of 2007, the tax credits were extended through December 31, 2008, by Section 206 of the Tax Relief and Health Care Act of 2006 (H.R. 6111).

Solar water heating property must be certified for performance by the Solar Rating Certification Corporation (SRCC) or a comparable entity endorsed by the government of the state in which the property is installed. Note that the tax credit does not apply to solar water heating property for swimming pools or hot tubs.

The credit is calculated based on the individual’s expenditures excluding subsidized energy financing, which is defined as "financing provided under a Federal, State, or local program a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy." *Consumers who receive other incentives are advised to consult with a tax professional regarding how to calculate this federal tax credit.*

If the federal tax credit exceeds tax liability, the excess amount may be carried forward to the succeeding taxable year. Expenditures include labor costs for the onsite preparation, assembly, or original installation of the system and for piping or wiring to interconnect the system to the dwelling.

To be eligible for the credit, a system must be "placed in service" or activated on or after January 1, 2006, and on or before December 31, 2008. Expenditures with respect to the equipment are treated as made when the installation is completed. If the installation is on a new home, the "placed in service" date is the date of occupancy by the homeowner.

Contact:

Public Information - IRS
Internal Revenue Service
1111 Constitution Avenue, N.W.
Washington, DC 20224
Phone: (800) 829-1040
Web site: http://www.irs.gov

Federal

Modified Accelerated Cost-Recovery System (MACRS)

Incentive Type: Corporate Depreciation

Eligible Renewable/Other Technologies: Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Geothermal Electric, Fuel Cells, Solar Hybrid Lighting, Direct Use Geothermal, Microturbines

Applicable Sectors: Commercial, Industrial

Authority 1: 26 USC § 168 (2005)

Effective Date: 1986

Summary:

Under the Modified Accelerated Cost-Recovery System (MACRS), businesses can recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. For solar, wind and geothermal property placed in service after 1986, the current MACRS property class is five years. With the passage of the Energy Policy Act of 2005, fuel cells, microturbines, and solar hybrid lighting technologies are now classified as 5-year property as well. 26 USC § 168 references 26 USC § 48(a)(3)(A) with respect to classifying property as "5-year property" and EPAct 2005 added these technologies definition of energy property in § 48 as part of the business energy tax credit expansion.

For more information, see *IRS Publication 946, IRS Form 4562: Depreciation and Amortization*, and *Instructions for Form 4562*. The IRS web site provides a search mechanism for forms and publications. Enter the relevant form, publication name or number, and click "GO" to receive the requested form or publication.

Contact:

Public Information - IRS
Internal Revenue Service
1111 Constitution Avenue, N.W.
Washington, DC 20224
Phone: (800) 829-1040
Web site: http://www.irs.gov

DSIRE **Federal**

Renewable Energy Production Incentive (REPI)

Incentive Type:	Production Incentive
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Livestock Methane, Tidal Energy, Wave Energy, Ocean Thermal, Fuel Cells using Renewable Fuels
Applicable Sectors:	Tribal Government, Municipal Utility, Rural Electric Cooperative, State/local gov't that sell project's electricity
Amount:	1.5¢/kWh (1993 dollars, indexed for inflation)
Terms:	10 years
Authority 1:	42 USCS § 13317
Date Enacted:	1992 (subsequently amended)
Authority 2:	10 CFR 451
Website:	http://www.eere.energy.gov/repi

Summary:

The Renewable Energy Production Incentive (REPI) provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Qualifying facilities are eligible for annual incentive payments of 1.5¢ per kilowatt-hour (in 1993 dollars and indexed for inflation) for the first 10-year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation.

REPI was originally authorized under Section 1212 of the Energy Policy Act of 1992 and had expired for new projects as of September 30, 2003. However, Section 202 of the Energy Policy Act of 2005 (H.R. 6) reauthorized appropriations for fiscal years 2006 through 2026 and expanded the list of eligible technologies and facilities owners. See 42 USCS § 13317 above for the current REPI statute.

Eligible electric production facilities include not-for-profit electrical cooperatives, public utilities, state governments, Commonwealths, territories, possessions of the U.S., the District of Columbia, Indian tribal governments, or a political subdivision thereof, or Native Corporations that sell the project's electricity to someone else.

Qualifying facilities must use solar, wind, geothermal (with certain restrictions as contained in the rulemaking), or biomass (except for municipal solid waste combustion), landfill gas, livestock methane, and ocean (including tidal, wave, current, and thermal) generation technologies. Fuel cells using hydrogen derived from eligible biomass facilities are also considered an eligible technology.

If there are insufficient appropriations to make full payments for electric production from all qualified facilities for a fiscal year, 60% of appropriated funds are to be assigned to facilities that use solar, wind, ocean (including tidal, wave, current, and thermal), geothermal, or closed-loop biomass technologies; and 40% of appropriated funds for the fiscal year to other projects.

REPI complements Sections 1914 and 1916 of the Energy Policy Act of 1992, which provide tax incentives to certain private sector entities for certain types of new renewable energy generation facilities.

For questions concerning REPI policy issues and the availability of appropriations, email repi@ee.doe.gov. The point of contact on REPI implementation (facility qualifications, applications, and payments) is Christine Carter.

Contact:

Christine Carter
U.S. Department of Energy
Golden Field Office
1617 Cole Blvd.
Golden, CO 80401-3393
E-Mail: christine.carter@go.doe.gov
Web site: http://www.eere.energy.gov/

Information Specialist - REPI
Department of Energy
Weatherization and Intergovernmental Program
Washington, DC
E-Mail: repi@ee.doe.gov
Web site: http://www.eere.energy.gov/

Renewable Energy Property Tax Exemption

Incentive Type: Property Tax Exemption

Eligible Renewable/Other Technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric

Applicable Sectors: Commercial, Industrial, Residential

Amount: 100%

Authority 2: Kansas Statutes 79-201

Effective Date: 1/1/99

Summary:

This statute exempts renewable energy equipment from property taxes. Renewable energy includes wind, solar thermal electric, photovoltaic, biomass, hydropower, geothermal, and landfill gas resources or technologies that are actually and regularly used predominantly to produce and generate electricity .

Contact:

Jim Ploger
Kansas Corporation Commission
Energy Office
1500 SW Arrowhead Road
Topeka, KS 66604-4027
Phone: (785) 271-3349
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E-Mail: j.ploger@kcc.ks.gov
Web site: http://kcc.ks.gov/energy/

D.9 Greensburg, Kansas, Biomass Resource Assessment and Opportunities for Converting and Using Fuels from Biomass

Chris Gaul
March 2008

This report examines biomass resources in Greensburg and Kiowa County and opportunities to create value-added products, including solid fuel pellets, from locally available materials.

Greensburg, Kansas, is located on the southern Great Plains. It is the county seat of Kiowa County. The local economy is based on agriculture. Annual rainfall is 23 inches. Kiowa County in 2006 harvested 23,500 acres of corn and 12,500 acres of soybeans. These crops are grown using center-pivot irrigation drawing water from the Ogallala aquifer. In 2003 there were 53,337 non-irrigated acres in the Conservation Reserve Program (CRP).

Kiowa County Biomass Resource Assessment

Southwest Kansas biomass resources are crop residue and purpose grown energy crops. Residues include corn stover, bean stubble, and wheat straw. Switchgrass is an example of a purpose grown energy crop.

The recent rapid increase in ethanol production has put pressure on corn supply. Corn prices have more than doubled since 2000. High corn prices have led to more corn acres being planted. This makes corn stover the most abundant crop residue in Kiowa County and an attractive solid biofuel resource.

Corn stover includes the stalks, leaves, and roots left in the field after grain is harvested. Stover can be gathered using hay baling equipment. Of primary concern to farmers is the affect removing stover has on soil fertility.

Jim Hettenhaus provides a detailed discussion of corn stover and soil fertility in his article, "The Carbohydrate Economy."[1]

For no-till corn fields yielding 180 bu/acre, available stover is 3.5 tons to 4.5 tons per acre using USDA Best Management Practices. Sokhansanj, Turhollow, and Perlack in 2002[2] calculated stover yield with round balers to be 1.1 tons to 1.5 tons per acre. This was done using typical hay harvest methods of cutting, windrowing, and baling.

Corncobs can be collected during grain harvest with a cob collection attachment to the combine chaff discharge chute. Corncob yields range from 1 ton to 2 tons per acre depending on the corn variety.

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[1] J. Hettenhaus, 2002. Institute for Local Self-Reliance, Vol. 4, Issue No. 2, "The Carbohydrate Economy."
[2] S. Sokhansanj, A. Turhollow, and R. Perlack 2002. Stochastic Modeling of Costs of Corn Stover Costs Delivered to an Intermediate Storage Facility. ASAE Paper 024190 presented at 2002 ASAE Annual International Meeting/CIGR XVth World Congress.

Planting switchgrass on CRP ground yields 6 tons to 8 tons per acre. Switchgrass is a perennial that takes three years to reach full production. When managed for energy production it can be harvested one or two times per year. David Bransby of Auburn University provides a switchgrass profile in a paper with the same title. [3]

Assuming an increase in corn acres and 30% farmer participation, crop residue could be collected from 8,000 acres in Kiowa County. Table 1 shows biomass potentials for Kiowa County.

Table 1. Biomass Potentials for Kiowa County

Biomass	Low tonnage/acre	High tonnage/acre	Kiowa County tons Low	Kiowa County tons High
Corncobs	1	2	8,000	16,000
Corn stover	1.1	4.5	8,800	36,000
Switchgrass on 30% CRP ground	6	8	95,400	127,200

Converting CRP ground to switchgrass production could greatly increase biomass production in the long term. Since CRP contracts run 10 years to 15 years this change would require a decade or more to complete or a change in USDA regulations governing CRP ground.

Crop Residue Recovery Costs

Crop residues have typically been collected using hay baling equipment. This requires additional passes over the filed to cut, windrow, and bale. In 2002 Hettenhaus[1] put stover delivered to processor price at $25 per ton. A sensitivity analysis by Sokhansanj showed diesel fuel cost to have nominal impact on delivered stover price. Adjusting for higher fuel prices and 20% inflation for 2002-2009 stover delivered to Greensburg is assumed to cost $35 per ton.

Before combines became the norm, corn was harvested with corn pickers that took the entire ear from the stalk. Corn was air dried and shelled. This multistep operation accumulated mostly intact cobs in a pile. Cobs were used as feedstock to produce furfural using the Quaker Oats process or more commonly spread on roads during muddy season. Combine harvesters separate grain from cobs in one combined machine, hence the name *combine*. Cobs are ejected out the rear of combines onto the field along with leaves and chaff. At this point they are basically impossible to collect. If field collection machinery was available the cobs would be contaminated with dirt.

Cobs need to be collected before they hit the field. Two methods have been tested by combine manufacturers. One mixes grain and broken cobs in the grain tank. They are separated in a

[3] D. Branby. Auburn University, "Switchgrass Profile," (archived at ORNL Bioenergy Feedstock Development Program).

second process after the grain/cob mix is unloaded. The other method uses a towed "cob caddy" to collect cobs from the rear of the combine.

Cobco® of Nebraska City, NE, has a well developed cob collection attachment that captures corncobs at the rear of a combine and stores them in a separate top tank. Leaves and chaff are ejected to the field. The Cobco® collector does not use a towed wagon which simplifies harvest in small fields or hilly terrain. Like other cob collection methods both grain and cobs are collected in one pass over the field.

Cob collection on a large scale is a harvest problem that likely will be solved soon. Poet LLC, a large ethanol producer, is projecting its Project Liberty to come on-line in 2011. It will require corncobs from 275,000 acres to supply its cellulosic ethanol plant in Emmetsburg, Iowa. In addition to cob collection the best methods to store cobs are being developed. Cobs are harvested in the fall but ethanol production is year around. The same storage techniques will be needed for a pellet fuel plant.

Cob production costs are driven by equipment costs. Cobco® equipment, while not in serial production, is projected to cost on the order of $50,000. Amortizing over two years and harvesting 3,000 tons per year puts cob production costs at less than $10 per ton.

Liquid Fuels

Corn Ethanol

Corn ethanol production is rapidly expanding in Kansas[4] . By 2010 Kansas may have 1,300 million gallons/year of ethanol production from corn and milo. Extrapolating from existing grain consumption this will require about 500 million bushels of grain. This exceeds the 2006 Kansas crop. In 2007 corn and milo production increased to 711 million bushels. This increase was driven by higher prices for ethanol feedstock grains[5] .

The Greensburg area has corn-ethanol plants up and running. Pratt, 30 miles east, has a 55 million gallon per year (MGY) plant. Garden City, 100 miles west, also has a 55 MGY plant, and Russell 120 miles north a 48 MGY ethanol production facility.

Greensburg is as well situated as these other cities for ethanol production. It is on a railroad line, has water, grain, and natural gas. The local grain supply may become overwhelmed by ethanol demand. For example, the Gateway Ethanol plant in Pratt produces 55 MGY. Assuming 2.5 gallons/bushel corn and 200 bushels/acre irrigated corn this one plant will require 110,000 acres of corn. This is more than all the corn grown in Kiowa and Pratt Counties in 2006.

Corn ethanol production is now an established industry using mature technology. This report will not delve further into constructing a corn ethanol plant in Greensburg.

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[4] December 21, 2007. Kansas Ethanol Clean Fuel from Kansas Farms: Kansas Ethanol Production. www.ksgrains.com/ethanol/kseth.html

[5] Eldon Thiessen. November 9, 2007. U.S. Department of Agriculture, National Statistics Service, "November Crop Estimate Shows 45% increase for Kansas Feed Grains."

Cellulosic Ethanol

Cellulosic ethanol is made from crop residues such as corn stalks (stover) and wheat straw or purpose grown energy crops such as pulp wood and switchgrass,

The appeal of cellulosic ethanol is that it does not divert food crops to energy production. Using corn stover or wheat straw to make ethanol is using a resource that typically decomposes in the field. For every ton of corn grain there is a ton of residue that a portion can be used for ethanol production. The resource is there ready to be gathered. There is no need to convert land to growing another crop.

A common concern among farmers is that removing crop residue will reduce soil fertility. While some of the crop residue returns to the soil to maintain fertility, not all of it is necessary. Studies have shown that when using no-till farming techniques, typically 50% of corn stover can be removed without adversely affecting fertility. One reason is as microorganisms decompose the stover above ground, the plant carbon goes straight to the atmosphere as $CO2$. It never reaches the soil to add fertility for the next crop.

Southwest Kansas is heavily irrigated using Ogallala Aquifer water. This essentially non-renewable resource has been depleted in some regions, especially the Texas Panhandle. Corn production would fall dramatically if the region had to depend on 23 inches of natural rainfall. A sustainable alternative to corn and stover for ethanol feedstock is switchgrass. This native prairie grass grows three to six feet tall. Its deep roots can tap subsoil moisture out of reach to corn plants. It is adapted to the harsh climate of the Great Plains. Switchgrass does not need irrigation or annual field preparation. It is a perennial that, like hay, yields multiple annual cuttings.

Looking to the future the demand for ethanol has really just begun. In 2000, the U.S. produced 1.63 billion gallons of ethanol. Under legislation signed December 19, 2007, the federal government is calling for 36 billion gallons by 2022, of which 21 billion gallons will be based on feedstocks other than corn. Cellulosic ethanol will surpass corn-ethanol production as the technology matures. Ten years ago corn-ethanol technology was a risky proposition. Today the risk lies in corn, ethanol, and fossil fuel prices being aligned to make a plant profitable. The engineering knowledge base has matured to the point that the technology to convert corn into ethanol is no longer risky.

The U.S. Dept. of Energy (DOE) has researched cellulosic or biomass ethanol production for 30 years at its National Renewable Energy Laboratory (NREL) and other labs. Cellulosic ethanol has moved from the lab to production facilities. In Hugoton, 125 miles west of Greensburg, Abengoa is building a 30 MGY cellulosic ethanol plant along with an 85 MGY corn plant[6].

The U.S. DOE is providing funds toward construction of six cellulosic ethanol plants. With government support and favorable market conditions cellulosic ethanol technology should develop along the same lines at corn ethanol.

Greensburg could be well situated for a cellulosic ethanol plant. It has the necessary transportation and energy infrastructure. In the near term there will be abundant residues from

[6] T. Carpenter, November 11, 2007. The Capital Journal, “Other Sources Emerge for Ethanol Creation.”

grain fields feeding corn and milo ethanol plants. In the long term if irrigation water is no longer available, cellulosic ethanol plants can be supplied with switchgrass instead of corn stover.

Biodiesel

Biodiesel is produced from oilseed crops such as soybeans and canola. On December 4, 2007, Torsten Energy announced plans for a 30 MGY to 40 MGY biodiesel plant in Greensburg. The primary feedstock is expected to be soybean oil brought by railcar from Kansas processing bean plants[7].

Solid Fuels

Biomass is the original solid fuel. For thousands of years humans depended on wood fuel. Coal mining at one time was actually an environmental benefit because it reduced pressure on forests to supply fuel for the Industrial Revolution.

Greensburg and Kiowa County obviously do not have enough trees for a large firewood industry. However, there are abundant crop residues that, unlike trees, provide a harvest every year. Biomass can be converted into solid fuel with much less effort than liquid fuels.

Compacted Biomass

Biomass pressed into pellets and other forms are used for solid fuel applications. Corn stover, corncobs, wheat straw, switchgrass, and wood can be formed into an easily handled product that can be distributed in bulk or bag.

Wood pellets are widely used in forested regions such as New England and the Rocky Mountains. The pellets are made to standard specifications for size and moisture content. They are typically sold in 40 pound sacks for use in residential and light commercial heating equipment. Greensburg crop residues could be extruded into pellet fuel.

Larger than pellets are bripells. Bripells originated in Brazil where they are made from bagasse, the residue of sugarcane harvest, to fire steam boilers. Bripells are new to the American market. They are similar to pellets but are larger in diameter ranging from 1.5 to 10 inches. Bripells require 75% less energy to extrude than pellets giving them a $15/ton production cost advantage.

Biomass pellets or bripells represent a business opportunity for Greensburg. A single bripell line can produce 12-15,000 tons/year of product. It would take 4,000 acres of corn stover to supply the raw material for one bripell line.

Bripells and pellets can be produced from corncobs, corn stover, and wheat middlings. These solid fuels could be used locally to heat homes and businesses. A bulk truck could deliver pellet fuel to a storage hopper much as propane is delivered. More distant deliveries would be in conventional 40-pound sacks shipped by the pallet and truckload.

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[7] M. Anderson, December 4, 2007. The Pratt Tribune, "Biodiesel in the Offing for Greensburg." http://pratttribune.com/articles/2007/12/04/news/01.eml

An export market is developing for compressed biomass pellets, bripells and briquettes. The EU is importing compressed biomass as a carbon-neutral substitute for coal. Greensburg is on a main railroad line with access to seaports. The shipping distance may be too far even by rail to keep costs low enough to compete with compressed biomass plants located near seaports.

Biomass co-firing in coal electric generating stations

Biomass can be used in conventional power plants to reduce greenhouse gas (GHG) emissions. For example, the coal-fueled 725 MW Ottumwa Generating Station in Chillicothe, Iowa is being co-fired with biomass to cut GHG. The plant will consume 200,000 tons of switchgrass per year. This energy crop will require 80,000 acres to 100,000 acres.

GHG emissions are now a consideration for Kansas electric power producers. On October 18, 2007, KDHE denied Sunflower Electric licenses to build three coal burning electric generating stations at Holcomb because they would produce 11 million tons per year of GHG.

Kiowa County in 2003, had 53,337 acres of Conservation Reserve Program (CRP) land. Based on Ottumwa area yields of 2 tons/acre this land area could produce 100,000 tons of switchgrass. In 2006 the county had 23,500 acres of corn from which another 100,000 tons of stover and cobs could be collected. Together there would be sufficient biomass to co-fire a Kansas electric generating station. While biomass could not compete with cheap coal on price alone, it represents a relatively simple way for a coal-based utility to reduce its GHG emissions. With its excellent location on the Union Pacific Railroad, Greensburg could ship compressed biomass to many coal-fired electric generating stations.

Residue collection

Crop residues are typically baled after grain is harvested. Corn will produce as much stover as grain by weight, typically 4 tons to 6 tons per acre of which half can be removed in a sustainable manner. A 130 acre circle of irrigated corn yields 260 tons to 390 tons per acre of stover.

Corncob yields vary from 1 ton to 2 tons per acre depending on what variety of corn is planted. Corncobs are difficult to collect once they are ejected from a combine onto the field. There are a few prototype cob collection systems. Cobco of Nebraska City, Nebraska, has a well developed cob collection attachment that captures corncobs at the rear of a combine and stores them in a separate top tank. This device keeps the cobs clean, does not require a separate towed wagon, and does not require additional passes over the field.

Cogeneration using biomass pellets

The simplest use for compressed biomass is to burn it. This works fine for thermal loads but is inefficient for electric generation. Community Power Corporation of Littleton, Colorado, builds Biomax modular biomass fueled generators. It converts biomass into gaseous fuel that is burned in a piston engine. In addition to electric power waste heat is captured from the engine water jacket and exhaust gas stream. Biomax systems range from 5 KW to 100 kW of electricity. They can be configured to run on most crop residues and are well-suited to compressed biomass pellets and bripells. These units require more maintenance and operation than a standard diesel or propane engine generator. Community Power says a Biomax is a 24/6 machine that requires weekly attention.

Manure

Southwest Kansas has been cattle country since the 19th century. Dodge City, 50 miles west of Greensburg, has a thriving beef packing industry supplied by numerous feedlots. All these bovines produce an abundance of the plain's original renewable energy-manure.

Handling manure in an environmentally sound manner is a serious problem for confined animal feeding operations (CAFO). E3 BioFuels of Shawnee, Kansas has developed an integrated system combining ethanol production with cattle or dairy operations. In a typical corn ethanol plant the fermentation residue, called distillers grain, is sold for cattle feed. Distillers grain is typically dried so it does not spoil during shipment using natural gas fuel. This increases ethanol cost and hurts the energy balance of fossil-fuel input versus renewable energy output.

The E3 system collects cow manure into a digester that makes methane gas to power the plant. After digestion the manure still has value as fertilizer. Distillers' grain does not have to be dried because it is produced adjacent to the feedlot and fed before it can spoil. This reduces energy demand. A properly proportioned system uses little off-site energy. It takes in corn and produces beef or milk, ethanol and fertilizer.

E3 Biofuels recently filed bankruptcy. The company states it was due to start up problems typical of any new technology plant affecting cash flow. Despite the E3 business setback, Panda Ethanol and Chippewa Valley Ethanol are working along similar lines.

Greensburg could pursue this in several ways. It could establish large cattle feeding operations combined with ethanol production. Cattle would supply the Dodge City market. Large feedlots are well known but large dairies are relatively new[8] . Instead of a few dozen Herefords, new large dairies have thousands of cows. Dairy is a growth industry in western Kansas. Kansas State University Animal Sciences and Industry had this perspective:

"Kansas has become a major dairy state during the past decade. In 1996, Kansas ranked 30th in total milk production, 29th in dairy cow numbers and 34th in milk production per cow in the U.S. About 1,000 permitted dairy herds existed in 1996. Since then, a major expansion of the dairy industry has occurred in western Kansas and in long-established dairy enterprises elsewhere in the state. At the end of 2006, Kansas ranked 17th in total milk production, 19th in dairy cows and 9th in milk production per cow. At the end of 2006, Kansas had 112,000 dairy cows on 441 permitted dairies. Kansas is considered to be a major dairy expansion state and likely will continue to expand."

Greensburg could follow this industry trend and profit from jobs associated with a dairy/ethanol plant. It could also purchase surplus electric power generated from manure.

<u>Economics</u>

Wood pellets are a high volume, low-margin business. According to Forest Energy Products President Rob Davis, the cost to build an optimum sized 8 ton per hour (65,000 tons per year)

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[8] B. Jackson, March 4, 2007. Greeley Tribune, "Building one big barn: Dairy structure will be world's largest of its kind." bjackson@greeleytribune.com

plant processing wood into pellets is $8 million. Shipping cost for bagged product limit distribution to 300 miles from the pellet mill to market. If the truck line has a back haul, product shipping costs can be reduced.

The Pellet Fuel Institute is a trade organization that set specifications for fuel pellets. The grades are: standard, premium and super premium. Standard pellets are less than 2% ash content, premium 1%, and super premium 0.5%. Corn stover in lab tests is 1.5% ash content. This is too high for the most widely sold pellet fuel grades. High ash content produces clinkers and firing problems in residential pellet stoves.

The selling price for standard-grade pellets would be driven by natural gas prices, which is the primary source for residential heat in the Greensburg market area. Arranging for contracts with mass marketers such as Lowe's and Home Depot is highly competitive.

Bert & Wetta Sales, an alfalfa pellet mill in Larned, Kansas, has pelletized wood and some agricultural waste. They were able to do this to fill in between their main alfalfa pellet. In this case, the plant was fully amortized. A new pellet mill would have much higher costs to pay for plant equipment.

Prospects

The biomass potential in Kiowa County ranges from 8,000 tons per year to more than 100,000 tons per year. There does not seem to be a viable market for pellet fuels exported from the county. The best prospect is to use local biomass to displace fossil fuel in a local energy-intensive business. Instead of trying to enter a mass market such as wood fuel pellets, this approach would require only one or a few large customers.

Such businesses exist near Greensburg. Dodge City's meat packing plants require natural gas fuel. Ethanol plants typically use natural gas to dry distillers grain. By modifying gas boilers to burn biomass these large users could switch to a renewable fuel less prone to price increases.

The business model would be biomass, which would be collected and processed at Greensburg and shipped by truck or rail end users. At the current natural gas price of $10/million BTU, the delivered price would need to be under $130 per dry ton. An industrial plant could depend on a steady fuel cost instead of wild fluctuations.

An example of this business model is Prairie Fire BioEnergy Cooperative in Healy, Kansas. This town is similar to Greensburg in many ways. It has the same agricultural based economy, it is located on a railroad line, and has been challenged by a declining population. The Prairie Fire Coop is building a local business to produce biofuels for large users. They have entered into negotiations with Sunflower Electric to provide biofuels to co-fire in the utility's coal fired electric generating stations.[9, 10]

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[9] S. Miller. 2008. Sunflower Electric Corporation. Media Release. www.sunflower.net; smiller@sunflower.net
[10] Mike Corn. October 2007. The Hays Daily News, "Biomass Looks for a Boost."

Conclusions

The barriers to converting Kiowa County crop residues into pellet stove fuel are high ash content, substantial startup costs, low profit margin and distant markets.

Biomass could be converted into a lower grade industrial fuel for large users such as meat packinghouses or ethanol plants. It could be co-fired with coal in electric generating stations. With Greensburg's transportation connections biomass fuel could be shipped by rail or truck to Kansas markets. If Greensburg develops and industrial park the biomass processing plant could provide heat to the park and solid fuels to export outside Kiowa County.

Recommendation

Greensburg business leaders should contact Prairie Fire Coop and see if a similar business could be established in Greensburg.

Contacts

Prairie Fire BioEnergy Cooperative of Healy, Kansas is a non-profit, producer owned, cooperative founded to support the development of renewable biomass energy sources in western Kansas. Prairie Fire will manufacture a biomass fuel for use in industrial furnace and electrical power generation. Ingredients in their biosolid fuel are renewable biomass inputs such as baled hay, out of condition hay, seed hulls, crop stubble, and other products. Visit Prairie Fire's website at: http://www.prairiefirecoop.com/
Media Contact**:** Brad Applegarth – Telephone 620. 398.2370
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Bripells

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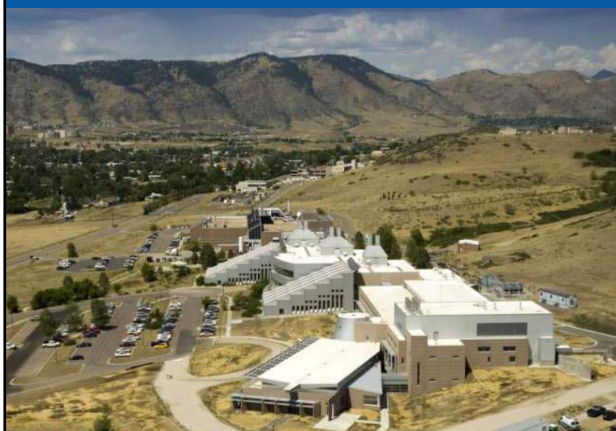
D.10 Biomass Pellet Options for Greensburg and Surrounding Regions

Scott Haase
National Renewable Energy Laboratory

NREL National Renewable Energy Laboratory
Innovation for Our Energy Future

Biomass Pellet Options for Greensburg and Surrounding Regions



Scott Haase

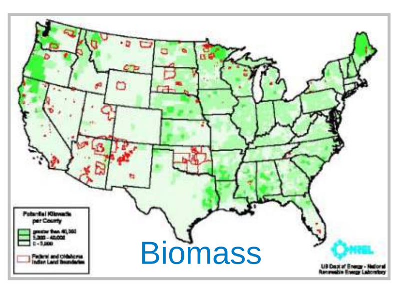
February 11, 2009

Greensburg, KS

NREL is a national laboratory of the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy operated by the Alliance for Sustainable Energy, LLC

Presentation Outline

- Project goal and objectives
- Product definition
- Biomass resource assessment
  - Quantity, cost, characteristics
- Market demand
  - Comparative costs of various fuels
  - Regional natural gas use
  - Potential customers
- Equipment
  - Pellets and conversion appliances
- Suggested next steps



Project Goal and Objectives

Goal

- Identify and evaluate opportunities to create a pellet plant in or around Greensburg

Objectives

- Understand the local biomass resource base
- Assess characteristics of pellets made from local feedstocks
- Understand economics of the process
- Assess the local market and potential demand
- Suggestions for next steps

Product definition

Ag residue and wood blend pellets (or briquettes, bripells)

- Similar to pellets made by Show Me Energy Co-operative of Centerview, MO
  - 7,000 – 7,500 Btu/lb
  - High ash (between 3 and 10 percent)
  - High alkalis (leads to slagging)
- Pellet market is presently dominated by low ash, low alkali products – “premium pellets”
- Classic “chicken and egg” problem to develop this opportunity

Business Overview

- Procure local biomass feedstocks
- Densify at centralized plant
- Provide bulk delivery to local and regional customers
- Local customers burn pellets instead of fossil fuels for thermal energy needs

Local Biomass Resources and Issues

Wood Residues
Eastern Red Cedar

Agricultural Residues
Corn stover
Wheat straw
Sorghum residue
Soybean residues

Energy Crops
Convert CRP land to switchgrass

Cost
- Production
- Collection and transportation
- Quantity available
- Supply infrastructure
- Storage

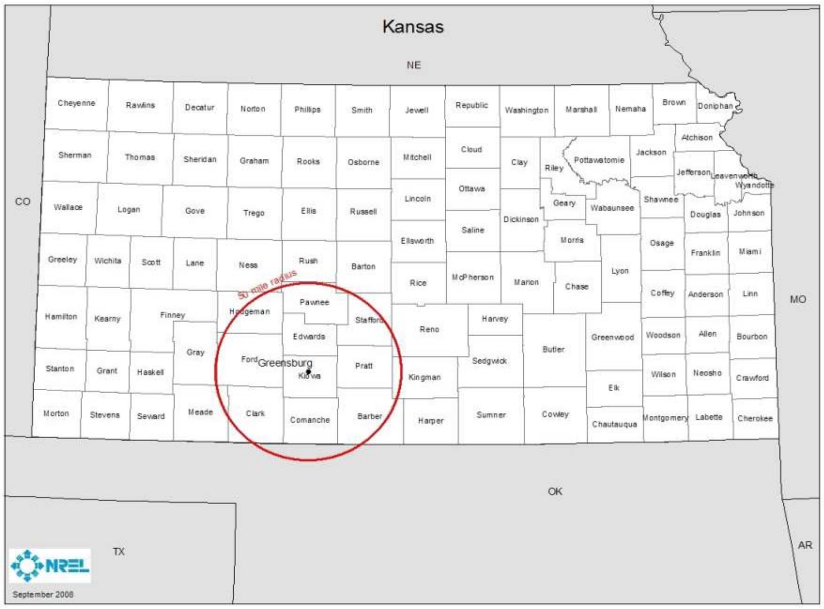
Sustainability
- Land, air and water resources

Quality
- Composition

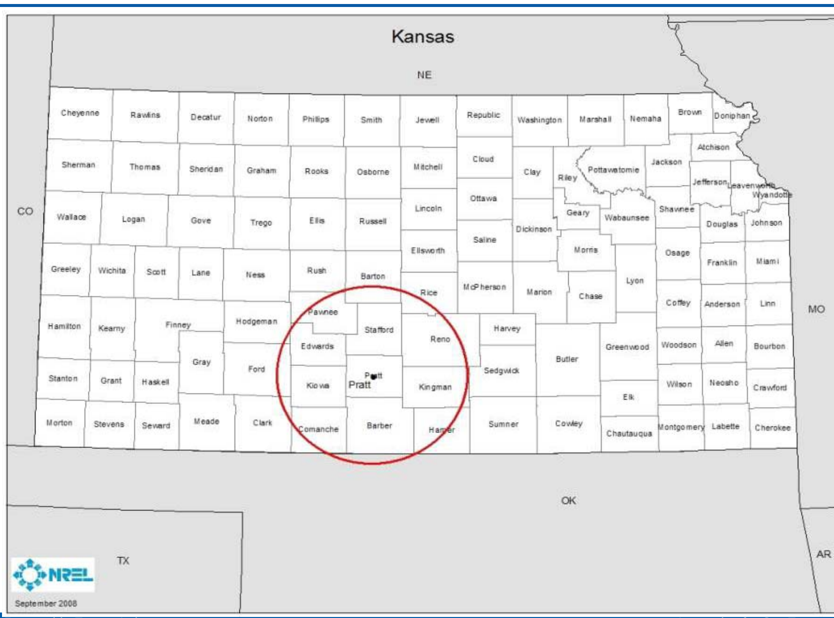
Ease of Conversion

Others
Landfill gas, manure
Municipal solid waste
Not considered

50 Mile Radius from Greensburg



50 Mile Radius from Pratt



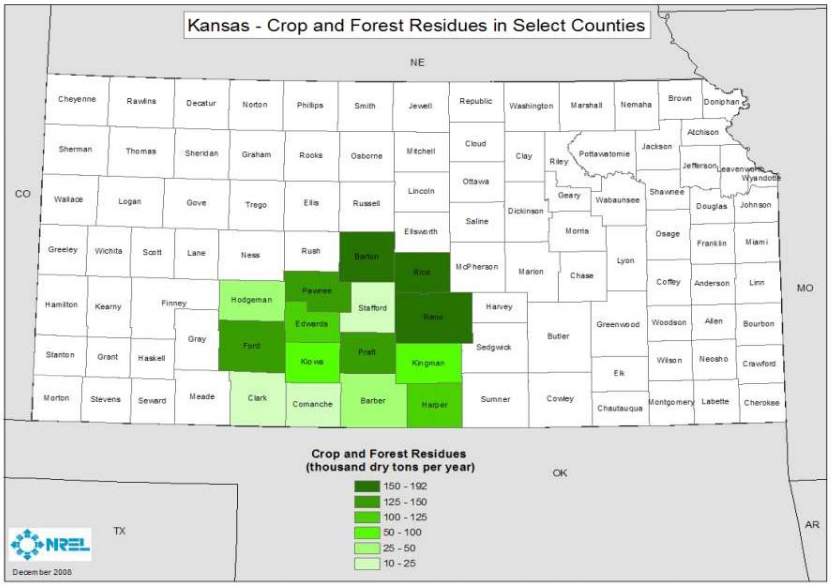
Biomass Assessment - Methodology

- Developed list of counties within 50 miles of Pratt and Greensburg
- Obtained 10 years worth of data from USDA National Agricultural Statistics Service
  - Calculated 10 year averages of acres planted, acres harvested, crop yield
- Calculated residue quantities based on crop production
- Calculated "residue leave" factors for nutrient cycling and erosion protection
  - Cotton, sorghum, soybeans > assume 35% is available
  - Corn, wheat > based on factors by Richard Nelson, Kansas State University

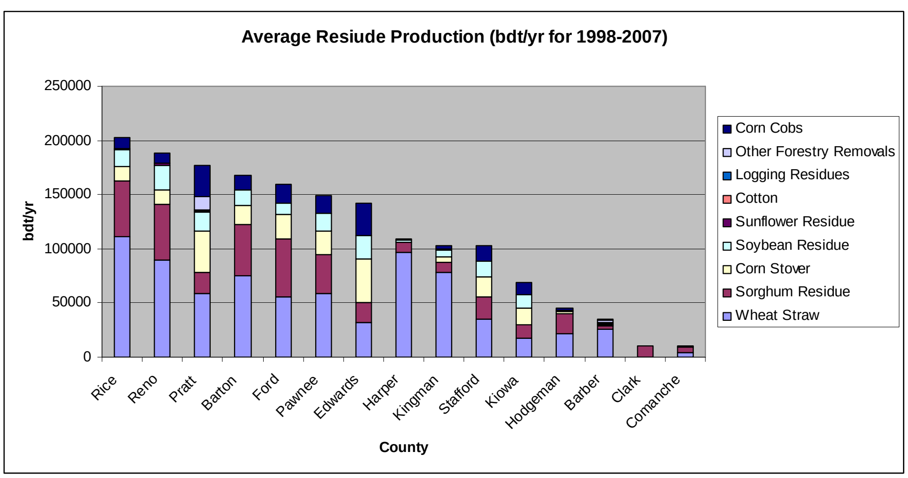
Summary of Major Residues in Region

	Residues Available (bdt/yr)									
County	**Wheat**	**Corn**	**Sorghum**	**Soybean**	**Sunflower**	**Cotton**	**Logging Residues**	**Other Forestry Removals**	**Corn Cobs**	**Total**
Barber	25,283	407	4,004	1,337	46	210	161	2,818	623	34,888
Barton	74,604	17,556	47,399	14,320	222	-	22		14,760	168,882
Clark	469		9,681	345	-	-	-		218	10,713
Comanche	3,835	285	5,357	627	-	-	-		450	10,554
Edwards	31,955	39,921	18,599	21,961	60	-	-		31,913	144,409
Ford	55,368	22,632	53,883	10,214	136	-	-		21,533	163,765
Harper	96,815	146	9,270	1,821	65	436	0		135	108,687
Hodgeman	21,536	2,228	18,130	1,287	-	-	-		4,200	47,380
Kingman	78,586	5,270	8,869	6,458	185	-	-		3,810	103,177
Kiowa	17,281	15,562	12,205	12,255	24	-	-		15,113	72,438
Pawnee	59,127	21,710	35,327	16,494	52	-	-		18,915	151,626
Pratt	58,679	38,472	19,270	17,711	377	1,122		12,500	33,533	181,663
Reno	89,693	13,495	51,240	22,829	1,253	-	15		13,118	191,642
Rice	111,254	14,194	50,816	15,130	931	-	24		8,190	200,539
Stafford	35,258	18,182	20,366	14,845	85	-	-		31,935	120,670
Total	**759,742**	**210,058**	**364,416**	**157,632**	**3,435**	**1,768**	**222**	**15,318**	**198,443**	**1,711,034**

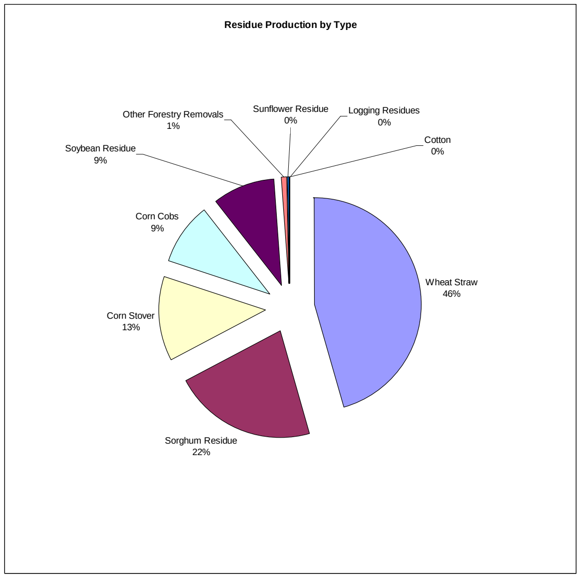
Residue Distribution



Residue Distribution by County



Residue Production, by Type



Corn, Wheat, and Sorghum

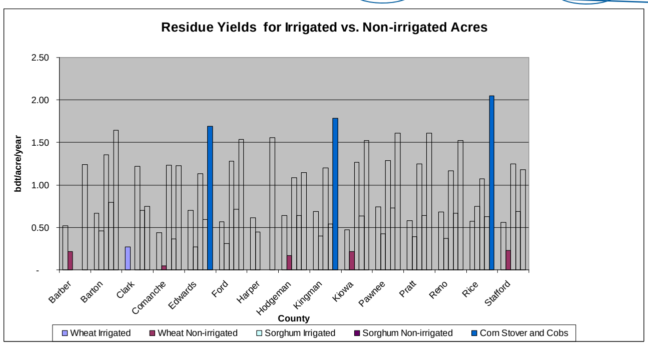
County	Wheat (bdt/yr)			Sorghum Residues (bdt/yr)			Corn (bdt/yr)			Total
	Irrigated	Non-irrigated	Total	Irrigated	Non-irrigated	Total	Irrigated	Non-irrigated	Total	
Barber	881	24,401	25,283	-	-	4,004	407	-	407	29,694
Barton	795	73,809	74,604	2,965	23,686	47,399	17,556	-	17,556	139,559
Clark	469	-	469	232	4,313	9,681	-	-	-	10,150
Comanche	979	2,856	3,835	443	899	5,357	285	-	285	9,477
Edwards	9,198	22,757	31,955	3,490	9,488	18,599	39,921	-	39,921	90,476
Ford	8,846	46,522	55,368	12,791	41,092	53,883	22,632	-	22,632	131,882
Harper	18	96,797	96,815	-	-	9,270	146	-	146	106,231
Hodgeman	5,167	16,369	21,536	2,911	13,951	18,130	2,228	-	2,228	41,893
Kingman	3,746	74,840	78,586	825	3,450	8,869	5,270	-	5,270	92,725
Kiowa	4,025	13,256	17,281	2,569	5,239	12,205	15,562	-	15,562	45,047
Pawnee	9,040	50,087	59,127	5,898	18,477	35,327	21,710	-	21,710	116,165
Pratt	6,375	52,304	58,679	2,895	8,558	19,270	38,472	-	38,472	116,420
Reno	5,528	84,165	89,693	3,424	29,647	51,240	13,495	-	13,495	154,428
Rice	658	110,596	111,254	824	9,894	50,816	14,194	-	14,194	176,264
Stafford	7,116	28,142	35,258	2,985	10,960	20,366	18,182	-	18,182	73,805
Total	**62,841**	**696,901**	**759,742**	**42,252**	**179,653**	**364,416**	**210,058**	**-**	**210,058**	**1,334,216**

County	Irrigated Corn Acres	Non-irrigated Corn Acres	Total Corn Acres	Irrigated Sorghum Acres	Non-irrigated Sorghum Acres	Total Sorghum Acres	All Irrigated Wheat Acres	All Non-irrigated Wheat Acres	Total Wheat Acres
Barber	830	610	2,300	0	0	8,030	1,690	112,340	114,030
Barton	19,680	6,640	26,320	2,190	29,770	55,230	1,190	160,470	161,660
Clark	290	90	1,030	190	6,150	14,910	1,720	57,230	58,950
Comanche	600	140	1,260	360	2,450	9,800	2,240	60,060	62,300
Edwards	42,550	8,850	62,370	3,080	15,920	26,300	13,110	84,440	97,550
Ford	28,710	1,900	46,860	9,990	57,700	67,690	15,540	150,570	166,110
Harper	180	250	1,080	0	0	16,300	30	218,790	218,820
Hodgeman	5,600	1,510	9,680	2,680	21,800	26,100	8,080	96,690	104,770
Kingman	5,080	1,440	7,950	690	6,380	14,970	5,460	187,270	192,730
Kiowa	20,150	4,440	27,610	2,030	8,270	16,710	8,540	60,720	69,260
Pawnee	25,220	3,900	31,400	4,580	25,330	42,760	12,170	118,640	130,810
Pratt	44,710	8,650	59,780	2,320	13,420	27,440	11,040	134,620	145,660
Reno	17,490	7,860	25,350	2,930	44,360	71,870	8,130	225,930	234,060
Rice	10,920	10,770	21,690	770	15,760	59,820	1,150	147,870	149,020
Stafford	42,580	18,870	61,450	2,400	15,910	27,210	12,780	123,420	136,200
Total	**264,590**	**75,920**	**386,130**	**49,100**	**339,970**	**578,040**	**158,790**	**2,108,690**	**2,267,480**

Residue Yields Per Acre

County	Wheat (bdt/acre)			Sorghum Residues (bdt/acre)			Corn (bdt/acre)
	Wheat Irrigated	Wheat Non-irrigated	Wheat Total	Sorghum Irrigated	Sorghum Non-irrigated	Sorghum Total	Corn Stover and Cobs
Barber	0.52	0.22	0.22			0.50	1.24
Barton	0.67	0.46	0.46	1.35	0.80	0.86	1.64
Clark	0.27	-	0.01	1.22	0.70	0.65	0.75
Comanche	0.44	0.05	0.06	1.23	0.37	0.55	1.23
Edwards	0.70	0.27	0.33	1.13	0.60	0.71	1.69
Ford	0.57	0.31	0.33	1.28	0.71	0.80	1.54
Harper	0.61	0.44	0.44			0.57	1.56
Hodgeman	0.64	0.17	0.21	1.09	0.64	0.69	1.15
Kingman	0.69	0.40	0.41	1.20	0.54	0.59	1.79
Kiowa	0.47	0.22	0.25	1.27	0.63	0.73	1.52
Pawnee	0.74	0.42	0.45	1.29	0.73	0.83	1.61
Pratt	0.58	0.39	0.40	1.25	0.64	0.70	1.61
Reno	0.68	0.37	0.38	1.17	0.67	0.71	1.52
Rice	0.57	0.75	0.75	1.07	0.63	0.85	2.05
Stafford	0.56	0.23	0.26	1.24	0.69	0.75	1.18
Average	**0.51**	**0.26**	**0.28**	**1.05**	**0.52**	**0.58**	**1.47**

Highest yields per acre come from irrigated corn and irrigated sorghum



Eastern Red Cedar

- Important regional feedstock for pellet plant
- Will be needed to blend with ag residues to reduce ash and alkali content
- May be the limiting factor on the size of the plant
- Don Queal estimates at least 25,000 green tons per year could be collected

CRP Land Conversion

- Potential to convert CRP lands to switchgrass
- 4.5 bone dry tons (bdt)/acre/yr yield
- Assume 10% of CRP land is converted
- 120,000 bdt/year
- Switchgrass is not a great feedstock for pellets (more later)
- Another approach being done in MN is to grow mixed prairie grasses for feedstock – higher yields than switchgrass

County	CRP Acres
Kiowa	53,337
Comanche	43010
Clark	52,114
Barber	21,018
Pratt	47,750
Ford	59,469
Edwards	34,101
Total	**310,799**

Corn Cobs

- Poet Ethanol is implementing cob collection in Iowa for cellulosic ethanol
  - Working with equipment vendors (John Deere) to develop process
- We estimate 0.75 bdt/acre from irrigated lands
- About 200,000 bdt/year in region

County	Irrigated Corn Acres	Non-irrigated Corn Acres	Total Corn Acres
Barber	830	610	2,300
Barton	19,680	6,640	26,320
Clark	290	90	1,030
Comanche	600	140	1,260
Edwards	42,550	8,850	62,370
Ford	28,710	1,900	46,860
Harper	180	250	1,080
Hodgeman	5,600	1,510	9,680
Kingman	5,080	1,440	7,950
Kiowa	20,150	4,440	27,610
Pawnee	25,220	3,900	31,400
Pratt	44,710	8,650	59,780
Reno	17,490	7,860	25,350
Rice	10,920	10,770	21,690
Stafford	42,580	18,870	61,450
Total	264,590	75,920	386,130

Overall Resource Potential

Feedstock	Bone dry tons/year	Energy equivalent (MMBtu/yr)	Equivalent Therms/yr
Agricultural residues	1,497,051	23,054,588	230,545,879
Cedar and other wood	15,540	273,501	2,735,014
10% CRP Land	120,000	1,752,000	17,520,000
Corn cobs	198,000	3,168,000	31,680,000
Total	**1,830,591**	28,248,089	282,480,893

Average natural gas use of 280,000 homes

	BDT/yr within 25 Mile Radius				BDT/yr within 50 mile radius			
	Crop Residues	Logging and Primary Mill Residues	Urban Wood and Secondary Mill Residues	Total	Crop Residues	Logging and Primary Mill Residues	Urban Wood and Secondary Mill Residues	Total
Pratt	199,100	16,755	1,470	217,325	1,320,000	16,777	9,363	1,346,140
Greensburg	266,200	-	-	266,200	1,100,000	16,755	7,480	1,124,235

- There should be at least 3x the resource above the needs of the plant
- To keep biomass collection costs low, estimate pellet plant should be no larger than 70k – 80k tons/yr input, which will be 50k – 70k tons output, depending on moisture content
- **But the plant size may be limited by cedar resource base (more later)**

25 Mile Radius from Pratt

So Why Is Yield Important?

Assume access to 25,000 bdt/yr cedar, and we want a 50-50 blend of wood and ag residues

How much land area is needed for 25,000 bdt/yr ag residues?

Feedstock Type	Acres Needed/yr	Sections	Number of Center Pivot Circles (126 acre)
Irrigated Wheat	48,804	76	387
Non-irrigated Wheat	95,907	150	
Irrigated Sorghum	23,756	37	189
Non-irrigated Sorghum	47,972	75	
Irrigated Corn Stover	34,654	54	275
Corn cobs from irigated corn	33,333	52	265
Half corn stover/half cob	16,997	27	135
Switchgrass @ 5 bdt/acre	5,000	8	40

Biomass Physical And Chemical Properties

Value	Wheat Straw	Freshly Cut Cedar	Seasoned Cedar	SMEC Pellets
Btu content as received HHV (Btu/lb)	7,125	8,143	8,056	7,059
Btu content bone dry (Btu/lb)	7,709	8,827	8,976	7,680
Moisture content as received (%)	7.57	7.75	10.25	8.09
Percentage Ash (%)	7.83	1.63	0.88	9.04
Lbs Alkali/Mmbtu	1.3	0.08	0.05	1.44
Lbs ash/MMBtu	10.99	2.00	1.09	12.81
Potassium in ash as K2O (%)	11.4	3.25	4.55	10.8

- Ag residues are high in ash and alkalis, moderate energy content
- Values greater than 0.4 lbs alkali/MMBtu have been found to lead to significant risks for slagging and forming clinkers in boilers
- Cedar is highest quality feedstock in the region and likely needs to be blended with ag residues to create quality pellet

Biomass Collection Costs ($/bdt)

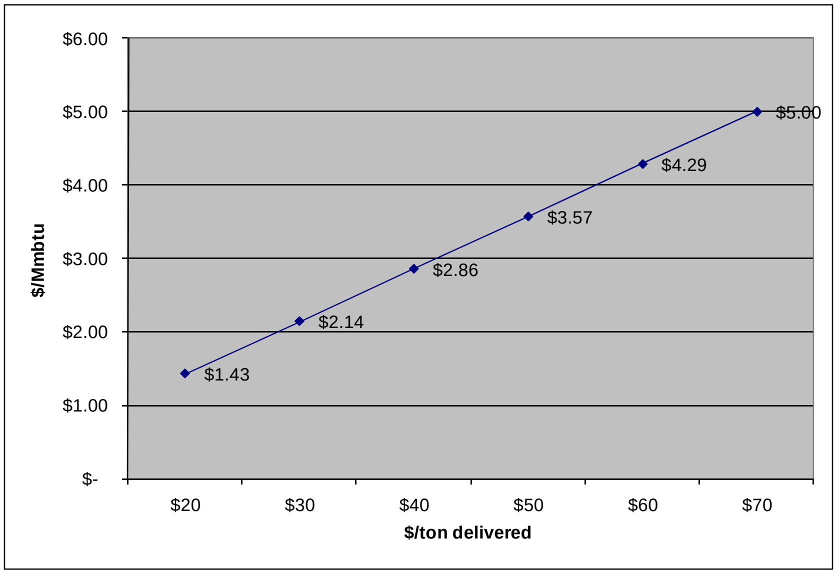
Feedstock	Source	Delivered Cost ($/bdt)
Corn stover (500 to 2000 bdt/day)	ORNL, 2002	**$52.00 - $56.00** (in 2008 $)
Corn stover	CARD, 2007	**$68.50** ($58.26 per 15% moisture content ton)
Corn stover	Campbell	**$61.52**
Soybean straw	Campbell	**$40.70**
Wheat straw	Campbell	**$62.90**

- Feedstock is 40% - 60% of pellet cost (cost of making pellets is $80 - $120 ton)
- Cost must be low for pellet mill, but high enough for producers to participate

Interview With Local Producer

- $20 - cost to bale the straw (summer 2008)
- $5 - to get it to roadside
- $5 - bale profit
- $5 - bale transportation ($0.25/mile for 20 miles)
- $7 - bale loading and unloading for hauler
- Total $42/bale
  - Assume 5 ft x 6 ft round bale weighs 0.75 ton
  - Equates to **$56/green ton delivered ($67 bdt)**
- Show Me Energy states that paying more than $60/ton makes economics very tough

Biomass Feedstock Costs ($/MMBtu)

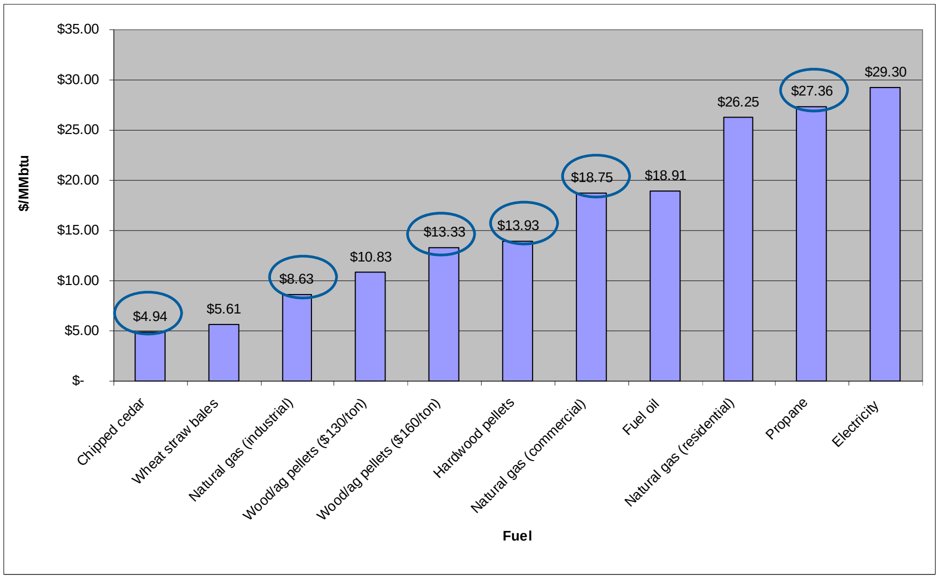


Cost Comparison of Various Fuels

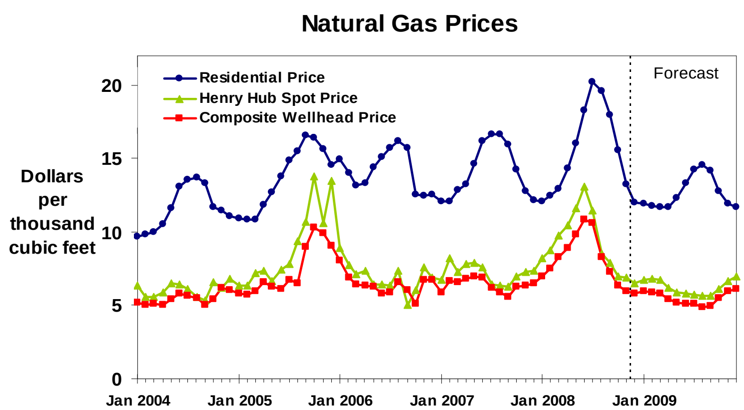
Source	Units	Cost to User ($)	Efficiency	Btu/unit	$/MMBtu
Chipped cedar	$/green ton	$ 50.00	75%	13,500,000	$ 4.94
Wheat straw bales	$/ton	$ 55.00	70%	14,000,000	$ 5.61
Natural gas (industrial)	$/therm	$ 0.69	80%	100,000	$ 8.63
Wood/ag pellets ($130/ton)	$/ton	$ 130.00	80%	15,000,000	$ 10.83
Wood/ag pellets ($160/ton)	$/ton	$ 160.00	80%	15,000,000	$ 13.33
Hardwood pellets	$/ton	$ 185.00	80%	16,600,000	$ 13.93
Natural gas (commercial)	$/therm	$ 1.50	80%	100,000	$ 18.75
Fuel oil	$/gallon	$ 2.17	85%	135,000	$ 18.91
Natural gas (residential)	$/therm	$ 2.10	80%	100,000	$ 26.25
Propane	$/gallon	$ 2.13	85%	91,600	$ 27.36
Electricity	$/kWh	$ 0.10	100%	3,413	$ 29.30

This table and chart on next page accounts for appliance efficiency, hence this is the delivered cost to the building

Various Fuel Costs ($/MMBtu)



U.S. Natural Gas Price – 5-Year History



Short-Term Energy Outlook, December 2008

- EIA projects 2009 natural gas price to average $6.25/MMBtu
- Current wholesale natural gas price (2/10/09) = $4.54/MMBtu (NYMEX March Futures Contract)

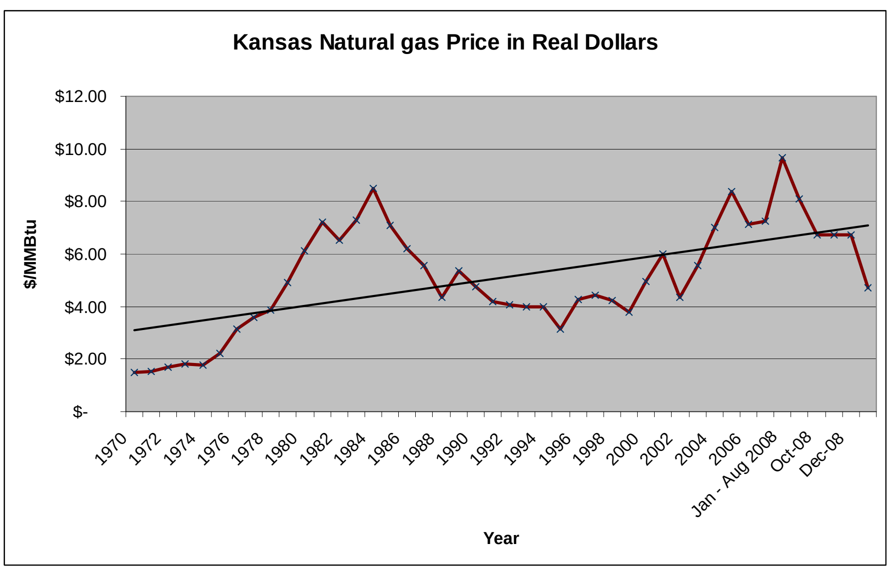
2008 Average Kansas Gas Prices

Sector / $/MMBtu	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08
Residential Price	15.29	17.14	22.41	23.81	24.90	21.82	18.73
Commercial Price	14.57	15.71	18.61	19.11	19.32	17.54	15.15
Industrial Price	9.30	9.64	10.09	11.09	10.11	8.35	6.95
Electric Power Price	10.22	10.98	11.65	10.85	8.97	6.67	N/A

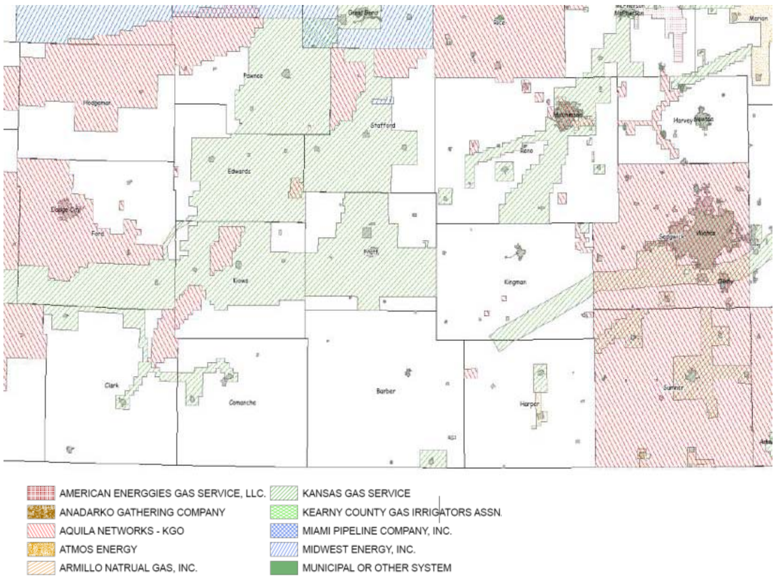
Source: U.S. DOE, EIA

- Industrial users pay the lowest cost
- Commercial and residential are best targets
- Steady downward trend since August 2008

Kansas Gas Prices – 38 Year History



Regional Gas Providers



Regional Gas Use by Customer Type

	RESIDENTIAL			COMMERCIAL			INDUSTRIAL			Total	
County	**Therms**	**# of Users**	**Average Use**	**Therms**	**# of Users**	**Average Use**	**Therms**	**# of Users**	**Average Use**	**Therms**	**# of Users**
Barber	1,040,442	1,481	702	391,788	256	1,532	0	0	0	1,432,230	1,737
Clark	576,868	777	743	181,722	133	1,366	233,991	7	33,427	992,581	917
Comanche	457,942	626	732	266,810	128	2,089	0	0	0	724,752	753
Edwards	691,173	911	758	500,976	188	2,660	142,831	16	8,927	1,334,980	1,116
Ford	6,609,854	10,616	623	4,433,399	1,071	4,139	14,841,118	189	78,524	25,884,371	11,876
Kingman	1,354,386	1,990	680	588,138	306	1,919	180,679	5	35,543	2,123,203	2,302
Kiowa	634,912	689	922	285,830	135	2,111	408,839	37	11,050	1,329,581	861
Pawnee	1,528,536	2,029	753	529,844	256	2,069	169,351	8	21,169	2,227,731	2,293
Prattt	2,386,993	3,201	746	1,498,291	487	3,074	234,771	18	13,043	4,120,055	3,706
Reno	13,864,507	20,655	671	4,683,720	1,907	2,457	23,068,579	27	854,392	41,616,806	22,588
Sedgwick	106,217,438	162,805	652	34,022,082	12,565	2,708	11,267,245	75	150,230	151,506,766	175,445
Stafford	1,032,418	1,348	766	398,222	257	1,549	84,910	9	9,434	1,515,550	1,615
Total	**136,395,468**	**207,128**		**47,780,823**	**17,690**		**50,632,314**	**391**		**234,808,605**	**225,209**

- Not every user is captured – some are on wellhead gas
- Sedgwick dominates the user base (65% of the use, 77% of the customers)
- Reno, Ford, and Sedgwick dominate industrial usage
- Sedgwick dominates commercial usage

“Pellet Equivalents” of Regional Natural Gas Use

	RESIDENTIAL			COMMERCIAL			INDUSTRIAL			Total	
County	Tons	# of Users	Average Use	Tons	# of Users	Average Use	Tons	# of Users	Average Use	Tons	# of Users
Barber	7,432	1,481	5.02	2,798	256	10.95	0	0		10,230	1,737
Clark	4,120	777	5.30	1,298	133	9.76	1,671	7	238.77	7,090	917
Comanche	3,271	626	5.23	1,906	128	14.92	0	0		5,177	753
Edwards	4,937	911	5.42	3,578	188	19.00	1,020	16	63.76	9,536	1,116
Ford	47,213	10,616	4.45	31,667	1,071	29.56	106,008	189	560.89	184,888	11,876
Kingman	9,674	1,990	4.86	4,201	306	13.71	1,291	5	253.88	15,166	2,302
Kiowa	4,535	689	6.59	2,042	135	15.08	2,920	37	78.93	9,497	861
Pawnee	10,918	2,029	5.38	3,785	256	14.78	1,210	8	151.21	15,912	2,293
Prattt	17,050	3,201	5.33	10,702	487	21.96	1,677	18	93.16	29,429	3,706
Reno	99,032	20,655	4.79	33,455	1,907	17.55	164,776	27	6,102.80	297,263	22,588
Sedgwick	758,696	162,805	4.66	243,015	12,565	19.34	80,480	75	1,073.07	1,082,191	175,445
Stafford	7,374	1,348	5.47	2,844	257	11.06	606	9	67.39	10,825	1,615
Total	**974,253**	**207,128**		**341,292**	**17,690**		**361,659**	**391**		**1,677,204**	**225,209**

Remember, total biomass resource base was about 1.8 Million bdt/yr

Counties within 25 miles of Greensburg

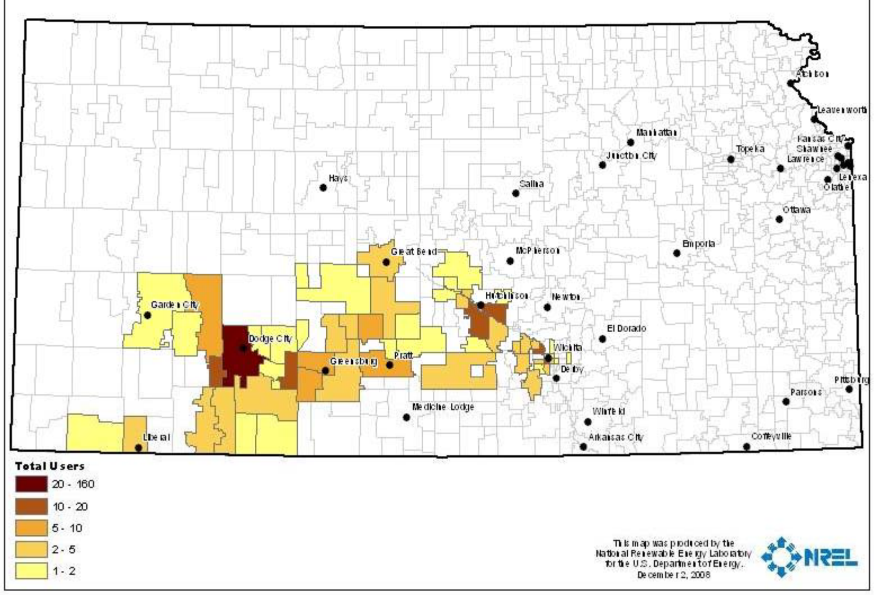
County	Residential	Commercial	Industrial	Total
Barber	7,432	2,798	N/A	10,230
Clark	4,120	1,298	1,671	7,090
Comanche	3,271	1,906	N/A	5,177
Edwards	4,937	3,578	1,020	9,536
Ford	47,213	31,667	106,008	184,888
Kiowa	4,535	2,042	2,920	9,497
Prattt	17,050	10,702	1,677	29,429
Total	88,558	53,992	113,297	255,847

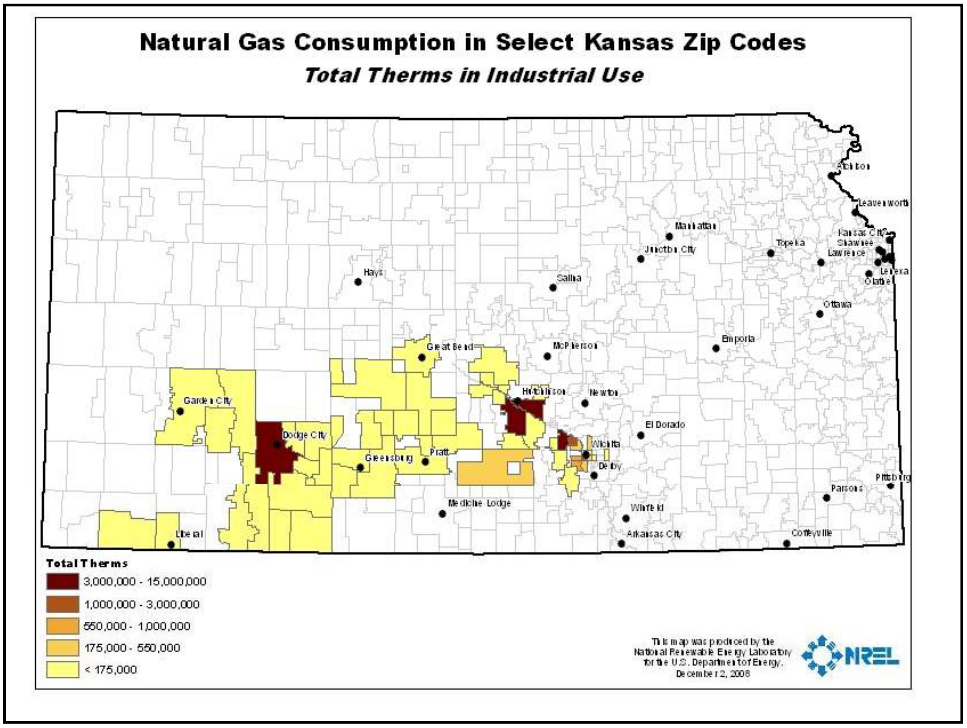
Counties within 25 miles of Pratt

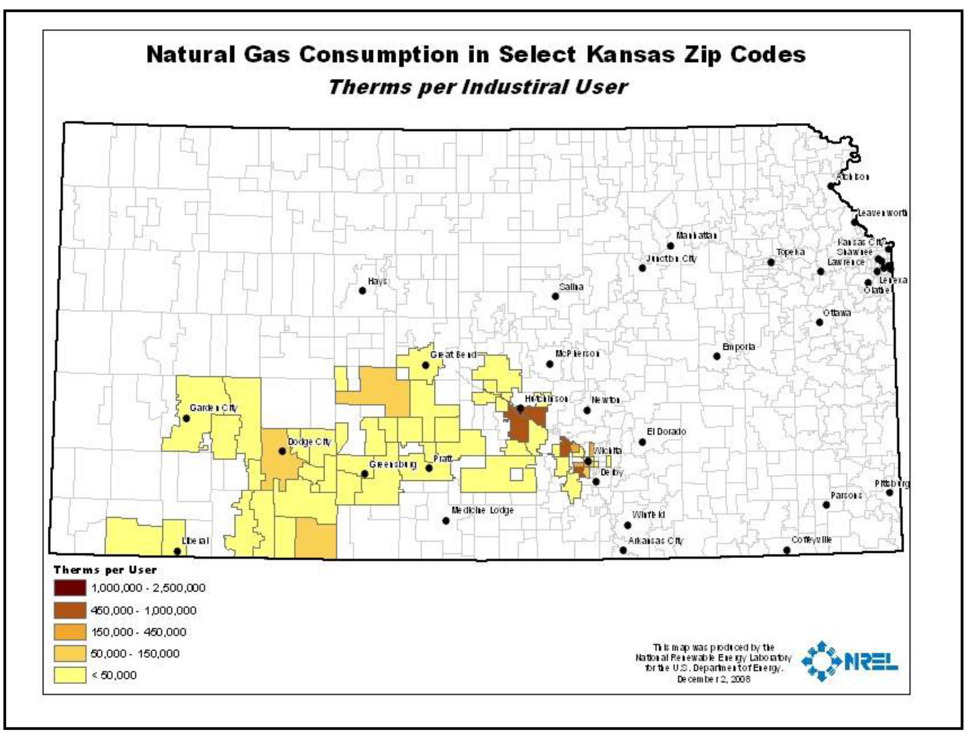
County	Residential	Commercial	Industrial	Total
Barber	7,432	2,798	N/A	
Edwards	4,937	3,578	1,020	9,536
Kingman	9,674	4,201	1,291	15,166
Kiowa	4,535	2,042	9,497	16,074
Prattt	17,050	10,702	29,429	57,181
Reno	99,032	33,455	297,263	429,750
Stafford	7,374	2,844	10,825	21,044
Total	150,035	59,621	349,325	558,981

Natural Gas Consumption in Select Kansas Zip Codes

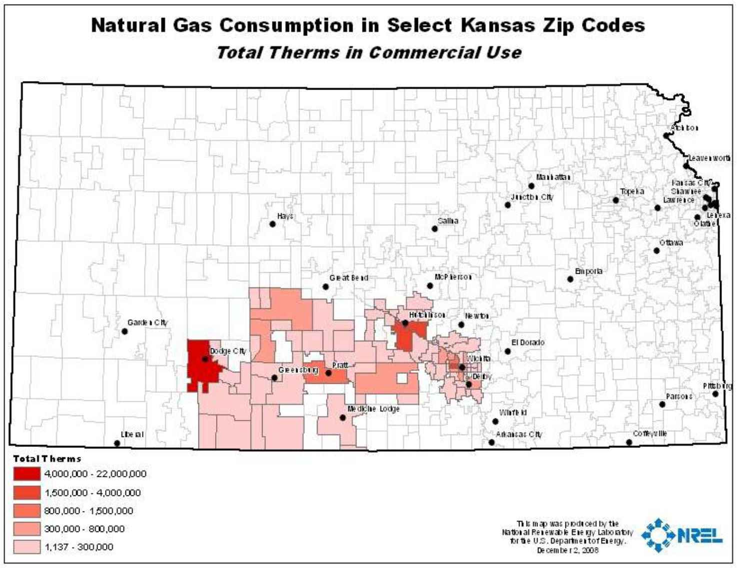
Total Industrial Users



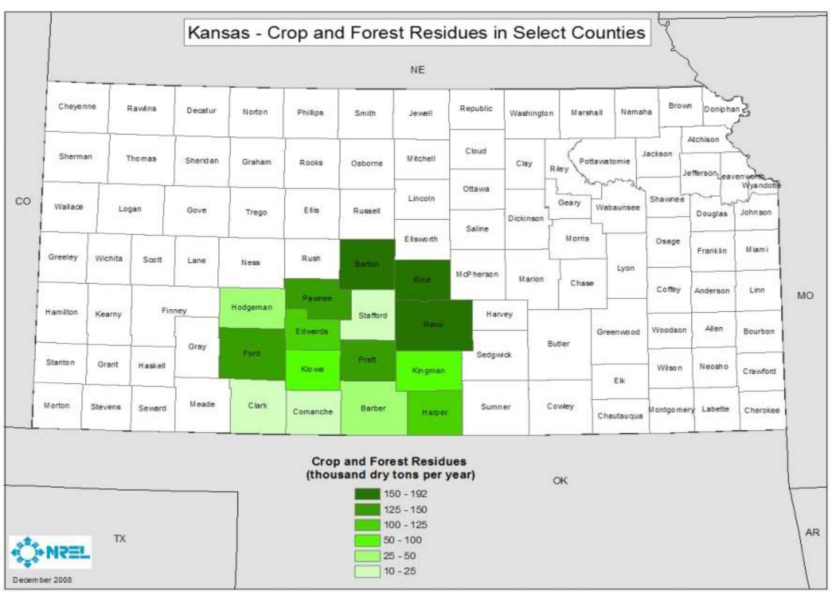

Natural Gas Consumption in Select Kansas Zip Codes
Total Therms in Industrial Use
Total Therms
3,000,000 - 15,000,000
1,000,000 - 3,000,000
550,000 - 1,000,000
175,000 - 550,000
< 175,000
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy. December 2, 2008
NREL


Natural Gas Consumption in Select Kansas Zip Codes
Therms per Industiral User
Therms per User
1,000,000 - 2,500,000
450,000 - 1,000,000
150,000 - 450,000
50,000 - 150,000
< 50,000
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy. December 2, 2008
NREL

Same Patterns for Commercial Sector



Residue Distribution



Competitor Analysis – Show Me Energy Co-op (SMEC), Centerview, MO

- First large-scale plant of its kind that we know of
- About 240 miles from Wichita
- Producing 30k tons/yr now; capacity of 60k
- 50-50 blend of ag (straw, old hay) and wood
- 7,000 Btu/lb, 1.4 lbs alkali/MMBtu and 9% ash [Pellet Fuels Institute (PFI) utility grade pellet]
- Selling for $130 FOB plant ($9/MMBtu)
- Also selling un-pelletized biomass
- Appliances that use these pellets need to handle high ash and slagging
- Target market appears to be large coal-fired utilities

Ozark Hardwood Products, Seymour, MO

- Closest hardwood (super-premium) supplier to the region (~400 miles to Greensburg, 300 to Wichita)
- 8,000 Btu/lb and < .5% ash, low alkalis
- $130 FOB plant, $55 bulk freight to Greensburg ($10.80/MMbtu)
- Only 60 cents more than wood-ag pellets at $160/ton ($10.20/MMBtu)
- Providing customers with packaged furnaces in a shipping container, with multi-year supply contract
- Pellets can be burned in any appliance on the market

Prairie Fire Bioenergy Co-op, Healy, KS

- Started Fall 2008
- 279 miles to Wichita, 137 to Greensburg
- 85% wood, 15% ag residues
- Make standard grade pellets (< 3% ash)
- Selling bagged pellets for now, trying to develop bulk markets (price is $130/ton FOB plant)
- 26k tons/yr production
  - on ag residues capacity would be 50k tons/yr
- Initial plan was to sell pellets to SMEC for bulk sales to Europe (then recession hit)
- Approached local ethanol producer and proposed:
  - Prairie Fire would finance an AES gasifier (Uniconfort) and sell the ethanol plant thermal energy at $6.25/MMBtu when the plant was then paying $8/MMbtu. Plant was not interested.

Abengoa Ethanol Plant, Hugoton, KS

- 490,000 "as is" tons/year biomass (12 million gals/yr ethanol and replaces natural gas for plant)
  - Focused on irrigated wheat, irrigated corn stover, milo stubble, switchgrass, and CRP lands
  - Not likely to pull from Greensburg area
  - 200,000 – 250,000 acres of land
- 32 million bushels of grain for 88 million gal/yr ethanol plant
- Will require 10%-12% of biomass within 50 mile radius of Hugoton
- Complex fuel procurement contract
  - Nutrient obligation (phosphorus and alkalis back from plant, coupon for nitrogen)
  - Abengoa controls (or subcontracts) all aspects of biomass collection
  - Abengoa handles biomass loading, hauling, and storage

First plant in Spain

Proposed Abengoa Payments

- Contract signing bonus ($1/acre)
- Annual reservation payment ($0.50/acre)
  - Paid to supplier every year even if Abengoa does not need the biomass from that supplier
- Base payment
  - Abengoa pays a single negotiated price to every supplier in its network
  - Abengoa equipment and labor collect the biomass (or use contract harvester)
- Revenue sharing payment (optional)
  - Producer accepts lower base payment for some biomass and takes share of ethanol plant profit

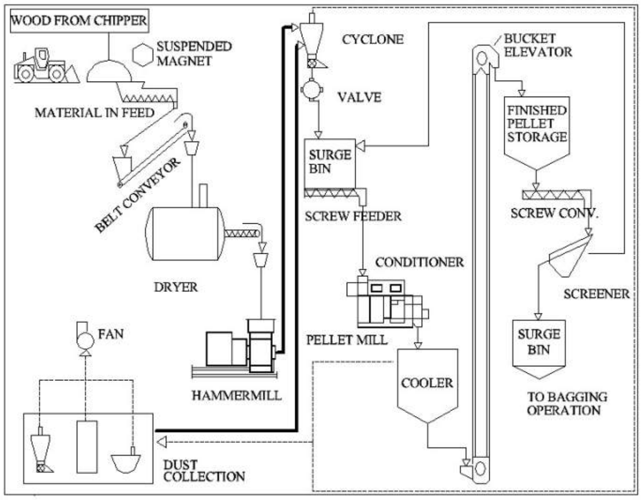
Potential Local Customers

- National Gypsum Plant, Medicine Lodge, KS
  - See next slide
- Orion Ethanol Plant, Pratt, KS (maybe someday?)
- Veterans Administration (VA) Hospital in Wichita, KS
  - Federal agencies must meet requirements for renewable energy under Executive Order 13423 and Energy Independence and Security Act of 2007
  - VA conducting nation-wide screening for biomass combined heat and power (CHP)
  - Supposed to be providing facility data to NREL
- Many others listed in Appendix in report

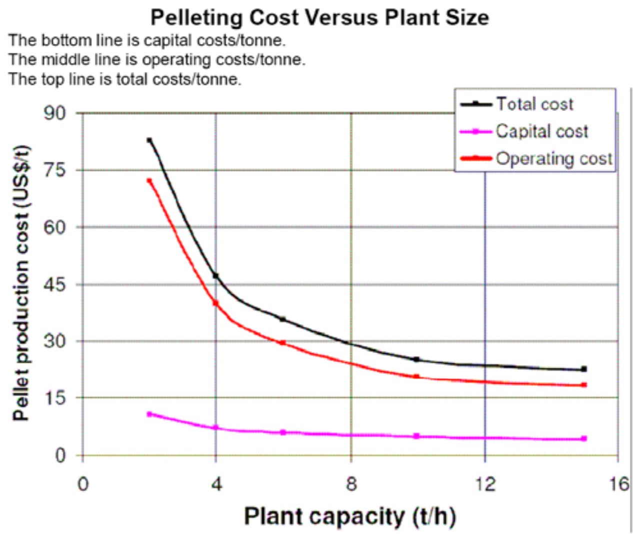
National Gypsum, Medicine Lodge

- Located about 30 miles from Pratt, 60 from Greensburg
- Consumes about 900,000 MMBtu natural gas per year
  - Direct-fired in furnace for drying gypsum and product
- Gas price: New York Mercantile Exchange plus $0.45 for delivery
- Interested in biofuels, but must compete with gas
- Interested in storable product as they "do not want yard to look like a paper mill"
- Replacing 75% of thermal load with pellets equates to about 45,000 tons/year
- Are interested in conducting detailed cost-benefit analysis

Illustrative Pellet Plant Layout



Manufacturing Costs per Tonne (Exclusive of Feedstock Cost)



- Trend in North America and Europe is towards bigger and bigger plants to maximize economies of scale and produce at low costs

Source: Campbell

Pellet Business Success Factors

- Price
  - Must compete with fossil fuels and other renewable options
  - Feedstock cost is number one driver
  - Ag pellets produce a lot of ash and are high in alkalis, therefore consumers will expect price concession to offset the inconvenience factor and higher labor
- Quality
  - Poor pellet quality can kill a company's reputation
  - Some ag materials do not bind as well as wood, thereby producing a lot of fines – hence wood blends are common
  - Consistency is key – end users want to know what they are getting

Summary

- More than enough feedstock in local area
- Pratt and Greensburg about equal in terms of feedstock
  - But least-cost delivery point of cedar is most important
- Pratt is closer to Medicine Lodge, Orion ethanol plant, and Wichita
- Greensburg closer to Dodge City, KS
- Pellets cannot compete with industrial gas at these prices
  - Can compete with commercial gas (for now), propane, and electricity
  - End-users will expect price concession for using high ash, high alkali fuels
- Cedar chips and unprocessed straw bales are least cost biomass resource in the area
  - Sell cedar chips to Medicine Lodge?

Summary (cont.)

- The fact that end-users will need to buy a new boiler or furnace is a barrier to market development
- Consider third party financing model (pellet plant installs the boiler and sells Btus to the end user)
  - Will be tough to finance this arrangement in today's market
- Related to plant economics, bigger plants will out-compete smaller plants in terms of price
  - as long as sufficient feedstock can be obtained at same delivery price

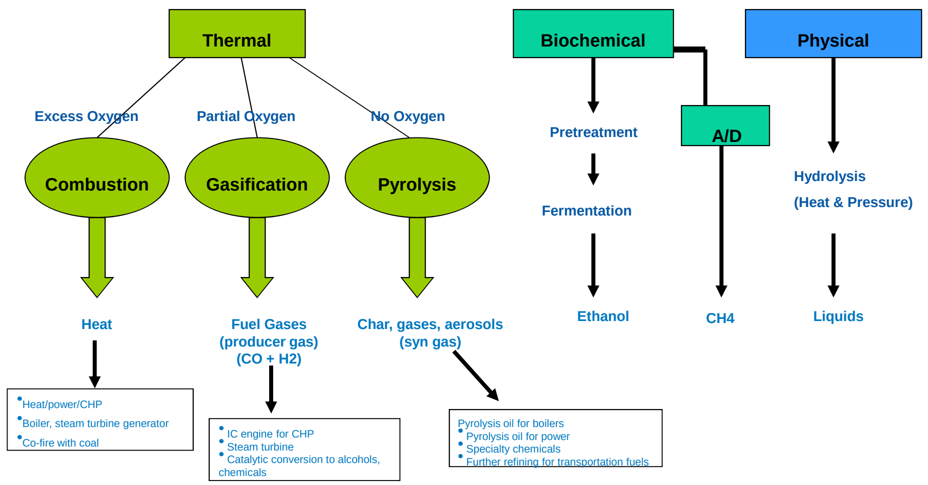
Summary (cont.)

- Considerable market development efforts are still needed
  - There are not a lot of incentives for users to switch
  - There are not a lot of incentives to be the first plant owner (as Campbell describes it, "the advantage of being second")
- Carbon tax or national Renewable Portfolio Standard may change the game, so keep monitoring the process
  - But what is the carbon footprint of this entire process???
- National Gypsum plant should conduct detailed economic analysis of converting to pellets, chips, or even straw

Suggestions for Next Steps

- Test local corn stover, cobs, and sorghum residues at lab
- Refine collection costs and quantity for cedar
- Talk to local producers (irrigated corn, sorghum) and develop supply network – identify as many large scale producers as close to the plant as possible
- Develop test blend of cedar/stover/sorghum pellets
- Test fire the pellets in potential appliances and see how they work
- Continue market development efforts with large commercial and industrial customers
  - National Gypsum, VA Hospital, others
- Monitor local and national market conditions
- NREL to complete draft report

Biomass Energy Pathways



Technical Issues - Combustion

- 20% - 30% efficient
- Mineral management issues (slagging and fouling of the boiler)
- Emissions: NO_x, CO, particulate
- Wide range of fuel types
- Multiple vendors
- Equipment warranties
- Tried and true; trusted by lenders
- Needs water

Biomass Gasification

- Pre-commercial, early demo
- Potentially better suited to small scales
- More efficient than combustion, 30%- 40%
- Manages mineral matter
- Fuel gas ($CO + H_2 + CH_4$) can be used in IC engines, gas turbines, steam turbines or to make liquid fuels
- Installed cost of $3,500 and up per kW
- Levelized Cost of Energy: $0.15 - $0.20⁺

Pellet Boiler for Thermal Energy

- Harney Hospital, Burns, OR
  - 25 bed facility
- KÖB – Austrian technology shipped in container and connected in 2 days
- Commercial technology
- $250,000 cost, saving $37,000 per year
- 750 sq ft footprint

Biopower Summary

- 2006 capacity – 10.5 GWe
  - 5 GW pulp and paper
  - 2 GW dedicated biomass
  - 3 GW MSW and landfill gas
  - 0.5 GW cofiring
- Cost – \$0.06 – \$0.20 USD/kWh
- Requires production tax credit to compete in wholesale markets
  - Half the tax credit that wind gets
- High capacity factor, baseload
- Usually requires significant water
- CO_2 neutral

Close-coupled Gasification

- North Country Hospital, VT
- Chiptec C-Series close-coupled gasifier
  - (gas is combusted to make steam for a turbine)
- Commercial technology, hundreds of systems
- 265 kW CHP system
- 500 Hp, 300 PSI Hurst boiler
- Saving \$250,000/year

D.11 Assessment of Biomass Pelletization Options for Greensburg, Kansas – Executive Summary

Scott Haase
National Renewable Energy Laboratory

A national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy

National Renewable Energy Laboratory

Innovation for Our Energy Future

Assessment of Biomass Pelletization Options for Greensburg, Kansas

Executive Summary

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Technical Report
NREL/TP-7A2-45843
November 2009

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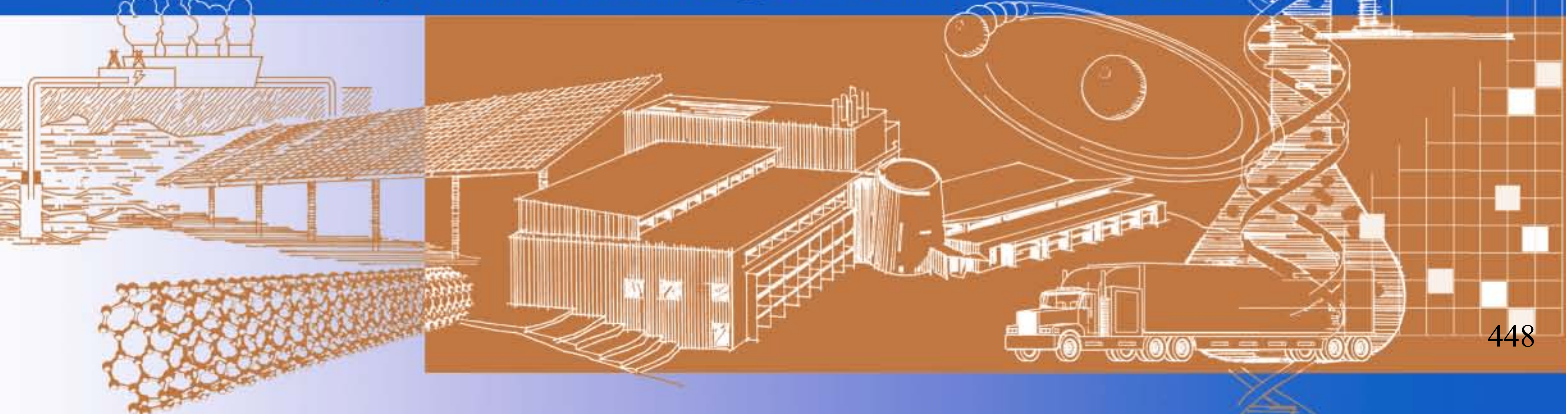

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Prepared under Task No. IDKS.1070

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Alexander Dane

Project Name: Assessment of Biomass Pelletization Options for Greensburg, Kansas: Executive Summary

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- Terry Studer, Local Agricultural Producer.

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Executive Summary

In May 2007, the town of Greensburg, Kansas, was struck by a large tornado that destroyed more than 90% of the buildings and infrastructure of the town. After this devastating event, the citizens of Greensburg decided to rebuild their town in a green manner, incorporating the most efficient energy technologies possible in the reconstruction effort. The U.S. Department of Energy, through the National Renewable Energy Laboratory (NREL), has been providing technical assistance to Greensburg to help facilitate the various efforts. As part of this support, NREL conducted an assessment of potential opportunities to develop a biomass pelletization or briquetting plant in the region.

Major activities conducted for this assessment include the following:

- Detailed analysis of the biomass resource base in the region, including quantity, physical and chemical properties, availability, cost, and collection potential
- Assessment of demand for thermal energy in the region, and opportunities for biomass to be utilized to meet some of that demand
- Overview of the pellet manufacturing process, including equipment needs, capital costs, and manufacturing costs
- Overview of briquette and bripell manufacturing technologies and costs
- Discussion of end-use conversion technologies
- Conclusions and recommendations for next steps.

Biomass Resource Assessment

Biomass Quantity and Geographic Distribution. NREL conducted a detailed, county-level assessment of the biomass residues found in the region. The primary agricultural biomass types located in the region include corn stover, corn cobs, sorghum residue, and wheat straw. There is also significant potential to collect woody biomass in the form of eastern red cedar. Eastern red cedar is considered an invasive species, and it is spreading rapidly from Oklahoma into southwestern Kansas. Cedar trees are being aggressively cut and removed to prevent its continued spread into agricultural lands.

Counties were included in the analysis if all or most of the county boundary is located within a 50-mile radius of either Pratt or Greensburg, Kansas. Using data available from the U.S. Department of Agriculture National Agricultural Statistics Service (NASS), NREL estimated the quantities of residues that are produced in the region. NREL used a 10-year average of values to account for potential year-to-year fluctuations in market conditions, weather patterns, and harvest. Based on total residue produced, NREL then used standard factors to estimate the amount of biomass that could safely be removed from agricultural lands while still maintaining nutrient cycling, soil health, and erosion mitigation. We estimated the quantity of eastern red cedar available through interviews with a local cedar clearing company. The full methodology is documented in Appendix A of this report.

Table ES-1 shows the total residues available in the study area, by county. A total of 1.7 million bone dry tons per year (bdt/yr) are available within counties that intersect 50 miles of Pratt and Greensburg. The value under "other forestry removals" for Pratt County is an estimate of the quantity of eastern red cedar available in the area. Even though this material is collected from many counties in the region, this quantity has been assigned to Pratt County because it is the location of the contractor's business. It should also be noted that the values for corn are based only on residues available from irrigated acres. We found that non-irrigated corn is in a net-deficit situation, meaning that more residue should be left on the land than is actually being produced.

Table ES-1. Summary of Biomass Residues

	Residues Available (bdt/yr)									
County	**Wheat**	**Corn**	**Sorghum**	**Soybean**	**Sunflower**	**Cotton**	**Logging Residues**	**Other Forestry Removals**	**Corn Cobs**	**Total**
Barber	25,283	407	4,004	1,337	46	210	161	2,818	623	34,888
Barton	74,604	17,556	47,399	14,320	222	-	22		14,760	168,882
Clark	469		9,681	345	-	-	-		218	10,713
Comanche	3,835	285	5,357	627	-	-	-		450	10,554
Edwards	31,955	39,921	18,599	21,961	60	-	-		31,913	144,409
Ford	55,368	22,632	53,883	10,214	136	-	-		21,533	163,765
Harper	96,815	146	9,270	1,821	65	436	0		135	108,687
Hodgeman	21,536	2,228	18,130	1,287	-	-	-		4,200	47,380
Kingman	78,586	5,270	8,869	6,458	185	-	-		3,810	103,177
Kiowa	17,281	15,562	12,205	12,255	24	-	-		15,113	72,438
Pawnee	59,127	21,710	35,327	16,494	52	-	-		18,915	151,626
Pratt	58,679	38,472	19,270	17,711	377	1,122		12,500	33,533	181,663
Reno	89,693	13,495	51,240	22,829	1,253	-	15		13,118	191,642
Rice	111,254	14,194	50,816	15,130	931	-	24		8,190	200,539
Stafford	35,258	18,182	20,366	14,845	85	-	-		31,935	120,670
Total	**759,742**	**210,058**	**364,416**	**157,632**	**3,435**	**1,768**	**222**	**15,318**	**198,443**	**1,711,034**

Figure ES-1 shows the geographic distribution of the residues in the study area. Notice that, in general, greater quantities of residues are produced in the eastern counties of the region.

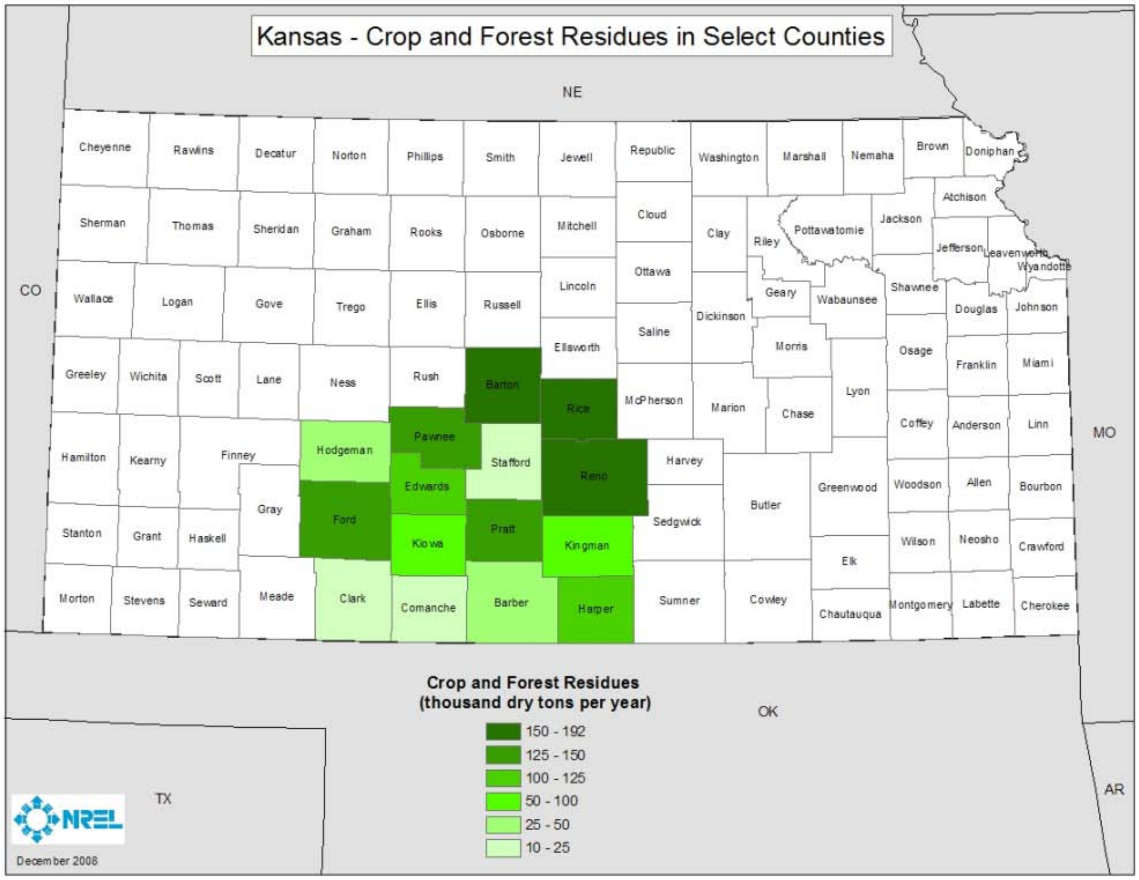

Figure ES-1. Biomass residue distribution

Looking in greater detail at the production of agricultural residues, we present in Table ES-2 the yields of biomass per acre of land harvested. The values for corn are only from irrigated acres. The table indicates that irrigated sorghum and irrigated corn will yield the greatest amount of biomass per acre. Thus, if one is interested in collecting agricultural residues, these two feedstocks should be considered as the top priority, as fewer acres will be needed to collect the most material.

Table ES-2. Yields of Biomass per Acre of Crop Land (bdt/acre/yr)

County	Wheat (bdt/acre)			Sorghum Residues (bdt/acre)			Corn (bdt/acre)
	Wheat Irrigated	Wheat Non-irrigated	Wheat Total	Sorghum Irrigated	Sorghum Non-irrigated	Sorghum Total	Corn Stover and Cobs
Barber	0.52	0.22	0.22			0.50	1.24
Barton	0.67	0.46	0.46	1.35	0.80	0.86	1.64
Clark	0.27	-	0.01	1.22	0.70	0.65	0.75
Comanche	0.44	0.05	0.06	1.23	0.37	0.55	1.23
Edwards	0.70	0.27	0.33	1.13	0.60	0.71	1.69
Ford	0.57	0.31	0.33	1.28	0.71	0.80	1.54
Harper	0.61	0.44	0.44			0.57	1.56
Hodgeman	0.64	0.17	0.21	1.09	0.64	0.69	1.15
Kingman	0.69	0.40	0.41	1.20	0.54	0.59	1.79
Kiowa	0.47	0.22	0.25	1.27	0.63	0.73	1.52
Pawnee	0.74	0.42	0.45	1.29	0.73	0.83	1.61
Pratt	0.58	0.39	0.40	1.25	0.64	0.70	1.61
Reno	0.68	0.37	0.38	1.17	0.67	0.71	1.52
Rice	0.57	0.75	0.75	1.07	0.63	0.85	2.05
Stafford	0.56	0.23	0.26	1.24	0.69	0.75	1.18
Average	**0.51**	**0.26**	**0.28**	**1.05**	**0.52**	**0.58**	**1.47**

Biomass Physical and Chemical Properties. Table ES-3 shows the results of lab tests for some of the feedstocks in the region. The column labeled SMEC pellets shows the results of tests performed on a 50-50 blend of wood and agricultural residues made by Show Me Energy Cooperative (SMEC) of Centerview, Missouri. These pellets have moderate Btu value, high percentage of ash, and high alkalis. Most pellet-burning appliances are designed to handle low-ash (< 1%) fuels and low-alkali fuels. Values higher than 0.4 pounds of alkali per million British thermal units (lb/Mbtu) are likely to cause slagging or clinker formation during the combustion process. Pellets made from wood and agricultural residues in Greensburg would exhibit similar characteristics if similar blend ratios are used. In general, the SMEC pellets are better suited for use in large-scale utility plants (mixed with coal) or in large industrial- or commercial-scale biomass combustors designed to handle high-ash, high-alkali fuels. Appendix B contains the detailed lab results of the analysis of these samples, and of samples of corn stover, corn cobs, and sorghum residue.

Potential end users of biomass pellets in the region would likely want a price concession on the cost of the product in order to offset the higher operations and maintenance costs associated with using a high-ash, high-alkali fuel.

Table ES-3. Biomass Physical and Chemical Properties

Value	Wheat Straw	Freshly Cut Cedar	Seasoned Cedar	SMEC Pellets
Btu content as received HHV (Btu/lb)	7,125	8,143	8,056	7,059
Btu content bone dry (Btu/lb)	7,709	8,827	8,976	7,680
Moisture content as received (%)	7.57	7.75	10.25	8.09
Percentage Ash (%)	7.83	1.63	0.88	9.04
Lb Alkali/Mbtu	1.3	0.08	0.05	1.44
Lb ash/Mbtu	10.99	2.00	1.09	12.81
Potassium in ash as K2O (%)	11.4	3.25	4.55	10.8

The values for cedar shown in Table ES-3 indicate that this material would make an excellent feedstock for a biomass system. A product made of only cedar, or mostly cedar, is going to have much better combustion properties than a 50-50 blend of agricultural residues and cedar. For this reason, entrepreneurs wishing to develop a plant in the region may want to use either 100% cedar or a small blend percentage of agricultural residues. Test batches of various blend percentages would need to be made in order to test for ash content and alkali values before any full-scale production begins. The size of any potential pellet enterprise may be limited by the quantity of cedar that can economically be collected in the region.

Biomass Cost. Biomass collection cost is one of the major factors influencing the final cost of pellets. One of the challenges of using agricultural residues for feedstock is that the resource is dispersed on the land and relatively expensive to collect. Remember, too, that biomass pellets are competing against fossil fuels–primarily natural gas and propane. In recent months, the wholesale price of natural gas has fallen from \$14/Mbtu to less than \$4/Mbtu.

Figure ES-2 shows the cost of biomass in \$/Mbtu versus various costs to collect and deliver a ton of agricultural residues. Based on results of this and other studies referenced herein, we estimate that biomass collection costs will be in the range of \$55-\$60 per field-dried ton for agricultural residues. Note that at \$60 per ton, the fuel cost alone is equivalent to \$4.29/Mbtu. When pellet manufacturing costs (labor, energy, packaging, debt, transportation) are added to this, it is clear that pellets will have a difficult time competing with fossil fuels at today's prices.

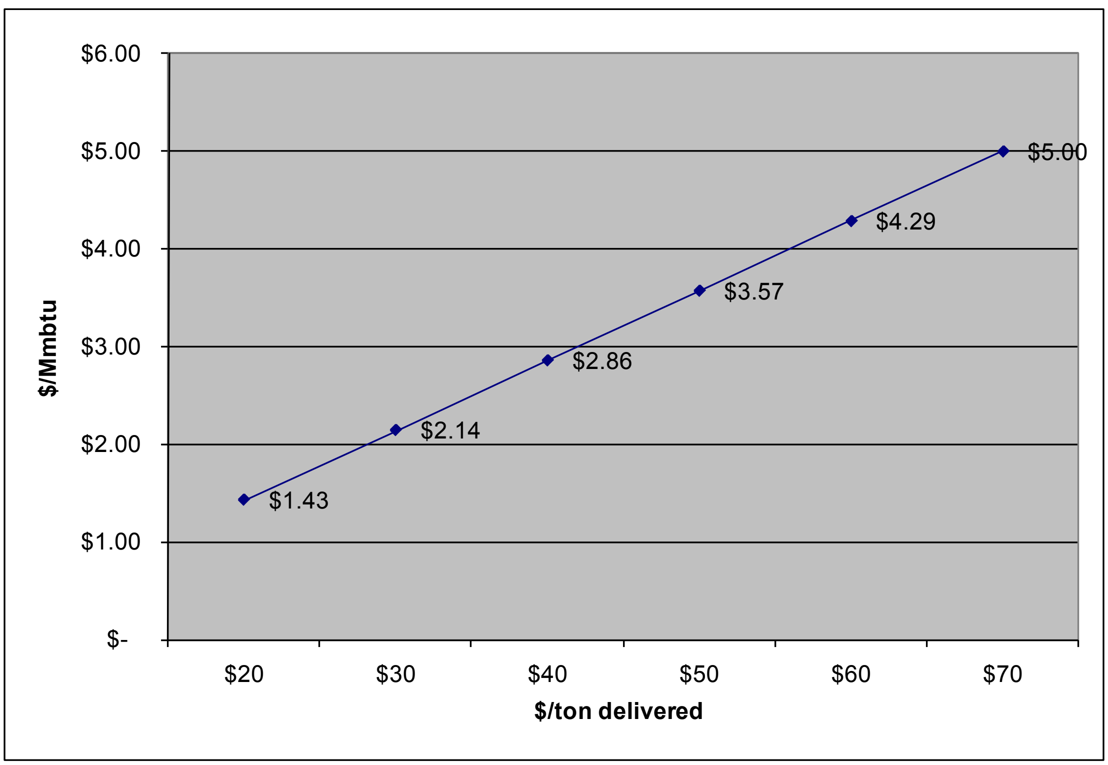

Figure ES-2. Fuel costs of agricultural residues (\$/Mbtu versus \$/delivered ton)

The delivered cost of cedar biomass is likely to be somewhat lower than that of agricultural residues. We estimate that cedar can be delivered to a regional pellet manufacturing plant for about \$35/green ton. Assuming 8,800 Btu per dry pound and 40% moisture, this equates to

$3.31/Mbtu. Cedar is an important feedstock in the region, as it is likely to be the lowest cost resource; at the same time it has the best physical and chemical qualities of all the regional biomass sources.

Regional Demand for Thermal Energy and Competing Fuel Costs

Comparison of Fuel Prices. Table ES-4 shows the delivered costs of energy from various fuels used in the region. The delivered cost of energy takes into account appliance efficiency and thus represents the cost to deliver a therm of useful energy to the building space. The natural gas prices used in the table are based on statewide averages for Kansas for the months of April through December 2008. Although the natural gas prices are based on average values for the period, note that the most recent prices for November and December 2008 were considerably lower than the averages. So while the commercial cost per therm is listed as $1.57 in table ES-4, the value for December 2008 was $1.00 per therm, which would make the delivered cost of energy $12.00/Mbtu as compared to the $19.63 shown in Table ES-4.

Table ES-4. Delivered Cost of Thermal Energy for Various Fuels ($/Mbtu)

Source	Units	Cost to User ($)	Efficiency (%)	Btu/unit	$/Mbtu
Chipped Cedar	$/green ton	50.00	75	13,200,000	5.05
Wheat straw bales	$/ton	55.00	70	14,000,000	5.61
Natural gas (industrial)	$/therm	0.69	80	100,000	8.63
Wood/ag pellets ($130/ton)	$/ton	130.00	80	15,000,000	10.83
Wood/ag pellets ($160/ton)	$/ton	160.00	80	15,000,000	13.33
Hardwood pellets	$/ton	185.00	80	16,600,000	13.93
Natural gas (commercial)	$/therm	1.50	80	100,000	18.75
Fuel oil	$/gallon	2.17	85	135,000	18.91
Natural gas (residential)	$/therm	2.10	80	100,000	26.25
Propane	$/gallon	2.13	85	91,600	27.36
Electricity	$/kWh	0.10	100	3,413	29.30

When assessing the market for pellets, it is important to remember that fossil fuel prices fluctuate considerably, and while prices are low, end users may not be as interested in alternative fuels as they would be when prices are high. One of the selling points of biomass should be that biomass prices typically remain stable and seldom exhibit the wild price swings evident with fossil fuels.

Chipped cedar at $50 per ton has the lowest delivered cost, followed by straw bales. However, the use of these fuels will require additional on-site labor and higher up-front capital costs when compared with systems that burn pellets or other densified fuels. Notice that wood/ag pellets at $130 per ton are about $0.67 less per Mbtu than the cost of energy at the average industrial rate for gas in Kansas. It is difficult to compete with natural gas if your fuel is just slightly less expensive yet takes more labor and maintenance and requires an up-front purchase of a new appliance. Ag pellets at $130 per ton compare nicely, however, with hardwood pellets at $185 per ton, fuel oil at $2.17 per gallon, propane at $2.13 per gallon, and electrical resistance heat at $0.10 per kilowatt-hour (kWh). Ag pellets also compare well with commercial natural gas rates of $19.63/Mbtu. Ag pellets at $160 per ton compare favorably with fuel oil, commercial and residential gas, propane, and electricity. Note that it may be a challenge for a pellet plant to deliver wood/ag pellets to its customers at $130 per ton, even when using bulk shipments instead of plastic bags. A cost of $160 per ton for bulk pellets delivered to a regional customer may be more likely.

Table ES-5 shows the average natural gas rates in Kansas by customer type. Data are shown through October 2008. It is likely that in the near term these rates will show a continued downward trend. The value for "electric power price" is the rate paid for gas used to generate electricity. The Energy Information Administration reports the data in terms of dollars per thousand cubic feet ($/Mcf). We have reported these values in $/Mbtu to be consistent with the other units used in this report.

Table ES-5. Average 2008 Monthly Natural Gas Prices in Kansas, by Customer Type ($/Mbtu)

Sector	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Average
Residential	15.29	17.14	22.41	23.81	24.90	21.82	18.73	12.71	10.41	18.58
Commercial	14.57	15.71	18.61	19.11	19.32	17.54	15.15	11.64	10.06	15.75
Industrial	9.30	9.64	10.09	11.09	10.11	8.35	6.95	7.84	9.25	9.18
Electric Power	10.22	10.98	11.65	10.85	8.97	6.67	4.50	4.88		8.59

Figure ES-3 shows historic wholesale prices of Kansas natural gas, adjusted to 2008 dollars. Prices have experienced significant volatility over the 36-year period. From the early1990s until about 2000, prices were around or below $4/Mbtu and relatively stable. Since the year 2000, prices had been on a steady upward trend until the fall of 2008. With the recent economic downturn, prices have fallen significantly. On January 22, 2009, the Henry Hub natural gas prices closed at $4.72/Mbtu. Although prices have fallen precipitously over the last few months, the long-term trend line is still upward, at least for now.

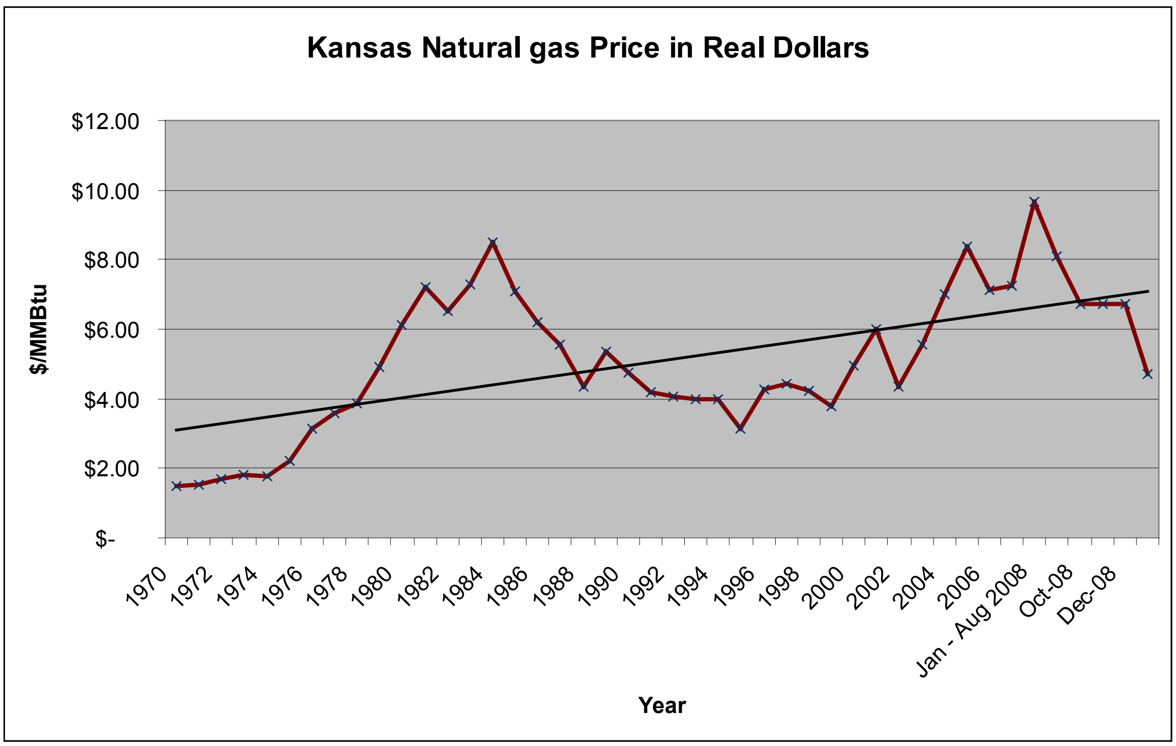

Figure ES-3. Industrial customer natural gas prices (1970-January 2009)

Regional Demand for Natural Gas. NREL contacted regional natural gas providers to request aggregate data on natural gas sales by zip code or town/city place name. NREL staff then aggregated these data to the county level. Table ES-6 shows the estimated regional demand for thermal energy based on natural gas consumption. These numbers do not account for customers heating with propane, fuel oil, or other sources such as electricity, corn, or wood pellets, or customers on well-head gas. Overall, nearly 235 million therms of natural gas are consumed each year by more than 225,000 customers in the study area. The largest county in terms of both consumption and users is Sedgwick, which contains the city of Wichita. Reno and Ford counties also consume significant quantities of natural gas. While it is clear that it is not possible for pellets to replace 100% of regional natural gas use, the annual consumption of natural gas in the region is equivalent to approximately 1.6 million tons of pellets, assuming 7,000 Btu/lb for the pellets. This is tied very closely to the potential supply in the region of 1.8 million bdt/yr.

Table ES-6. Regional Demand for Natural Gas by Customer Type

	RESIDENTIAL			COMMERCIAL			INDUSTRIAL			Total	
County	Therms	# of Users	Average Use	Therms	# of Users	Average Use	Therms	# of Users	Average Use	Therms	# of Users
Barber	1,040,442	1,481	702	391,788	256	1,532	0	0	0	1,432,230	1,737
Clark	576,868	777	743	181,722	133	1,366	233,991	7	33,427	992,581	917
Comanche	457,942	626	732	266,810	128	2,089	0	0	0	724,752	753
Edwards	691,173	911	758	500,976	188	2,660	142,831	16	8,927	1,334,980	1,116
Ford	6,609,854	10,616	623	4,433,399	1,071	4,139	14,841,118	189	78,524	25,884,371	11,876
Kingman	1,354,386	1,990	680	588,138	306	1,919	180,679	5	35,543	2,123,203	2,302
Kiowa	634,912	689	922	285,830	135	2,111	408,839	37	11,050	1,329,581	861
Pawnee	1,528,536	2,029	753	529,844	256	2,069	169,351	8	21,169	2,227,731	2,293
Prattt	2,386,993	3,201	746	1,498,291	487	3,074	234,771	18	13,043	4,120,055	3,706
Reno	13,864,507	20,655	671	4,683,720	1,907	2,457	23,068,579	27	854,392	41,616,806	22,588
Sedgwick	106,217,438	162,805	652	34,022,082	12,565	2,708	11,267,245	75	150,230	151,506,766	175,445
Stafford	1,032,418	1,348	766	398,222	257	1,549	84,910	9	9,434	1,515,550	1,615
Total	**136,395,468**	**207,128**		**47,780,823**	**17,690**		**50,632,314**	**391**		**234,808,605**	**225,209**

Adding the pellet potential across the commercial and industrial sectors yields 700,000 tons per year maximum potential. Assuming pellets can capture 5% of this market, we get a total of about 35,000 tons per year local potential in these sectors. This is not to suggest that the market in the area is limited to 35,000 tons. It may be possible to identify several larger customers that alone could consume more than 35,000 tons at a single facility. These large potential users should be contacted directly to discuss their possible interest in biomass pellets. It is also possible to develop markets outside of the local area, either by truck or rail.

Entrepreneurs interested in starting a pellet facility should be prepared to spend significant amounts of time educating potential end users and developing the market before constructing any facility. One of the biggest challenges associated with building a facility to make pellets in the region is that there are no existing customers beyond perhaps some residential or farm users of pellet or corn appliances. This is the proverbial "chicken and egg" problem—end users will only be willing to invest in conversion technologies to burn pellets if there is a reliable, affordable, high-quality product available, and the builders of a pellet mill must have a reliable, credit-worthy customer base to ensure that the product they make can be sold. Under present market conditions, there are few compelling reasons for potential end-users to be early adopter adapter.

Possible Local Commercial Customers. A successful biomass fuel production facility would need to develop off-take contracts with customers in order to obtain financing. Two industrial plants in the area, Orion Ethanol in Pratt and National Gypsum in Medicine Lodge, may be potential customers. The Pratt ethanol plant is not operating at this writing but presumably could be reactivated when more favorable business conditions return. There are many other potential customers in Dodge City and Wichita that could be identified and contacted.

As an example of a potential customer, the National Gypsum drywall manufacturing plant in Medicine Lodge could utilize biomass fuel. The plant presently consumes about 900,000 Mbtu per year of natural gas in its dryers. Offsetting 75% of this load would require on the order of 45,000 tons of biomass pellets (or 50,000 tons of 25% moisture content cedar chips) per year. As of February 2009, National Gypsum is interested in exploring the economics of switching from gas to biomass.

National Gypsum currently purchases natural gas for the NYMEX price, plus about 45 cents for delivery. Biomass costs must compete with those of natural gas. National Gypsum's delivered cost of gas is presently about $5.00/Mbtu, although this price fluctuates daily. We do not believe that biomass pellets can be delivered to National Gypsum for $5per million Btu. If a ton of biomass pellets has 15 Mbtu, then the delivered cost would need to be $75 per ton to meet $5/Mbtu gas. The only biomass feedstock that can come close to meeting this cost at present is cedar chips.

It is interesting to consider emissions of carbon dioxide. Consumption of 675,000 Mbtu/yr of natural gas (75% of National Gypsum's estimated use) emits 39,500 tons of CO_2 per year. Since biomass is considered CO_2 neutral by the U.N. International Panel on Climate Change, conversion to biomass could potentially free up carbon credits for National Gypsum under a cap and trade system. Some of these credits may need to be given to the biomass supply company to offset the emissions of the biomass pellet operation (from field to customer). Alternatively, the price of natural gas would go up by about $1.20/Mbtu if CO_2 is taxed at $20 per ton. This would make biomass pellets more attractive to the plant.

Abengoa Ethanol Plant, Hugoton, Kansas. Abengoa is presently moving forward with plans to construct a 100 million gallon per year combination corn/cellulosic ethanol plant in Hugoton, Kansas. As of the writing of this report, Abengoa is in the process of conducting its environmental studies and developing its feedstock supply infrastructure. Abengoa has stated that the plant will require nearly 500,000 "as is" tons of biomass—primarily wheat straw and corn stover—as inputs for the cellulosic ethanol process, as well as to provide thermal energy for the plant. At this time, Abengoa has stated that it plans to collect feedstocks from within 50 miles of Hugoton, which would keep transportation costs as low as possible. At this time, we are unsure if Abengoa will need to go beyond this 50-mile radius and obtain feedstocks from closer to the Greensburg/Pratt areas. However, interested entrepreneurs should contact Abengoa to discuss the potential for supplying the ethanol plant with densified biomass feedstocks.

Summary of Local Market Potential. For any densified biomass product to be commercially viable, it must be at least as cost-competitive and somewhat as convenient as competing fuels. This includes wood pellets as well as fossil fuels. In most cases, pellets are truly a commodity product. A lower cost producer can ship farther and thus compete with smaller, higher production cost pellet mills, even in the smaller mill's own backyard. Agricultural residue pellets are generally lower in grade than wood pellets. If agricultural residue pellets are available in the same market as wood pellets, they would have to sell at a lower price to compete with both wood pellets and natural gas. Biomass pellets are likely to compete very favorably with propane, fuel oil, commercial natural gas rates and electricity, but so will wood pellets. Any entrepreneur who seeks to develop a biomass pelletization facility in the Greensburg/Pratt region should be prepared to spend considerable time and effort on educating potential consumers and developing the market.

Densification Options

We evaluated three potential densified products that could be made from local biomass: pellets, briquettes, and bripells. All three options represent commercial technologies that would create viable market products, and all three can be used in commercial boiler systems to produce heat, power, or combined heat and power. We estimate that a 24,000-ton-per-year plant is the minimum size that should be built to take advantage of economies of scale, labor requirements, and infrastructure. It may be possible, however, to start with a smaller briquette or bripell production level, and scale up as the market develops.

Of the three products, pellets are associated with the most acceptance and consumer awareness, especially in the residential and small commercial sectors. However, the pellet market is still dominated by demand for premium, bagged pellets (less than 1% ash, high Btu) for the residential sector. Most pellet-burning appliances being sold to the residential market today are designed to handle low-ash fuels. Based on the feedstocks available in the Greensburg region, pellets made from a mixture of wood and agricultural residues will be high in alkalis, produce high ash, and contain medium Btu content (see the chemical analysis of the biomass sample pellets located in Appendix A). Without changes to pellet stove technology, there is not likely to be a high demand for this type of pellet from the residential sector. If pellets are the desired product, we suggest they be made either from 100% wood or perhaps a blend of 85%–90% wood with the remainder coming from agricultural residues. The exact blend could be determined through lab tests of various mixture percentages.

For the large commercial or industrial sectors, there are a number of boilers or furnaces on the market that are capable of handling higher ash pellets. Briquettes and bripells are also well-suited for commercial use. Appendix E contains a list of manufacturers of technologies that could burn any of these products in larger applications.

Table ES-7 shows the estimated costs of pellets, briquettes, and bripells. It must be stressed that these numbers are estimates only, and interested entrepreneurs are encouraged to develop their own detailed cost analyses before selecting one technology over another. The numbers below are sensitive to many factors, and changing one assumption can change any value. All of the numbers below were developed assuming a biomass feedstock cost of $65/bdt delivered to the plant.

Table ES-7. Summary of Manufacturing Costs

Product	Plant Capacity (tons/year)	Capital Costs ($)	Employees (FTEs)	Estimated Cost Bagged ($/ton)	Estimated Cost Bulk ($/ton)	Cost for 100% Cedar ($/Mbtu Bulk)	Cost for 50/50 Ag-Cedar Blend ($/Mbtu Bulk)
Pellets	24,000	5,500,000	15	159	135	8.42	8.98
Briquettes	25,000	4,700,000	6	143	123	7.66	8.17
Bripells	24,000	3,000,000	10	154	134	8.36	8.92

Conclusions

There is sufficient biomass located in the region to supply at least one plant creating pellets, briquettes, or bripells. Because cedar represents the highest quality feedstock in the region, the interested entrepreneur may wish to consider sizing a plant based on the quantity of cedar available. Agricultural residues can be added into the product mix at a later date as markets mature. We estimate that 12,500 bdt of cedar can be collected easily, although to get to a minimum sized plant (24,000 tons per year), additional cedar will need to be collected, or ag residues will need to be added. Due to the dry climatic conditions in the region, only agricultural residues from irrigated lands should be considered. Potential target feedstocks include corn stover, corn cobs, sorghum residue. and wheat straw.

There is also sufficient demand for thermal energy in the region. Given the current price of natural gas, it may be more difficult than it was a year ago to convince large commercial or industrial users to switch heating fuels. They could be reminded, however, that fossil fuel prices fluctuate considerably, and it is only a matter of time before prices begin to increase again. But while fossil fuel prices are low, considerable market conditioning and educational efforts will still be needed to persuade current natural gas customers to consider installing a biomass heating system. Biomass fuel will compete better with fuel oil or propane, as these two fuels are more expensive on a $/Mbtu basis.

A pellet, briquette, or bripell plant in the region will create six to 15 jobs, depending upon the technology selected.

Suggestions for Next Steps

This report has confirmed that there is a potential business opportunity in the region to develop some form of densified biomass business, be it pellets, bripells, or briquettes. The following actions are suggested as potential next steps for interested parties:

- Product Development
    - Make sample blends of various feedstock combinations (e.g., cedar/corn stover, cedar/sorghum) in various percentage mixtures
    - Send samples to the lab for chemical analysis, especially to asses ash percentages, Btu content, and alkali content
    - If possible, conduct test burns of products in candidate appliances to assess ash, feed handling, slagging, and odor.

- Feedstock Procurement
  - Identify producers interested in biomass supply options
  - Develop contract mechanisms for biomass supply
  - Assess potential for planting Conservation Reserve Program (CRP) land in switchgrass, mixed grass prairie, or other biomass for specific production of biomass for pellets or bricks. Some sample questions to answer would be:

    What is the best mix of plants for the local region?

    What are the yields and economics versus alternative CRP options?

    What is the best mix of plants in terms of energy content and use?
- Market Development
  - Perform additional market development efforts and educate potential end users about biomass energy
  - Seek state support to organize a local biomass heating workshop in the region
  - Contact large commercial energy users to analyze their actual energy usage and costs. For example, potential regional targets in Kansas could include National Gypsum in Medicine Lodge; the Robert J. Dole VA Medical Center in Wichita; the new Kiowa County Memorial Hospital in Greensburg; Pratt Community College in Pratt; agricultural processing plants in Dodge City; and any federal facilities
  - Continue to identify end use technologies that are commercially available and can be deployed at customer sites.
- Business Analysis
  - Conduct detailed pro forma analyses for bripells, briquettes, and pellets
  - Develop a business plan and conduct a detailed plant design.

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This executive summary provides an overview of a technical report on an assessment NREL conducted in Greensburg, Kansas, to identify potential opportunities to develop a biomass pelletization or briquetting plant in the region.

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D. 12 GREENSBURG, KANSAS, LONG TERM RECOVERY PLAN, LANDFILL GAS POTENTIAL

Philip Shepherd
National Renewable Energy Laboratory

Mr. Doyle Conrad of Greensburg Public Works indicated that they had looked at the potential of recovering landfill gas as an energy resource and concluded that this was impractical.

Greensburg has two landfills. The North Landfill (closed in 1996) covers 40 acres and is classified as a Construction and Demolition Landfill because demolition debris from a recent tornado was placed there even though the landfill had been closed. Construction and Demolition Landfills contain insufficient decomposable material to be considered a source of methane gas.

The South Landfill is an active municipal solid waste facility. However, it is not an acceptable source for landfill gas for several reasons:

- The landfill is much too small. The U.S. EPA recommends a minimum waste content of one million tons if gas recovery is to be considered. The South Landfill was described as a small “seven-acre hole” that will never hold anything close to one million tons.
- It would take more than 1000 years for a community with a population of 1200 to generate the suggested minimum one million tons of household waste needed for a viable landfill gas operation.
- Annual rainfall is very low (ca. 20 inches) and the landfill has no membrane liner to retain the small amount of water it will receive. Therefore, the waste cannot anaerobically decompose to methane in this arid climate.

(November 30, 2007)

D.13 Greensburg, Kansas, Downtown District Heating and Cooling Study

Chris Gaul, PE
National Renewable Energy Laboratory

The town of Greensburg, Kansas, was hit by an EF5 tornado on May 4, 2007, destroying most of the town (EF is the Enhanced Fujita scale for rating the strength of tornadoes in the U.S.). Various government and non-government organizations have undertaken to rebuild Greensburg "green." The Department of Energy (DOE) National Renewable Energy Laboratory (NREL), based in Golden, Colorado, is providing technical assistance to this effort. This paper explores installing a renewable energy district heating and cooling system serving the downtown business district.

Background

District energy systems supply heating and cooling from a central plant to buildings in a concentrated, defined area. Typical heating systems send steam or hot water in buried pipes to buildings and return cooler water to the plant. Air conditioning is provided by circulating cold water to buildings.

District energy systems are typically found in high-density downtown areas of larger cities. They arose in the 19th century as a practical solution to providing heat to dense central business districts (CBD) using coal-fired steam boilers. This eliminated the need for each building to have a coal supply, furnace or boiler, an operator, and ash disposal. As air conditioning came into vogue, it was a natural extension for district steam heat companies to provide cooling as well, through chilled water piped to buildings. CBDs in large cities such as New York and Chicago are served by district energy systems as well as in smaller cities such as Omaha, Nebraska and St. Paul, Minnesota. Beyond CBDs, district energy systems serve college campuses, medical centers, and large installations such as military bases.

District energy systems can use renewable resources or conventional (natural gas or oil for heating, or electricity for air conditioning) resources. For example, Boise, Idaho, has a district energy system that takes advantage of hot water geothermal resources for building heating. Several colleges in the northeast use biomass-based boilers for hot water in district systems.

Geothermal sources have also been used for cooling. The Arts and Sciences Hall at the University of Nebraska was constructed in 1936, it was the first air conditioned college building in America. It was cooled using cold artesian well water. At the time, air conditioning was common only in movie theaters. Free air conditioning in the muggy midwest during the depression was quite an achievement. As the campus grew, a district energy system was built. The artesian water source was inadequate and was replaced with electrically-powered air conditioning. As a modern-day example, Cornell University in Ithaca, New York uses the cold waters of Cayuga Lake to provide 20,000 tons of free cooling for its huge campus. The system reduces cooling energy use by 87%.

Before the tornado, downtown Greensburg consisted of 20 businesses ranging from 1,200 to 15,000 square feet, stretched 1,000 feet along South Main Street. Two buildings remained standing as of October 2007, both damaged. Planners anticipate that the downtown area could reach 300,000 square feet as businesses and dwellings are built over the next 15 years.

The south end of downtown will be anchored by a new city hall. On the north end, one block east of Main Street, is the historic Kiowa County Courthouse, which will be restored. These buildings are not included as part of the 300,000 square foot downtown build-out figure.

District Energy Concepts for Downtown Greensburg

Geothermal Water Cooling

The district energy cooling opportunity for downtown Greensburg is to use a geothermal source. The most intriguing geothermal resource would be to use the town's claim to fame, the Big Well, located at 311 South Sycamore Street, one block west of Main Street. This well is 109 feet deep and 32 feet in diameter. It holds 15 feet of standing water. The water temperature is 55ºF. This cool water was explored as a resource to cool buildings.

The simplest cooling scheme is to draw cold well water and pump it through an insulated supply pipe buried under Main Street. Individual buildings would connect to the system in manhole vaults or buried valves similar to drinking water systems. Air conditioning would be accomplished using conventional chilled water air conditioning coils. Chilled water coils are typically designed for 45ºF water and so they would have to be increased in size for 55ºF water. Warmed water from the building would flow to an underground return pipe. This pipe would not be insulated. At a convenient location at one end of Main Street, a well would be drilled to reinject the water back into the water table, or the Big Well might be used as a return well.

The district cooling system would not consume any water. It would merely borrow it briefly before returning it to the earth. In conversations with the Kansas Department of Health and Environment (KDHE) Bureau of Water in November 2007, KDHE confirmed that this water use is approved. Reinjecting air conditioning water is considered a Class V well. KDHE requires the injection be reported so it can be tracked in their well inventory. KDHE does not require a permit to drill the injection well. A permit is needed for the production well. Since no water would be consumed, KDHE did not foresee any problem issuing the production well permit.

Professional Engineering Consultants of Wichita built a similar system for a school in Garden City, Kansas. The system worked acceptably for a number of years and won energy-efficient design awards. After seven to eight years, the return well started having problems accepting water. Something had changed in the strata around the return well. Perhaps particles from the production well clogged the strata and reduced permeability. The Big Well's 32-foot diameter should be less prone to clogging compared to a small bore well. A dirt separator could also be added to remove fine particles that could clog strata or damage equipment.

In the downtown plan, the production well would be on the north end of Main Street. The return well would preferably be the Big Well. The advantages of using the Big Well include:

- It already exists in the right location, thus saving return well construction costs.
- Greensburg's most famous landmark would be used as part of Greensburg's green initiative.
- It is large in diameter, avoiding clogging problems.

Air conditioning requires not only cooling the air, but adjusting the humidity. The Greensburg climate is at the boundary between the humid midwest and dry high plains. Air conditioning is required to not only cool but dehumidify. Two hundred miles west of Greensburg relative humidity is low enough to use swamp (evaporative) coolers.

Greensburg summer design conditions are 96°F dry-bulb and 72°F wet-bulb. Dew point is 60°F, only five degrees above groundwater water temperature. A cooling system using 55°F groundwater would not effectively dehumidify air using conventional chilled water cooling coils. Additional HVAC equipment would be needed to remove moisture, such as a desiccant system. Desiccant systems are more energy efficient than refrigeration for moisture removal. They are used along the humid Gulf Coast in commercial applications but are not in general use in southwest Kansas. Construction cost estimate for a 1,000-foot cooling water distribution system along Main Street is $368,000 (Appendix A). This does not include connections to individual buildings. Each user would have to pay connection costs to the district cooling system.

The energy cost to pump well water is calculated as 25% of operating a refrigeration-based cooling system (Appendix B). Assuming 60,000 square feet of space in year one and growing to 300,000 square feet in year 15 (Appendix C), the system would generate enough cash flow to cover operating and maintenance expenses, and debt service. The project could pay for itself in a reasonable time frame.

Biobased Heating

Greensburg has 1,600 cooling degree days and 4,800 heating degree days. Heating is the dominant building comfort requirement. For district heating to be economically viable it must have a cost advantage over conventional (individual building) natural gas fueled heating systems.

The new Greensburg downtown will be built to modern codes and its buildings will consume less energy than former structures. Average annual natural gas use for all occupancies is projected at 20,000 BTU/square foot. For the 300,000 square foot assumption for building out downtown, natural gas use would be 60,000 therm/year (1 therm = 100,000 BTU). At $0.80/therm annual natural gas heating costs would be $48,000.

Kiowa County has no known hot geothermal sources. The local renewable fuel resources suitable for district heating include corn grain, corn stover, and corncobs.

Corn prices decreased in inflation-adjusted dollars from 1976 to 2004. Corn burning heating equipment made good sense with cheap corn and expensive fossil fuel. However, in the last two harvest years, corn prices have roughly doubled due to high demand for ethanol production. Corn is not the bargain fuel it was a few years ago; at $3.50/bushel corn costs $0.87/therm and is more expensive than natural gas. Corn grain is better utilized for food or ethanol production instead of solid fuel.

Corn stover is the residue left on fields after grain is harvested. Stover can be gathered in bales typically weighing around 1,500 lb. Stover would have to be processed for use in a heating system. Stover bales cost an estimated $45/ton delivered; fuel cost would be $.38/therm.

Corncobs are superior to corn stover as solid fuel because they can be transported in bulk and handled by conveyors and augers. While no firm data is available, corncob fuel from an established distribution system is estimated to cost $35/ton delivered. Fuel cost would be $0.32/therm.

Corn crop residue in the form of stover or cobs could be burned in a special boiler to produce hot water that would be piped to buildings. The boilers burn clean with no smoke or odor once they are up to operating temperature.

The energy cost for corncob residue heat is 40% of gas-fired heating equipment ($0.32/therm compared to $0.80/therm). The maximum cash flow switching from natural gas to the lowest cost renewable fuel is: ($.80 natural gas therm - $0.32 corncob therm) X 60,000 therms/year = $28,800/year. Corncob fuel would have operating and maintenance costs not associated with natural gas estimated at $15,000/year. Assuming 60,000 square feet of space in year one and growing to 300,000 square feet in year 15 (Appendix D), the system would not generate enough cash flow to cover operating, and maintenance expense, even without debt service.

Geothermal Heat Pumps Heating and Cooling
Another way to use 55°F groundwater is to supply water-source geothermal heat pumps for heating and cooling. This arrangement would eliminate the need for individual building owners to drill wells in the constricted downtown area. If Greensburg's electric power was derived from wind or another renewable resource, the downtown could be entirely heated and cooled with renewable energy.

Piping
The key element of a district energy system is the buried pipes. These pipes have to be sized to handle the maximum predicted load. Wells can be added as needed but undersized piping is difficult to replace. They are installed similar to water mains, which are sized based on rough guesses of future requirements. But unlike water mains, district energy systems need to be competitive with stand-alone energy systems. Because stand-alone energy systems are available, the high uncertainty of rate of growth in a situation like the Greensburg downtown area make it difficult to justify investing in buried piping for district heating and cooling. If growth is slow, and system subscribers come on slowly, the cash flow will not support the repayment of financing for the piping.

A good time to install the underground pipes would be when the landscaped strip is being built along Main Street. When the sidewalks are torn up, piping can be installed on the business side of the landscaping. Taps could be installed to serve known buildings.

Conclusions

District heating using corncob residue is not recommended for Greensburg because operating costs offset energy savings. Even if lower operating costs were possible, the price difference between corn residue and natural gas is not sufficient to finance a biofueled boiler plant and district heating system. There is not enough cash flow to support a district heating plant built with borrowed money.

The greater cost differential between traditional cooling and groundwater-based cooling made district cooling initially attractive; however, the cost of piping drives the economics negative.

The conclusion is: district heating and cooling is not recommended for Greensburg. The costs for such systems would be better applied to individual buildings using quality low-energy building construction, high efficiency natural gas heating equipment, and SEER 14+ air conditioners. There would then be no risk of the city being saddled with underutilized infrastructure.

If piping and wells could be donated or helped financially, a district energy system based on 55°F water for direct cooling and heat pumps would definitely add to Greenburg's green town image.

(January 2008)

Attachment A

Cost Estimate

Project: Greensburg District Cooling System

Mechanical

Page : 1 of 1

Date: 12/15/2007
By: Chris Gaul

ITEM	QUANTITY		MATERIAL		LABOR						TOTAL
	No.	Unit	Per unit	Total	Unit Hrs	Rate	Ext Hrs	Total	Equipment	Total	
Engineering`											$50,000
Irrigation well	1	LS	$27,700.00	$27,700.00	0.00	$60	0	$0.00			$27,700
Pump and gearhead	1	LS	$22,000.00	$22,000.00	0.00	$60	0	$0.00			$22,000
Power unit	1	LS	$10,000.00	$10,000.00	0.00	$60	0	$0.00			$10,000
Pipe - 8" PVC insulated	1500	LF	$32.00	$48,000.00	0.67	$60	1000.5	$60,030.00			$108,030
Pipe - 8" PVC	1500	LF	$14.80	$22,200.00	0.09	$60	138	$8,280.00			$30,480
Misc. Piping	1	LS	$10,000.00	$10,000.00				$10,000.00			$20,000
Trenching	1800	CY	$2.50	$4,500.00	0.08	$60	144	$8,640.00	$1.43	2,574	$15,714
Pipe Bedding	1500	LF	$3.83	$5,745.00							$5,745
Controls	1	LS									$30,000
Estimating Contigency											$64,000
Subcontractor Overhead & Profit - 20%	1	LS		$30,029.00				$17,390.00			$47,419
								Sheet Total=			$431,088

Attachment B

Greensburg District Cooling System

Energy Cost to Pump Well Water (assumed 25% of operating a refrigeration-based cooling system)

Downtown buildout 300,000 Blended Power Cost / kWH: $0.11

Occupancy	Area-%	Area-Ft.2	Ft.2/ton	Tons	GPM	Annual DX cooling kWH/Ft.2	Annual kWH DX cooling	Annual Ton-Hours (1 kWH/T-H)	Annual DX Cooling cost	Annual Well Water Cooling kWH (0.25 kWH/T-H)	Annual Water Well Cooling Cost
Restaurant	15%	45,000	250	180	540	6.0	270,000	270,000	$ 29,700	67,500	$ 7,425
Office	30%	90,000	350	257	771	4.3	387,000	387,000	$ 42,570	96,750	$ 10,643
Retail	35%	105,000	350	300	900	4.3	451,500	451,500	$ 49,665	112,875	$ 12,416
Apartment	20%	60,000	500	120	360	3.0	180,000	180,000	$ 19,800	45,000	$ 4,950
Totals	100%	300,000		857	2,571		1,288,500	1,288,500	$ 141,735	322,125	$ 35,434
								Avg$/Ft.2	$ 0.47		$ 0.12

Attachment C

Cashflow Analysis for District Cooling

Downtown build out cashflow analysis 2007 dollars

Year	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013
Restaurant sq. ft.	45,000	42,750	40,500	38,250	36,000	33,750	31,500	29,250	27,000	24,750	22,500
Office sq. ft.	90,000	85,500	81,000	76,500	72,000	67,500	63,000	58,500	54,000	49,500	45,000
Retail sq. ft.	105,000	99,750	94,500	89,250	84,000	78,750	73,500	68,250	63,000	57,750	52,500
Apartment sq. ft.	60,000	57,000	54,000	51,000	48,000	45,000	42,000	39,000	36,000	33,000	30,000
	300,000	285,000	270,000	255,000	240,000	225,000	210,000	195,000	180,000	165,000	150,000
Conventional Air-conditioning Energy Cost @ $0.47/Ft.2	$ 141,000	$ 133,950	$ 126,900	$ 119,850	$ 112,800	$ 105,750	$ 98,700	$ 91,650	$ 84,600	$ 77,550	$ 70,500
Well Cooling Energy Cost @ $0.12/Ft.2	$ 36,000	$ 34,200	$ 32,400	$ 30,600	$ 28,800	$ 27,000	$ 25,200	$ 23,400	$ 21,600	$ 19,800	$ 18,000
Annual Energy Savings Well vs. Conventional	$ 105,000	$ 99,750	$ 94,500	$ 89,250	$ 84,000	$ 78,750	$ 73,500	$ 68,250	$ 63,000	$ 57,750	$ 52,500
Well Debt Service @ 6% Interest	(44,376)	(44,376)	(44,376)	(44,376)	(44,376)	(44,376)	(44,376)	(44,376)	(44,376)	(44,376)	(44,376)
Well O&M costs	(12,000)	(12,000)	(12,000)	(12,000)	(12,000)	(12,000)	(12,000)	(12,000)	(12,000)	(12,000)	(12,000)
Annual Well Cashflow	48,624	43,374	38,124	32,874	27,624	22,374	17,124	11,874	6,624	1,374	(3,876)
Cumulative Cost Savings	$ 142,738	$ 94,114	$ 50,739	$ 12,615	$ (20,259)	$ (47,883)	$ (70,258)	$ (87,382)	$ (99,256)	$ (105,880)	$ (107,255)

Attachment D

Cashflow for Biobased (corncob) District Heating System

Year	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Restaurant sq. ft.	45,000	42,750	40,500	38,250	36,000	33,750	31,500	29,250	27,000	24,750	22,500	20,250	18,000	15,750
Office sq. ft.	90,000	85,500	81,000	76,500	72,000	67,500	63,000	58,500	54,000	49,500	45,000	40,500	36,000	31,500
Retail sq. ft.	105,000	99,750	94,500	89,250	84,000	78,750	73,500	68,250	63,000	57,750	52,500	47,250	42,000	36,750
Apartment sq. ft.	60,000	57,000	54,000	51,000	48,000	45,000	42,000	39,000	36,000	33,000	30,000	27,000	24,000	21,000
	300,000	285,000	270,000	255,000	240,000	225,000	210,000	195,000	180,000	165,000	150,000	135,000	120,000	105,000
Gas Heating Cost @ $0.80/therm	$ 48,000	$ 45,600	$ 43,200	$ 40,800	$ 38,400	$ 36,000	$ 33,600	$ 31,200	$ 28,800	$ 26,400	$ 24,000	$ 21,600	$ 19,200	$ 16,800
Biofuel Heating Cost @ $0.32/therm	$ 19,200	$ 18,240	$ 17,280	$ 16,320	$ 15,360	$ 14,400	$ 13,440	$ 12,480	$ 11,520	$ 10,560	$ 9,600	$ 8,640	$ 7,680	$ 6,720
Biofuel O&M cost	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Annual Savings	$ 13,800	$ 12,360	$ 10,920	$ 9,480	$ 8,040	$ 6,600	$ 5,160	$ 3,720	$ 2,280	$ 840	$ (600)	$ (2,040)	$ (3,480)	$ (4,920)
Total Savings	$ 46,560	$ 32,760	$ 20,400	$ 9,480	$ -	$ (8,040)	$ (14,640)	$ (19,800)	$ (23,520)	$ (25,800)	$ (26,640)	$ (26,040)	$ (24,000)	$ (20,520)

D.14 Greensburg Recovery Program – The Feasibility and Benefits of Fuel Cell Cogeneration

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National Renewable Energy Laboratory

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Wind Utility Consulting

Greensburg Recovery Program

THE FEASIBILITY AND BENEFITS OF FUEL CELL COGENERATION

UTC Power
A United Technologies Company

WP0001
17 March 2008

GREENSBURG RECOVERY PROGRAM

THE FEASIBILITY AND BENEFITS OF FUEL CELL COGENERATION

WHITE PAPER

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UTC Power
A United Technologies Company

1. PURPOSE

UTC Power is pleased to submit this white paper to the National Renewable Energy Laboratory (NREL), the City of Greensburg, and various other Greensburg Recovery Program stakeholders so that fuel cells may be considered for the rebuilding effort in concert with other energy technologies. We hope that this paper will provide useful information about the cogeneration capabilities of fuel cells and, specifically, the applicability, benefits, economics and environmental considerations of integrating this technology into the rebuilding and recovery of this community.

2. THE PURECELL® MODEL 400 FUEL CELL SYSTEM

The PureCell® Model 400 energy solution is a 400 kW phosphoric acid fuel cell (PAFC) slated for market introduction in the first half of 2009. This product is a next generation technology, drawing on the experience and success of the world's most versatile and proven fuel cell system, the PureCell® Model 200 solution. The PureCell® Model 200 fuel cell system has accrued over 8.5 million fleet hours on approximately 300 installed systems since 1992. The PureCell® Model 400 fuel cell system distinguishes itself from all other fuel cell products in the marketplace with its very high cogeneration system efficiency (about 85 percent), and its 10 year cell stack life (more than double the life of competing fuel cell technologies). It can be fueled by pipeline natural gas (2009) or anaerobic digester gas (ADG; available 2010). The electric-only system efficiency is 42 percent (LHV) at startup, with an average lifetime electrical efficiency of 40 percent (LHV).

The PureCell® Model 400 system product datasheet, provided as Attachment A, describes the performance and physical characteristics of this product in detail.

3. POTENTIAL APPLICATIONS

Fuel cell application economics are driven by the following considerations:

- *Favorable spark spread* – Spark spread is the price difference between the fuel cost (*e.g.*, natural gas) and electricity being displaced. The higher the electricity costs are relative to the cost of gas, the better the value proposition is for any type of cogeneration system.

- *Available federal or state incentives* – As of right now, the federal investment tax credit of $1,000/kW is set to expire on 31 December 2008. The fuel cell industry is working to have the deadline extended beyond this date. There are currently no state fuel cell incentives in Kansas.

- *Ability to baseload the power and thermal output of the fuel cell* – Usually, it is easier to baseload power and more difficult to baseload heat use at many types of buildings. The PureCell® system offers up to 1.7 MMBtu/hr of useful heat to customers for space heating, industrial processes or domestic hot water. If natural gas costs about $8/MMBtu and converts to heat at 80 percent, then this fuel cell heat is worth about $20/hr or about $140,000/year if fully utilized.

- *Value of energy reliability* – If the grid fails, then having on-site fuel cell power handling mission critical or life safety related electrical loads has financial value, though it is sometimes difficult for a specific dollar value to be assigned to this. The PureCell® system has delivered this type of assured power for many customers since 1992.

The optimal application of fuel cells in Greensburg involves two possible installation configurations:

a. Central plant

b. Dispersed concept.

3.1 CENTRAL PLANT

Recent NREL commissioned reports estimate a ~1.5 MW base electric load for the entire Greensburg community. The peak load is projected to be about 4.5 MW (summer months). Four 400-kW PureCell® systems would deliver 1.6 MW of power and could produce 6.8 MMBtu/hr of hot water. Since the current projections for thermal demand in residential Greensburg do not appear to call for sizable heat distribution, a large commercial or industrial entity with a requirement for large amounts of thermal energy might be attracted to the area by the promise of useable heat at a reasonable discount. The total economic value of the PureCell® central plant would be about $560,000 per year (assuming gas costs of $8/MMBtu, and an 80 percent conversion efficiency). At a plant life of 20 years, this projects to about $11.2 million (assuming no gas price escalation). Additionally, the central plant concept offers the possibility of supporting up to 1.6 MW of Greensburg town power loads if the grid fails. Such power security would offer great peace of mind to the town and its residents.

A PureCell® central plant is envisioned to employ at least one or two Greensburg citizens as UTC Power contractors. In this role, these contractors would be trained to operate and maintain the central plant.

3.2 DISPERSED CONCEPT

One or more fuel cells could be located at various sites that require power, heating, cooling and/or backup power. Each PureCell® system can make about 50 tons of chilled water for space cooling (air conditioning) through the use of absorption chiller technology. Recent data suggests the new high school (125,000 sq ft) and hospital (38,000 sq ft) electrical loads together could be supported by a single 400 kW fuel cell. As other large facilities emerge in the recovery buildout, they could be assessed for need and equipped with fuel cell cogeneration and backup power as well.

A typical system integration concept is shown in ***Figure 1***.

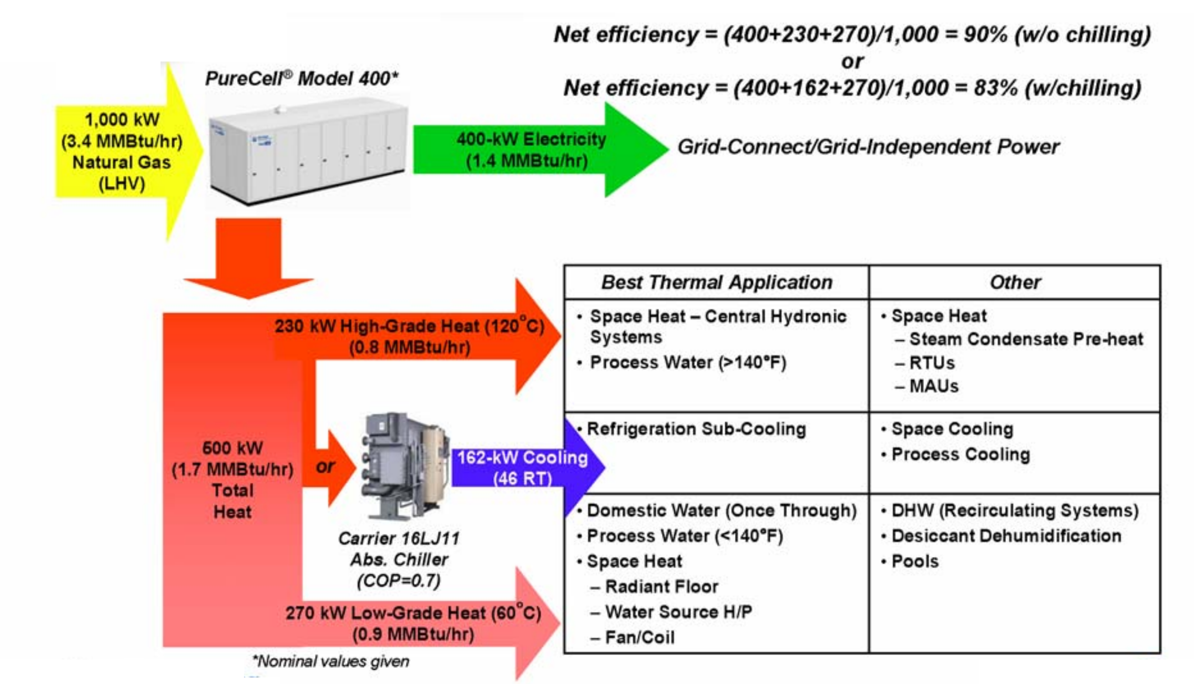


Figure 1. *Typical PureCell® Model 400 CHP System Installation*

4. FUEL CELL ECONOMICS IN GREENSBURG

The following assumptions were used to assess fuel cell economics in Greensburg.

- Input assumptions:
  - Each fuel cell installed cost = \$3,000/kW or \$1.2 million each
  - Annual service cost = \$68,000 per fuel cell or about 2.0¢/kWh
  - Fuel cell uptime = 95 percent
  - Rated power output = 400 kW
  - Electric energy produced per year, per fuel cell = 3.33 million kWh/yr
  - Natural gas price = \$8/MMBtu.
- Output:
  - Cost of power generation = 12.5¢/kWh (if 0 percent fuel cell waste heat is used)[1]
  - Cost of power generation = 7.5¢/kWh (if 100 percent fuel cell waste heat is used)[1]
  - Value of 100 percent waste heat use = \$140,000/yr (about 4.0¢/kWh).

Fuel cell economics are compared to pre-tornado electricity costs in ***Figure 2***. The pre-tornado data was provided by Greensburg's Steve Hewitt via NREL.

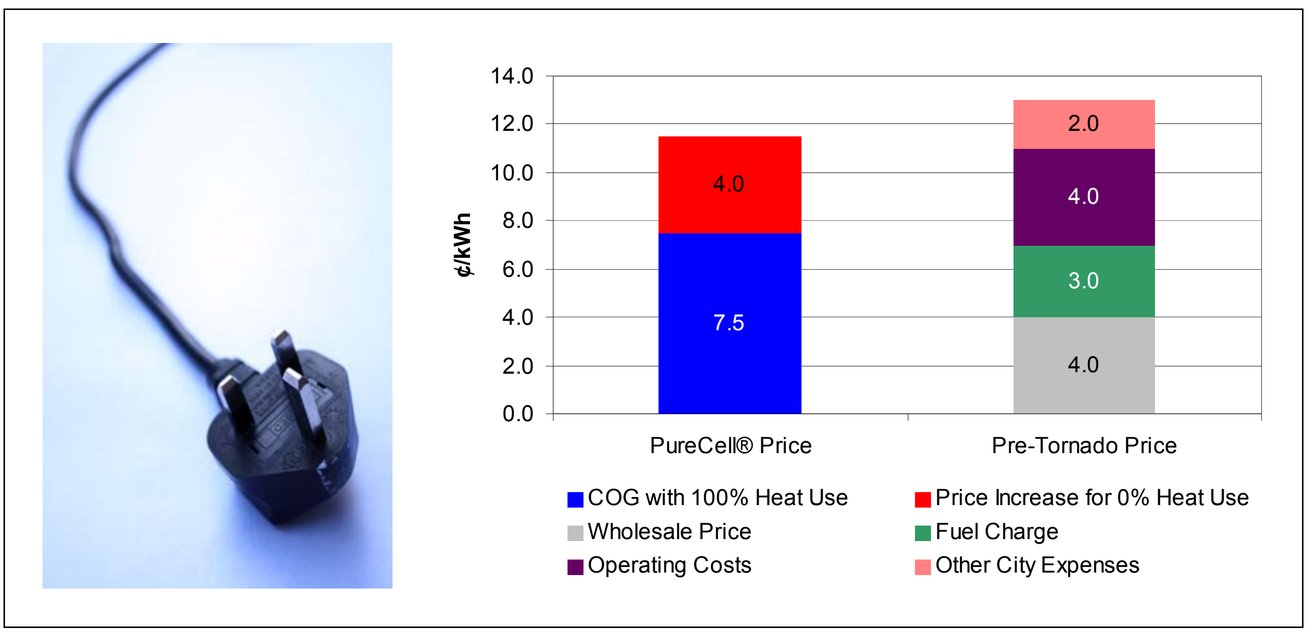


Figure 2. *Fuel Cell Economics Versus Pre-Tornado Electricity Costs*

[1] If Greensburg uses the dual electric mode capability of the PureCell® system and its ability to operate both grid connected or grid independent, then the cost of diesel generators will be avoided. UTC Power approximates this avoided cost as about 1¢/kWh (capital plus operating/service) and these values would be about 11.5¢/kWh and 6.5¢/kWh, respectively.

5. ENVIRONMENTAL CONSIDERATIONS

5.1 AIR EMISSIONS

The carbon dioxide generation potential of a 1.5-MW PureCell® system is compared to the Kansas grid, as well as solar and wind energy production, in ***Figure 3***. The chart shows that the carbon dioxide generation potential of a fuel cell project with 0 percent heat use is roughly equal to a wind project with a 41-percent capacity factor. However, if 100 percent of the fuel cell heat is used, then carbon dioxide generation is reduced significantly by about 62 percent.

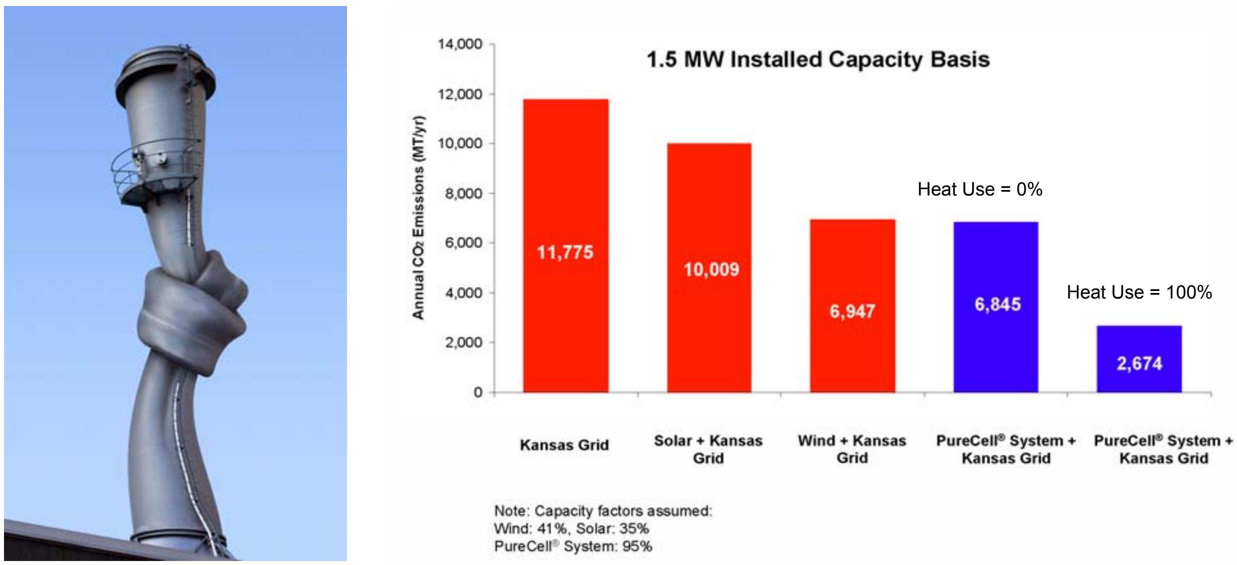


Figure 3. *Comparison of Carbon Dioxide Generation By Source*

Additionally, the PureCell® fuel cell solution avoids other conventional pollutants that cause health and environmental issues. The emissions advantages of the PureCell® system are illustrated in ***Figure 4***.

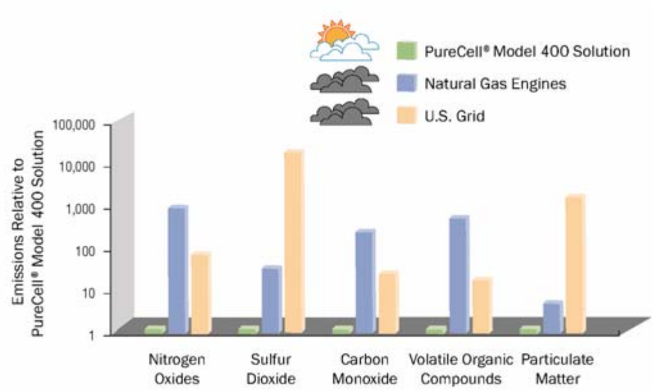


Figure 4. *Emissions Advantages of the PureCell® System*

5.2 WATER CONSERVATION

Utility scale power generation consumes large quantities of water. According to the U.S. Geological Survey (1995 data), the Kansas grid uses 556 gal/MWh of water. The PureCell® system uses very little water by comparison. If PureCell® systems are used to displace 1.5 MW of grid power, about 7 million gallons of water per year (relative to the Kansas grid) would be conserved. This comparison is depicted in ***Figure 5***.

A 1.5-MW PureCell® System Could Save Greensburg Roughly 7 Million Gallons of Water Annually

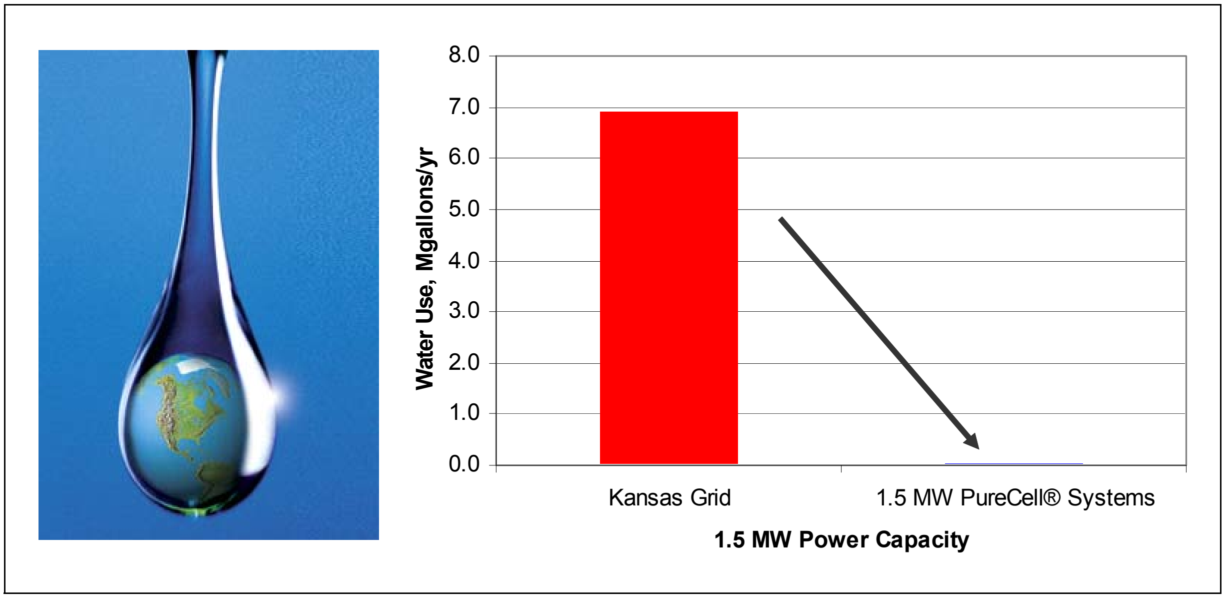


Figure 5. *Comparison of Water Use*

6. OTHER FUEL CONSIDERATIONS

The PureCell® system can operate on ADG fuel as stated previously. However, there is currently no source of ADG in Greensburg. If it looks like a source will emerge in the buildout of the community, then this fuel could be considered as a fuel source for an installed PureCell® system. The ADG source could be blended with pipeline natural gas to produce power while reducing fuel costs.

UTC Power has also delivered and operated a PureCell® Model 200 system fueled by hydrogen. If NREL is considering converting wind energy to hydrogen, then UTC Power would be pleased to discuss this fuel option in greater detail.

APPENDIX A — PURECELL® MODEL 400 SOLUTION DATASHEET

The technical datasheet for the PureCell® Model 400 is replicated on the following pages.

Model 400

MODEL 400 PureCell® System

Introducing a new generation of fuel cell technology: The PureCell® Model 400 Energy Solution.

UTC Power is a world leader in developing and producing fuel cells for on-site power, transportation, space and defense applications. We are committed to providing high quality solutions for the distributed energy market that increase energy productivity, energy reliability and operational savings for our customers. Building on our unmatched operational experience and a technology platform proven at more than 260 sites worldwide, UTC Power is pleased to offer an advanced fuel cell energy solution for the commercial marketplace.

The ultra clean and quiet PureCell® Model 400 fuel cell can provide up to 400 kW of assured electrical power, plus up to 1.7 million Btu/hour of heat, for combined heat and power applications. And with energy efficiencies more than double those of traditional power sources, the PureCell® Model 400 system is an energy solution that will not only help you conserve precious resources, it will save you money, shield you from operational interruption, and secure your place at the forefront of environmentally sustainable business practices.

Performance Characteristics

Power

Electric power	400 kW/471 kVA initial 400 kW lifetime average (10 yr) 360 kW initial (ADG)
Voltage/frequency	480VAC/60 Hz/3 phase§ 400VAC/50 or 60 Hz/3 phase

Efficiency

Electrical (LHV)	42% initial/40% nominal (5 yr)
Overall (LHV)	90%‡

Fuel

Supply	Natural gas or ADG*
Consumption (HHV)	1,054 kW (3.60 MMBtu/hr) initial 1,110 kW (3.79 MMBtu/hr) average
Pressure	1.0 to 3.5 kPA (4 to 14 in. water)**

Heat Recovery

Low grade (60°C/140°F supply)†	450 kW (1.537 MMBtu/hr) initial 500 kW (1.708 MMBtu/hr) nominal
High grade (121°C/250°F supply)†	200 kW (0.683 MMBtu/hr) initial 230 kW (0.785 MMBtu/hr) nominal

Other

Noise	<65 dBA at 10m (33 ft) with no heat recovery <60 dBA at 10m (33 ft) with full heat recovery
Overhaul interval	10 yr (major)

Emissions

NO_x	0.016 kg/MWh (0.035 lb/MWh)
CO	0.004 kg/MWh (0.008 lb/MWh)
CO_2	508 kg/MWh (1120 lb/MWh) average
SO_x	Negligible
Particulate matter/VOCs	Negligible

Water

Consumption	None (up to 30°C/86°F ambient)
Discharge	None (normal operating conditions)

energy
Reinvented

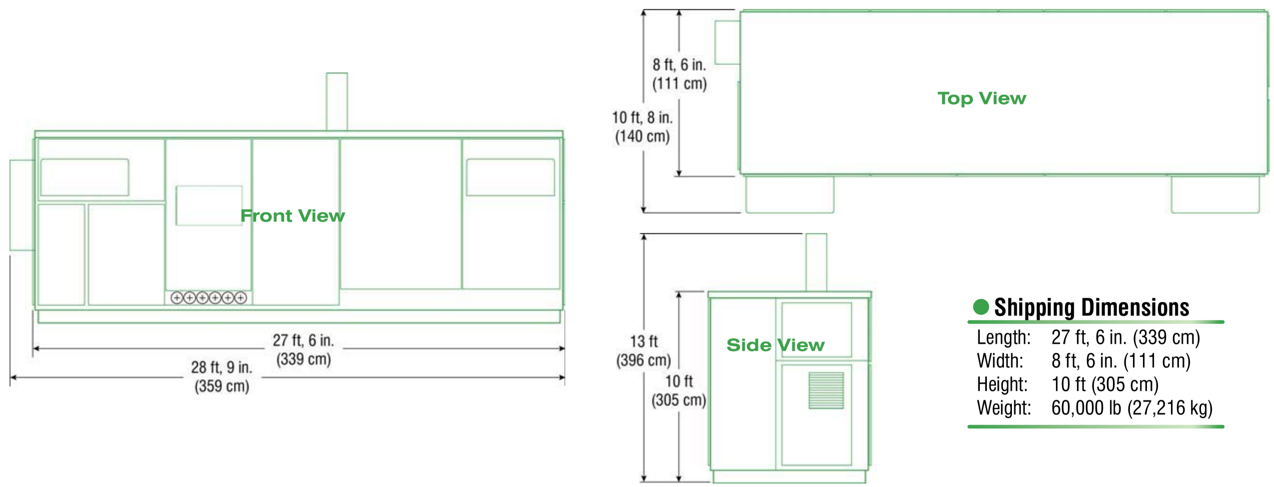
* All given characteristics are for a natural gas application, unless otherwise noted. Maximum allowable levels for natural gas components are documented separately in the PureCell® Model 400 System Installation Design Guide. ADG applications require an additional gas processing unit. ** Gauge pressure. † Available heat at rated power. Low-grade heat assumes a return temperature of 27°C (80°F); high-grade heat assumes a return temperature of 90°C (194°F). If high-grade heat is utilized, the remaining value will be available as low-grade heat. ‡ Overall efficiency as given assumes full thermal utilization. § Operating range from -29° to 45°C (-20° to 113°F) at up to 150m (429 ft).

Model 400

MODEL 400
PureCell® System

Physical Characteristics

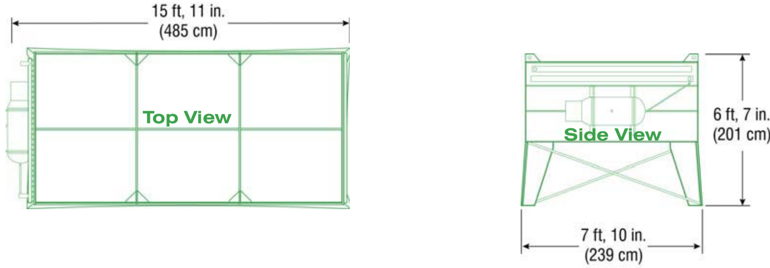
Power Module



Shipping Dimensions

Length: 27 ft, 6 in. (339 cm)
Width: 8 ft, 6 in. (111 cm)
Height: 10 ft (305 cm)
Weight: 60,000 lb (27,216 kg)

Cooling Module



Shipping Dimensions

Length: 15 ft, 11 in. (485 cm)
Width: 7 ft, 10 in. (239 cm)
Height: 6 ft, 7 in. (201 cm)
Weight: 3,190 lb (1,447 kg)

The manufacturer reserves the right to change or modify, without notice, the design or equipment specifications without incurring any obligation either with respect to equipment previously sold or in the process of construction. The manufacturer does not warrant the data on this document. Warranted specifications are documented separately.

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