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A statistical regression model to determine financial cash flow for wind energy based on tax structure

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ABSTRACT

A financial cash flow for wind turbines based on a energy entity's tax structure. Using statistical regression of various wind turbines and wind maps, a theoretical model for energy output was calculated. The turbines were separated by the rated size of the turbine. With the theoretical model, financial output was generated for four different types of tax structures. A total of eight test cases were simulated. Special consideration was given to the impact of Production Tax Credits (PTC) and Renewable Energy Production Incentives (REPI). The object is to determine what type of business and tax structure would have the greatest potential impact on a local or rural community.

CHAPTER 1. INTRODUCTION

Since the 1990's, wind energy and wind turbines have been increasing. Due to this development, several policy questions have arisen. The first question is whether wind energy is feasible to develop. If wind development is unfeasible, relative to other alternatives for electricity generation, should tax credits/incentives or government subsidies be used to encourage the development? In addition, should wind development be open to all or should certain business structures be given preferential incentives? Policymakers, government officials, and leaders are searching and examining viable solutions to these questions.

Increase in Future Energy Consumption

By the year 2020, 363 gigawatts of new generating capacity will be needed in the United States to meet current and increased consumption and to replace retired electricity generators (NREL 2001). Since 1987, total consumption of energy in the state of Iowa has increased an average of 2.1 percent (Iowa DNR 2004). Since 1979, the consumption of coal has increased by 89.6 percent and an average of 4.5 percent (Iowa DNR 2004).

Table 1. Expected annual percent increase of electricity usage in the United States

Sector	Percent increase per year from 1997 - 2020
Residential	1.6 Percent
Commercial	1.4 Percent
Industrial	1.1 Percent

(NREL 2001)

US Insecurities and Dependency on Imported Oil

With the war on terrorism, especially in the Middle East, government officials are concerned about U.S. energy prices and security. The Department of Homeland Security has cited concerns over the security of oil reserves, nuclear power plants, and the disposal of nuclear waste (NNSA 2004). One consideration is the United State's dependency on imported oil, and the vulnerability to decisions made by OPEC.

In 1976, the United States imported 36 percent of the domestic oil used in the United States, while in 2000 it increased to 55 percent (energy.gov 2001). The Department of Energy (DOE) predicts by 2020, the United States will be 65 percent dependant on imported oil. This increase is the result of decreased domestic production and increased imports. For example, since 1992, the production of domestic oil has fallen 17 percent, while consumption has increased 14 percent. Since 1990, the consumption of natural gas in Iowa has increased by an average of 2.2 percent (Iowa DNR 2004).

Fluctuation of Energy Prices

The demand for electricity, gasoline, and power has been steadily increasing over the last decade in the United States. In one eastern state, the price of heating oil went from $0.98 per gallon in October 1999, to $2.03 by February 2000 – a 107 percent increase (Energy Supply and Demand 2000). From 1977 to 1987, energy prices in Iowa have doubled (Iowa DNR 2004). The price of natural gas increased an average of 4.7 percent for the residential sector. An average of 9.1 percent for industrial sector, and an average of 4.9 percent for the commercial sector (Iowa DNR 2004). Partly due to the United State's economic growth during the 1990's, there has been an increased demand for electrical products, air travel, and the less fuel-efficient sport utility vehicles (Energy Supply and Demand 2000). The increased price of natural gas has led to increased production costs for farmers, since natural gas is the primary ingredient for the fertilizer anhydrous ammonia. As the price of natural gas increases, the price of production increases for farmers and households.

Power Outages and Shortages

Much of Southeast Canada and the Northeast U.S. from New York to Ohio experienced a black out in August 2003. The blackout was caused by inadequate transmission grid capacity and management issues (GAO 2003). Similarly, some geographical parts of the United States, such as California, experienced rolling blackouts during the summer of 2001. At that time, 63 percent of all energy was supplied by hydropower for the states of Washington, Oregon, Idaho, and Montana (Mapes 12 June). According to the National Weather Service, during the summer of 2001, the Cascade Mountain Range snow pack was 55 to 65 percent below normal, creating a drought in Washington and a shortage of hydroelectricity in the Pacific Northwest (Mapes 12 June).

Demand for Environmentally Friendly Energy Sources

Consumers are requesting clean and green energy alternatives and programs from their electric utilities. Public utility commissions and state policy makers are increasingly requiring certain electric utilities to offer such programs. States such as Iowa, Minnesota, Montana, and Washington all require certain utilities to allow utility customers to buy power generated from renewable energy sources often referred to as "green power" (DSIRE 2003). Also, most states require utility green pricing programs (DSIRE 2003). In addition, 18 states require that a certain percentage of overall energy from a utility be generated from renewable energy sources (DSIRE 2003). Over the past few years, the technology has been developed, researched, and tested in order to have the cost of wind energy able to compete with other more conventional forms of energy, such as, coal, natural gas, nuclear power, and hydroelectricity.

Wind Powering America

The United States Department of Energy has developed a national plan with specific goals for increasing wind energy production.

- Provide 5% of the nation's electricity from wind by 2020
- Provide 500 megawatts (MW) of the nation's electricity from wind by 2005
- Provide 10,000 MW of the nation's electricity from wind by 2010
- Increase the number of the states with at least 20 MW of wind generation to 16 states by 2005 and at least 24 states by 2010
- Increase the consumption of wind power by the federal government to 5% by 2010

Rural America Vitality

In addition, policymakers and rural interest groups are searching for ways to increase the economic viability of rural areas, especially for communities with a high potential for wind energy and heavy dependence on agriculture. As the number of wind farms increase, community leaders are interested in the economic benefits retained in the local economy. The construction of wind farms increase temporary and permanent jobs, generate property taxes, increased revenues for landowners, and generate operating margins for owners or investors. Wind energy has the potential to replace external purchases of coal with local area purchases of renewable resources, which can be a significant economic boost for some rural communities in the United States.

Problem Statement

The objective of this thesis is to analyze alternative business structures in the context of current policy incentives in order to determine the approaches to wind energy development that would generate the greatest level of positive financial returns and rural community fiscal impacts. As a result due to the expected increase in energy consumption, United State's security and dependency on imported oil, fluctuation of energy prices, power outages and shortages, demand for environmentally friendly energy sources, Department of Energy's Wind Powering America initiative, and sustaining rural America vitality, a study on the financial cash flow from wind energy given different tax and business structures will be conducted based on:

1. A review of existing fiscal models and assess for limitations
2. Collecting data relevant for conducting a financial analysis of wind energy
3. Developing an internet based financial model
4. Using a financial model to analyze alternative combinations of business structures and policy incentives.

CHAPTER 2. REVIEW OF LITERATURE

A search of academic literature, government web sites, private web sites, and other printed material revealed the inadequacy of material related to a general wind energy financial model. Three main components were searched within the literature: discussions of turbine data, energy generation calculations, and financial information for different industry sectors. There was an attempt to find studies that encompass all three concepts.

Current Models

As the desire and need for wind energy increases, units of government, private entrepreneurs, and utilities are looking for simple and inexpensive models to analyze economic consequences. The Danish Wind Turbine Industry Association provides a wind energy economics internet-based calculator. The National Renewable Energy Laboratory (NREL), a DOE government research laboratory based in Colorado, has developed a wind energy financial model, the RET Finance Model. The efforts of NREL are partially due to the DOE's Wind Powering America (WPA) initiative.

The Iowa Energy Center, through its web site, provides wind speed data for communities in the state of Iowa. The web site, allows the user to specify the wind turbine from a list of turbines and receive exact wind speeds for a given altitude. By allowing the user to specify the exact turbine, the energy output is more accurate. The American Wind Energy Association (AWEA) and the Danish Wind Turbine Industry Association (Wind Energy 2004) web sites also provide useful information about wind turbines and wind energy. These two sites provide most of the necessary information regarding wind turbines, their components, Betz' Law, engineering aspects, and different wind speed probability distributions (AWEA 2004 and Wind Energy 2004).

Wind turbine manufacturer web sites provide free wind turbine specifications. This allows analysts to obtain information on possible turbines for wind energy sites. However, the web sites usually do not provide cost information. Despite this absence, these web sites provide technical engineering data that is often beyond the scope of the user such as detailed electrical, mechanical, and engineering information.

Turbine Data

Turbine data such as rotor diameter, turbine height, and the maximum generation rating of the turbine is necessary to calculate energy production. Ideally, knowing the exact turbine data would allow for the most accurate financial output calculations.

The rotor diameter is important because it generates the wind energy production per square meter or foot. The rotor diameter is also directly proportional to the height of the turbine. Most land-based or utility sized turbines have rotor diameters that exceed 40 meters, and can reach 90 meters, such as the Nordex N90-2300, which has a rotor diameter of 90 meters. (Nordex 2003).

The rating of the turbine gives the user the maximum potential energy that can be produced in one hour. The rated speed is the point when the wind speed allows for maximum energy production. If a wind turbine is rated at 750 kW, to achieve 750 kWh, the speed of the wind must be equal or greater than the rated speed.

The final turbine variable of importance is the height of the turbine, which is needed to provide the best wind speed estimates. The variation in turbine height can greatly affect the wind speed, thus affecting the energy production, which in turn would affect overall revenues and the profitability of the turbine. In addition, increased height increases the overall turbine cost. In most cases, the turbine height begins at 50 meters, and may go up to 100 meters (GE Power and Nordex 2004).

Wind Speed

The more specific the geographic and spatial information obtained, the higher degree of accuracy will be reflected in the financial output, since the financial output is dependant on taxes, financial incentives, and economic viability. Spatial characteristics include environmental and ecological information, with the distance from distribution and transmission lines, and the distance from energy consumption regions.

Within certain geographical conditions, energy production can be optimized. Several areas in Iowa meet the necessary conditions for optimal wind energy production. Wind speeds are classified into seven different classes by meters per second (m/s) (Wind Energy 2004).

Table 2. Wind class

Class at 50 meters	Beginning speed	Ending Speed
1	0 m/s	<5.6 m/s
2	5.6 m/s	6.4 m/s
3	6.4 m/s	7.0 m/s
4	7.0 m/s	7.5 m/s
5	7.5 m/s	8.0 m/s
6	8.0 m/s	8.8 m/s
7	>8.8 m/s	

(NWTC 1993) meters per second (m/s)

Obstacles, such as trees, buildings, natural earth formations, silos, or other objects that impede the flow of the air, should be avoided in site selection. States in the Midwest, such as Iowa, are ideal because many locations have few or no wind obstacles.

Another way to optimize the location of a wind farm is to take advantage of natural ways in which the air speed is increased. One option is to place wind turbines in a natural tunnel. The wind turbine is placed between two tall objects, forcing the air to compress, and increasing the speed as it passes through the tunnel. Some care should be taken in locating the turbine in a tunnel, placing it where there is turbulence may outweigh the effects of the tunnel (Wind Energy 2004).

Another method of increasing wind speed is to place the turbine on a gently sloped hill. As the air reaches the hill, the air is compressed and the speed increases at higher elevations as the air expands on the hill. If the hill is too steep, however, there will be instances of turbulence in the airflow, which may negate the positive effects of the hill on increasing wind speeds. Given the current technology of wind turbines, it is suggested that the average wind speed should exceed 7 meters per second (m/s) or 15.7 mph at 50 meters.

Energy production will remain constant when the wind speeds are equal to or exceed the rated speed. Energy production stops when wind speeds reach the cut out speed. Typically, a wind turbine with a cut in speed of three m/s will generate electricity 90 percent of the time (Wind Energy 2004). The average 750 kWh wind turbine will generate two million kWh annually (Wind Energy 2004).

Once a location has been selected, the arrangement or density will need to be determined. Since a wind turbine is generating electricity from energy in the wind, the wind speed leaving the turbine must be slower; this is called the wake effect. Due to the physical properties of energy, energy cannot be produced or consumed, only transformed. Due to the wake effect, the wind turbine slows the air speed down, and as a result, wind speeds will be slower for a wind turbine behind another wind turbine. This is called the park effect (Wind Energy 2004). To either minimize the park or wake effect, turbines are often placed in a single line.

Optimally, the wind turbines should be spaced as far apart from each other as possible in the prevailing wind direction, but due to space and cost, this is not practical or economically feasible. As a result, at wind farms, the turbines are placed about ¼ of a mile, or seven rotor lengths, apart in the prevailing wind direction. The turbines should be placed about four-rotor lengths, or 900 feet, apart in a perpendicular direction from the prevailing wind. For example, if the prevailing wind comes from the south, the turbines would be spaced ¼ of mile or seven rotor lengths, apart going north and south and about 900 feet, or four rotor lengths apart in the east-west direction (Wind Energy 2004).

The height of a turbine affects the output. As the height of a turbine is changed, the wind speed, air pressure, and air temperature alter to the height of the turbine. The first possible equation is the power law relation (Archer 2003).

$$V(z) = V_R\left(\frac{z}{z_R}\right)^{\alpha} \tag{1}$$

where $V(z)$ is the wind speed at elevation z above the ground, V_R is the wind speed at the reference or measured elevation z_R, and α is the friction of coefficient, which is typically set at $1/7$.

The second is the logarithmic law (Archer 2003)

$$V(z) = V_R \frac{\ln\left(\frac{z}{z_o}\right)}{\ln\left(\frac{z_R}{z_o}\right)} \tag{2}$$

where z_o is the roughness length, which is typically set at 0.01 meters. Both models assume neutral meteorological and atmospheric conditions, but they are simple to use and require few parameters. Below is a graph of the wind speeds from the Iowa Energy Center for Mason City, Iowa.

Table 3. Turbine height vs. Wind speed

Height (m)	Speed (m/s)
10	5.78
15	6.14
20	6.41
25	6.63
30	6.82
35	6.98
40	7.12
45	7.24
50	7.36
55	7.47
60	7.56
65	7.66
70	7.78
75	7.82
80	7.90
85	7.97
90	8.04
95	8.10
100	8.17
105	8.23
110	8.28
115	8.34

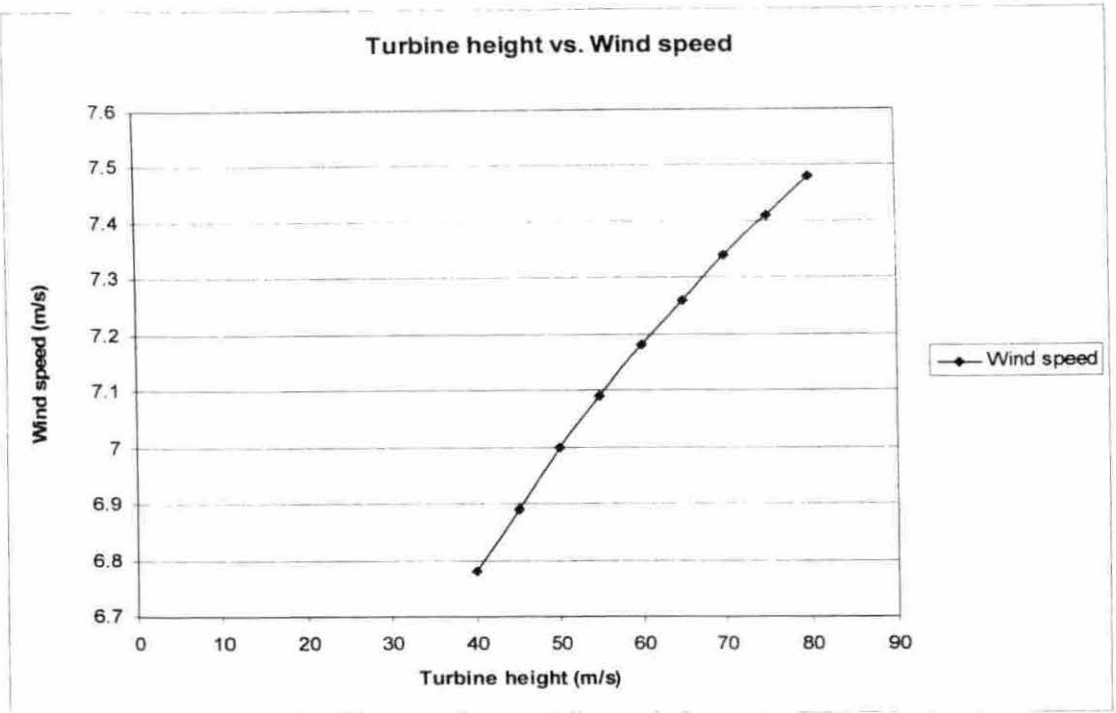

Figure 1. Turbine height vs. Wind speed

Instead of using the average wind speed, the American Wind Energy Association uses the Weibull distribution, while Archer (2003), Michael Beenstock (1995), and Renewable Resource Data Center (2003) use the Rayleigh Distribution. The Weibull or Rayleigh Distributions are thought to be more accurate at high wind speed sites. The distributions show that the wind energy is not constant and fluctuates, which determine the energy generation.

However due to environmental concerns, not all suitable sites with the necessary wind speeds may be used for wind turbine farms. One key concern of many opponents and proponents of wind turbine is the environmental impact of wind turbines. Some areas of concern involved with wind turbine farms are the killing of birds, loss of habitat for flora and fauna, and protected wildlife, especially endangered species (Rogers 25 June). Some restricted areas include national parks, monuments, wildlife refuges, wilderness areas, and other protected land. Some of the other environmental concerns are migration and nesting of birds, nearby animal habitat, nearby scientific laboratories, and the reduction of air pollutants (Adams 1986). The Environmental Protection Agency (EPA) has concluded that burning fossil fuels for energy releases two-thirds of the United State's sulfur dioxide emissions and one-third of the nation's nitrogen oxide and carbon dioxide emissions.

There is also apprehension over the aesthetics and visibility of large-scale wind farms. This issue will pose problems for the individuals who live in high-density population areas who wish to place a wind turbine on their property. For those in rural areas, it may be a more feasible source of energy. In rural or agriculture areas, there is anxiety about the destruction of landscape and current uninhibited view. In addition, legal issues such as zoning and visual aesthetics can be obstacles. Some regions have created zoning restrictions regarding the presence of wind turbines, especially utility scale turbines or wind turbine farms (AWEA 2004).

Given these restrictions, there is an estimated 6 percent of the contiguous United States, or 460,000 kilometers, that is available for wind energy production of power class 4 or higher. This land has the potential to generate 500,000 MW of electricity. Iowa has enough land area to produce 5.2 percent of the United States electricity usage (National Wind Technology Center 2003).

The National Renewable Energy Laboratory, through the Pacific Northwest Energy Lab, has conducted and completed wind energy maps for all 50 states. As a result, with the wind maps, there is an ability to derive the potential wind energy for any given site in the United States. Similarly, the Iowa Energy Center has conducted a thorough wind energy evaluation. Due to this evaluation, detailed wind speeds and wind energy output can be derived for each community and local area in the state of Iowa.

Energy Generation

It is important to remember that wind energy is not an on-demand source of energy. As a result, it must either be stored, or managed as part of an energy portfolio, such as coal, hydroelectricity, nuclear power, or natural gas. To determine the amount of electricity generated by a given wind turbine, use the following power equation (Iowa Energy Center 2004):

$$W = \frac{1}{2} \times \rho \times A \times V^3 \tag{3}$$

where W equals the number of watts (not kilowatts), A is the swept area by the rotor measured in m^2, and V is the speed of the wind calculated in m/s, usually determined from wind measuring or testing sites (Iowa Energy Center 2004). Where ρ equals air density, P equals pressure, and T equals temperature (Iowa Energy Center 2004).

$$\rho = \frac{(1.325 \times P)}{T} \tag{4}$$

The swept area of a rotor is calculated by using the equation for a circle where r is measured in meters.

$$A = \pi \times r^2 \tag{5}$$

In a similar equation by Beenstock (1995), the energy power equation is

$$E = kV^3 \tag{6}$$

with k being a technical constant, which is dependant on air pressure, size of turbine, and height of the turbine. The American Wind Energy Association defines the wind energy equation to be

$$W = \frac{(\rho \times A \times V^3 \times Ng \times Nb)}{2000} \times Cp \tag{7}$$

and when using the Beenstock method

$$k = f(\rho, A, Ng, Nb, Cp) \tag{8}$$

Each geographical site and wind turbine has different annual outputs and power curves. The annual output is determined by the hour probability distribution at a given wind speed. The Weibull or Rayleigh distribution or the mean of the wind speed is important in this case. Equation 7 assumes the wind speed is between the cut in and cut out speeds. Since the wind speed does not always flow between cut in and cut out speeds, it is important that other hours be taken into account. Wind turbines generate electricity when the wind speed exceeds the cut in speed and until the wind speed reaches the cut out speed. The cut in speed is the minimum wind speed for the wind turbine to generate electricity.

Both Ng and Nb are manufacturer constants on the generator efficiency and gearbox/bearing efficiency and are expressed as percents and where Cp is the coefficient of performance. According to the Betz Limit, theoretically, Cp can be no higher than 0.59. The Betz Limit or Betz Law was first formulated by German Albert Betz in 1919 in his book "Wind Energy" (Gripe, 152). It states that the more kinetic energy a wind turbine derives from the wind, the more wind speed will be decreased. If all the kinetic energy were extracted from the wind, the passing wind would have a speed of zero. Albert Betz determined that a maximum of 16/27 or 59 percent of the kinetic energy in the wind could be converted into mechanical energy. The limit is reached when the wind speed leaving the wind turbine is one-third of the wind speed entering the wind turbine

Financial Data

The Database of State Incentives for Renewable Energy provides information on 50 states regarding different financial incentives not only for wind energy, but also other types of renewable energy such as solar/photovoltaic, hydro, biomass, and ethanol.

Pricing

Given the nature of any commodity, the price of energy is constantly fluctuating. As mentioned earlier, the price of natural gas increased 107 percent in five months in one eastern U.S. state. Similarly, the price of energy from alternative sources may also change due to supply and demand factors. Models such as the one provided by the Danish Wind Turbine Industry Association use a single fixed price to calculate the revenue. According to Blunder, Crist, Gale, Goodale, and Wind (2004), the price will constantly fluctuate, and as a result, the models should represent a constant change in price.

Revenue

Wind energy revenue can be a part of a larger business revenue portfolio or diversification. As a result, the revenue from wind energy is a portion of the overall revenue for some entities (Blunder, Crist, and Gale 2004). For example, for investor owned utilities, wind energy may be part of a larger energy portfolio as a method to diversify and reduce risk (Blunder, Crist, and Gale 2004). This may also apply to municipal and rural electric cooperatives (Global Energy Concepts 2001). The revenue generated will be a function of the energy price and the quantity of energy (Blunder, Crist, and Gale 2004).

Construction Costs

The cost of construction includes the cost of the turbine, interconnection, transmission, and access costs, planning, legal, engineering, and administration management, and any grants provided by state or federal governments. The cost of the turbine can be $1,000 per kW (Wind Energy 2004) or higher (Blunder, Crist, and Gale 2004).

Certain entities are eligible for grants from local, state, or federal government agencies (DSIRE 2004 and Iowa Energy Center 2004). The state of Iowa allows certain not-for-profit organizations, such as schools, hospitals, and Iowa-based foundations to apply for pre-proposal funding, which are then eligible for grants for the project (Iowa Energy Center 2004)

Total Cost

There are other costs when considering the annual cost of the turbine. Some additional costs include annual operation and maintenance, annual warranty costs, annual land payment, and the annual debt service.

The annual land payments usually range from $2,000 to $4,000 (2004 USD) per turbine (Union of Concerned Scientist 2001 and Blunder, Crist, and Gale 2004). There are two different methods for land payments. In the first option, the landowner is paid a royalty fee based on the output of the turbines (Global Energy Concepts 2001). In the second option, the landowner is paid a fixed fee, which may also be adjusted for inflation. Market competition for land space from cellular phone towers, has resulted in increased land lease payments for wind turbines in recent years (Blunder, Crist, Gale, and Wind 2004).

Another cost is the operation and maintenance of the turbines. This can be calculated in four different methods. The first method is using a percent of the turbine price. The second method is using a price per kWh. The third method would be to use a fixed value. (Wind Energy 2004). The final method would be to use actual costs obtained from detailed records. Some entities may choose to contract for maintenance. In addition, turbine manufacturers may provide estimates of operation and maintenance costs.

In some cases, entities purchase warranties for the turbines. For example, Waverly Light & Power purchased a five-year warranty on the turbines at the Storm Lake Wind Facility. Larger utilities, such as investor owned utilities, might have shorter warranty periods, due to their own employees conducting operational and maintenance work (Blunder, Crist, and Gale 2004).

Each project will need a financing plan. In most instances, debt will be a part of the plan and annually require a debt service payment. Some entities will require an internal equity charge to access corporate equity from within the firm. (Blunder, Crist, and Gale 2004).

The financial costs often do not include the social costs. However, some models have compared wind energy to other forms of energy. These models do include the total costs being the construction costs, annual costs, and the social costs such, including environmental damage and national security risks (Adams 1986, Dubin 1990, Harding 1990, Hohmeyer 1990, NREL 1995, Swenson and Eathington 2002, and Wilson 1996).

Taxes

In addition to the construction and annual costs, some entities will also pay taxes at various government levels. Each industrial sector has a different tax structure. A municipality does not pay federal, state, or local income, sales, or property taxes. As result, their overall operating margin tends to be higher (Wind 2004). A rural electric cooperative

(REC) only pays the corporate income tax if more than 15 percent of their income comes from non-cooperative sources. As an REC, the tax structure allows a certain percentage to be paid as dividends to cooperative members, through which the members pay as income tax (Goodale 2004).

State and local property taxes may or may not be included in cash flow models. The Danish Wind Turbine Industry Association web site does not include this variable. The NREL site does calculate state and local property taxes. In the NREL model, the state income tax is fixed at 7.7 percent. It is unclear if it is 7.7 percent of the taxable income, or if it is 7.7 percent of federal income tax. It also has a fixed local property tax of 1 percent of the total project cost.

Many states offer some financial incentives. This may come in the form of a sales tax deduction on wind turbines, construction grants, low or no interest loans, expenditures, abatement from property taxes, and production tax credits/incentives. For example, the state of Iowa offers a local option of a graduated property tax abatement and sales tax exemption on wind energy. Iowa State Code 427.B.26 provides a graduated abatement in counties that have adopted the Wind Conversion District Ordinance. All wind turbines are applicable regardless of the owner. According to the ordinance, the abatement proceeds as follows. The local property tax is equal to the rural consolidated levy rate, which is usually valued around \$23 to \$25 per \$1,000 valuation multiplied by the assessed value (net acquisition costs or the total construction costs). For the first year, the property taxes are zero. For the second year, the property tax is five percent of the net acquisition costs. In the third year, the rate is 10 percent, the fourth year is 15 percent, the fifth year is 20 percent, the sixth year is 25 percent, and the seventh year is 30 percent. The assessed value is capped at 30 percent there after.

However, if the county does not adopt the ordinance, the turbine is taxed at 100% of the market value, instead of the schedule according to the ordinance. Knowing this, large-scale wind developers will only develop wind turbines in counties that have passed the ordinance. In addition, wind turbines are exempt from the 437A provisions of 0.0006 cents per kWh tax.

Production Tax Credit and Renewable Energy Production Incentive

Each industrial sector is eligible for a federal tax credit or incentive. A Municipal Utility (MU) and Rural Electric Cooperative (REC) (nonprofit utilities) are eligible for a Renewable Energy Production Incentive (REPI), part of the Energy Policy Act of 1992. The credit started at 1.5 cents per kWh (1993 USD) and is annually adjusted for inflation. In 2003, when the tax incentive expired, the credit was at $0.018 cents per kWh generated from renewable energy sources (Office of Power Technologies 2004). This tax incentive maybe a key component in making wind energy and other renewable energy forms cost efficient and competitive with other more conventional energy forms. However, the REPI is only applicable for the first 10 years of the turbine.

As in the REPI, the Production Tax Credit was created from the Energy Policy Act of 1992. At the end of 2003, the PTC was at $0.018 per kWh (Windustry 2004). It is also only applicable for the first 10 years of the turbine. Both IOUs and RECs are eligible for a Production Tax Credit (PTC) (Blunder, Crist, Gale, and Goodale 2004). Even if an entity qualifies for tax credits/incentives, it may not be able to take full advantage of the tax credit because the entity may not have enough passive income which is required to access the tax credit. Increasingly, wind farm developers are examining "rent seeking" scenarios where third party investors that possess sufficient tax liability are involved in the construction of wind turbines. In some states, such as Minnesota and Washington, a state PTC or REPI is available for qualifying entities. This is intended to offset the cost of wind energy production (DSIRE 2003).

The California Energy Commission compared the costs of the different types of energy and they found the benefits of the Federal Production Tax Credit (CEC 1996). The study concluded that wind energy could be competitive with other more conventional forms of energy under certain circumstances.

Table 4. Levelized fuel costs

Type of Fuel	Levelized costs (cents/kWh) (1996)
Coal	4.8-5.5
Hydro	3.9-4.4
Biomass	5.1-11.3
Nuclear	5.8-11.6
Wind (without PTC)	4.0-6.0
Wind (with PTC)	3.3-5.3

(CEC 1996)

Third Party Investment

In cases where the primary investor is not eligible or financially cannot use all of the federal tax credits, a third party investor may be involved in forming a separate business entity. An example would be for a municipality, investor owned utility, or an REC to form a Limited Liability Company (LLC) with another party, that invests a percent in the equity of the wind turbine project (Wind 2004). A possible scenario for such an investment may occur if the original investor is a non-profit entity or an entity with a small amount of federal taxable income. The third party investor would be able to use the unused amount of turbine depreciation.

Another scenario for a third party investor would be if the primary investing entity were not eligible to make complete use of eligible PTC (Wind 2004). According to the IRS code, wind turbine investors are only eligible and able to apply the production tax credits to offset passive income. By involving a third party, the PTC is more fully utilized and the potential payback period may also decrease due to the decreased amount of initial investment required by the primary investor.

The third party may involve several investors who participate in the formation of a Limited Liability Company (LLC). One consultant also suggested this business structure for use in communities where large individual investors are not available, or if the community desires to keep the financial resources and equity within the community.

Useful Life

The useful life is the life expectancy of the turbine. This is not the same as the turbine depreciation or the Turbine Finance Period. The usual life expectancy or the useful life is typically between 20 and 30 years. The National Renewable Energy Laboratory and other pro-wind energy groups suggest that wind turbines may have a life expectancy of up to 35 years. However, representatives from an investor owned utility currently planning to construct a 200+ MW wind turbine farm, indicate using a life expectancy of 15 – 20 years. The rationale was that all the electronics inside the wind turbine would likely need to be replaced with more efficient electronic components within 20 years (Blunder, Crist, and Gale 2004).

Economic Benefits

Due to the different ownership patterns and tax/incentive structures, each type of business entity will have a different impact on a community. For each set of 10 to 15 wind turbines, current industry standards are to employ one person for operation and maintenance (Global Energy Concepts 2001). The subsequent employees hired, such as operation and maintenance employees, create local economic benefits and tax revenue. This results in personal income tax for the state and federal governments. In one example, a new wind turbine farm is to be installed in northern Iowa by an investor owned utility. They expect to hire 12 employees to maintain 180 turbines for operation and maintenance. This is a ratio of one employee for every 15 turbines. From the table below, (Ritsema et al 2003) the wages for wind energy are comparable to the wages in other electrical utility sectors. In addition, these jobs have higher wages when compared to the wages in the surrounding area.

Table 5. Wages reported for selected utility sectors and farm income[1]

Job Category	Region - Area	Average Wage for Job Category & Region - Area	Percent Above or Below the Iowa Average Wage
All Jobs (2000)	Iowa	27,976	Avg. Iowa Wage
	NW	22,376	-20.0%
	NC	24,165	-13.6%
	SC	25,370	-9.3%
All Utility Jobs (2000)	Iowa	52,263	86.8%
	NW	43,705	56.2%
	NC	52,465	87.5%
	SC	46,099	64.8%
Electric Services: SIC Code 491X (2000)	US	63,819	128.1%
	Iowa	48,943	74.9%
	NW	43,736	56.3%
	NC	42,259	51.1%
	SC	36,557	30.7%
Gas Services: SIC Code 492X (2000)	US	73,268	161.9%
	Iowa	53,907	92.7%
	NW	49,555	77.1%
	NC	67,058	139.7%
	SC	26,501	-5.3%
Other Utility Services: USIC Code 493X (2000)	US	65,086	132.6%
	Iowa	53,547	91.4%
	NW	40,975	46.5%
	NC	50,391	80.1%
	SC	48,505	73.4%
Net Farm Business Income/Farm (2001)	NW	31,247	11.7%
	NC	21,053	-24.7%
	SC	20,100	-28.2%

(Iowa Workforce Development 2000)

1

NW	Northwest Iowa county cluster
NC	North Central Iowa county cluster
SC	South Central Iowa county cluster
All jobs	Average wage of all paying jobs in the region, including electric and gas utility services
All utility jobs	All paying jobs in the electric and gas utility services sector
SIC Code 491X	All paying jobs in electric power, distribution, and services sector
SIC Code 492X	All paying jobs in the gas production and distribution sector
SIC Code 493X	All paying jobs in other/ new combination utilities – electric power distribution, and services sector
Net farm business income / farm	Based on comparison of regional Farm Business Association accrual net farm income

Case Study: Waverly Light & Power

In the early 1990's, Waverly Light & Power, a municipal utility, pursued adding 4 to 7 MW of base load energy generation after 1999 (Global Energy Concepts 2001). Waverly Light & Power customers indicated that any new source energy should be environmentally friendly, even though it would be more costly than conventional forms of energy. The result was Waverly Light & Power owning two turbines at a Storm Lake Wind Facility. The site has 259 wind turbines, rated at 750 kW, and Waverly Light & Power owns two of the 50-meter rotor diameter, 65-meter tall turbines (Global Energy Concepts 2001). The capital cost of their two turbines was \$1.7 million. This would average to a little more than \$1,100 per kW. Part of the construction costs was offset by a small grant.

According to a report for Waverly Light & Power, the facility in Storm Lake, Iowa employs 25 full-time, long-term personnel to maintain the 259 turbines. Twenty-three were trained locally. In addition, more than 150 temporary jobs were created during the initial construction (Global Energy Concepts 2001). The entire project, starting with the construction of the roads, substation, and turbines until the final construction and testing was completed in about a year.

Table 6. Energy production for Waverly wind turbines for 1999

Wind Turbine	Annual Energy (kWh)	Downtime (hours)	Turbine Availability
210	2,160,151	495	94.4 %
211	2,133,195	555	93.7 %
Total	4,293,347	1093	94.0 %

Table 7 gives a first year breakdown of each turbine and the energy generated for the first year in operation. The turbine availability is the amount of time the turbines were available to generate energy. Approximately 86 percent of the time, the turbines were generating energy. The average wind speed for the first year was 7.4 meters per second. However, it was expected that the wind speed would be 7.6 meters per second.

CHAPTER 3. MODEL, METHODS, AND ASSUMPTIONS

Analysis was conducted for three different electric utility ownership structures: Investor Owned Utility (IOU), Municipality, and Rural Electric Cooperative (REC). Each industry ownership structure potentially provides different levels of benefits due to different tax treatment on local, state, and federal levels, as well as different distributions of earnings. The model will incorporate state tax and incentive structures as the baseline and enter a proxy for local taxes. The model will allow the user to input specific data about a proposed wind energy project. There will be components for construction, operation, finance, and community impact. The baseline scenario will be compared to alternative scenarios related to ownership structure and turbine size and location.

As part of the turbine assumptions, a stepwise regression, using the turbine rating was conducted to determine the wind turbine constant, for energy generation. After the regressions, a financial model was constructed. Given the variability of potential for renewable power generation, the overall revenue generation from alternative technologies will also vary. Each geographic location has the flexibility for different tax and subsidy/credit assumptions, thus leading to different conclusions for each model.

This particular model incorporates numerous financial statement characteristics. The key attributes that were considered were cost per kWh, income per kWh generated, and cumulative cash flows. In addition, cash flows are affected by state and federal government taxes and incentives. The model was generated using data from Iowa, but is intended to be applicable to states that have strong wind energy potential.

Turbine Variables

The first of set of variables defined in the spreadsheet model are the turbine data variables. It is expected that the user will have some information about the turbine, such as rotor diameter, rated output, and turbine tower height.

The rotor diameter Z_{Di} can be entered as any value. For this model, Z_{Di} was set at 60 meters for four test cases. The diameter was changed to 80 meters to show the effects of a larger wind turbine.

The rating of the turbine Z_R can also be entered as any value. For this model, the default value is set at 1000 kW. Additional simulations were conducted setting Z_R to 1500 kW to show the effects of a larger wind turbine.

The height of the turbine Z_H, which can also be entered as any value was set at a default value of 60 meters for this model. The model was simulated at both 60 meters and 80 meters. It was tested at 80 meters to show the effects of a larger turbine.

Wind Speed

The model uses maps generated by the Renewable Resource Data Center, which conducted tests to determine wind speeds at 50 meters. The Rayleigh distributions, calculated by the Renewable Resource Data Center, were used as the mean wind speed (Renewable Resources Data Center 2003). The equation below was selected due to the simplicity and for the removal of potential unknown variables. The wind speeds were estimated after the knowing the turbine height by using the equation below (Archer 2003).

$$V(z) = V_R\left(\frac{z}{z_R}\right)^{\alpha} \tag{9}$$

was modified to

$$V(z) = V_{50}\left(\frac{Z_H}{z_R}\right)^{\alpha} \tag{10}$$

where $V(z)$ is the wind speed at elevation Z_H above the ground, V_R is the wind speed at the reference or measured elevation z_R, and α is the friction of coefficient, which was set at $1/7$.

The wind maps provided the values for V_{50}. For this model, it was assumed that V_{50} was set to 7.0 meters per second for four test cases and V_{50} was set to 7.5 meters per second for an additional four test cases, using the wind speeds from Table 3 for the given altitude (Renewable Resources Data Center 2003).

$$V_m = V_{50} \times \left(\frac{Z_H}{50}\right)^{1/7} \tag{11}$$

$$V_l = V_m - 0.5 \tag{12}$$

$$V_h = V_m + 0.5 \tag{13}$$

The Renewable Resources Data Center provides wind speeds at 50 meters and equation 11 is used to determine the wind speed at heights other than 50 meters. As mentioned earlier, several different equations could have been used to determine wind speeds for given heights. Equation 11 is broad and geographically general equation and the maps only gave estimates. As a result, a model that was broader was needed to cover the potential inaccuracies of equation 11. In addition, since the wind speed is a key component in the overall revenue, three models were given for each wind speed, low, medium, and high. After an initial wind speed was calculated, the wind speed was adjusted for the variability and spatial differences within a wind class, by adjusting initial the wind speed V_i by ± 0.5 meters per second or approximately 1.1 miles per hour. This is to give an approximate energy production from a turbine for a particular spot.

Energy Generation

To determine the amount of electricity generated by a given wind turbine, the following power equation was used:

$$W = \frac{1}{2} \times \rho \times A \times V^3 \tag{14}$$

where W equals the number of watts (not kilowatts), A is the swept area by the rotor measured in m^2, and V is the speed of the wind calculated in m/s, usually determined from wind measuring or testing sites (Iowa Energy Center 2004). However, this assumes that all wind turbines have the same level of efficiency and are able to generate the same level of energy output. In this model, ρ was set at 1.22 kilograms per m^3. Equation 14 also assumes a free flowing stream of wind and that the turbine is 100% efficient. In addition, this assumes that all wind turbines have the same level of efficiency and are able to generate the same level of energy output. Since turbines are not 100% efficient, additional terms must be included. The power equation for a wind turbine is now (AWEA):

$$W = \frac{(\rho \times A \times V^3 \times Ng \times Nb)}{2000} \times Cp \tag{15}$$

In Equation 15, Ng and Nb are manufacturer constants on the generator efficiency and gearbox/bearing efficiency and are expressed as percents, where Cp is the coefficient of performance.

For this model, it was assumed that the turbine would be generating energy 90 percent of the time. Since Ng, Nb, and Cp vary on the turbine and some variables are unknown, a variable, λ is needed to be found to correct and generalize wind turbines. The variable λ is to take into account for all the unknowns of the turbine. As a result, taking Equation (15)

and substituting the values the new equation is:

$$kW = \frac{1.22 \times \left(\frac{D}{2}\right)^2 \times \pi \times V_i^3 \times 28382400}{1000} \times \lambda \tag{16}$$

A predicted λ_P was calculated by using the equation below:

$$\lambda_P = \frac{W_P}{\frac{1.22 \times \left(\frac{D}{2}\right)^2 \times \pi \times V_i^3 \times 28382400}{1000}} \tag{17}$$

By having the values of λ, a predictor for λ_P, a set of statistical regressions could be conducted. For Equation 17, W_P is based on the projected energy output from the Iowa Energy Center.

Determining λ_P

By using λ_P, it is unnecessary to determine the different wind speeds and the number of hours at each speed. The λ_P takes this into account, and removes the complexity of determining the number of hours and wind speed. The variable λ_P is determined using a statistical regression of wind turbines at different elevations from SAS. Some of the data for *this* model was generated by using estimates from the Iowa Energy Center's Wind Assessment program. The Iowa Energy Center used a formula to determine energy output given the turbine, turbine height, and the wind speed at the turbine height. All the data was analyzed for a single site in Mason City, Iowa, where a large utility wind farm currently stands. Each data point consisted of the turbine rating, turbine height, turbine rotor diameter, wind speed at that height, and estimated energy production, for a total 250 observations.

An initial regression was calculated to determine the ability to obtain a single regression equation. It was at this point that a single regression equation was not going to be adequate, and a different approach was pursued. It was determined that the turbine rating was the most significant variable in determining the wind turbine output. As a result, the wind turbine rating was broken down into four "classes." Since the energy production of a turbine is based on the rating and the number of hours, a general model was used to calculate output. As a result, four different regressions were formulated to make the model as complete as possible: small, medium, large, and utility.

The following regressions were conducted using SAS by using stepwise regression. Wind turbines with a turbine rating from 1 kW to 50 kW were measured from 10 meters to 45 meters in 5-meter intervals. The wind turbines that were rated 50 kW to 250 kW were also measured from 10 meters to 45 meters in 5-meter intervals. Wind turbines with a rating of 300 kW to 750 kW were measured from 10 meters to 85 meters in 5-meter intervals, and wind turbines with a rating from 750 kW to 2500 kW were measured from 50 meters to 115 meters at 5-meter intervals. Below is a table of default results for the model.

Table 7. Expected output from model for default values

Turbine Height (m)	Wind Speed (m/s)	Energy Production (kWh)
40	6.78	1979786
45	6.89	2042269
50	7.00	2104479
55	7.09	2155096
60	7.18	2205388
65	7.26	2249768
70	7.34	2293792
75	7.41	2331984
80	7.48	2369834

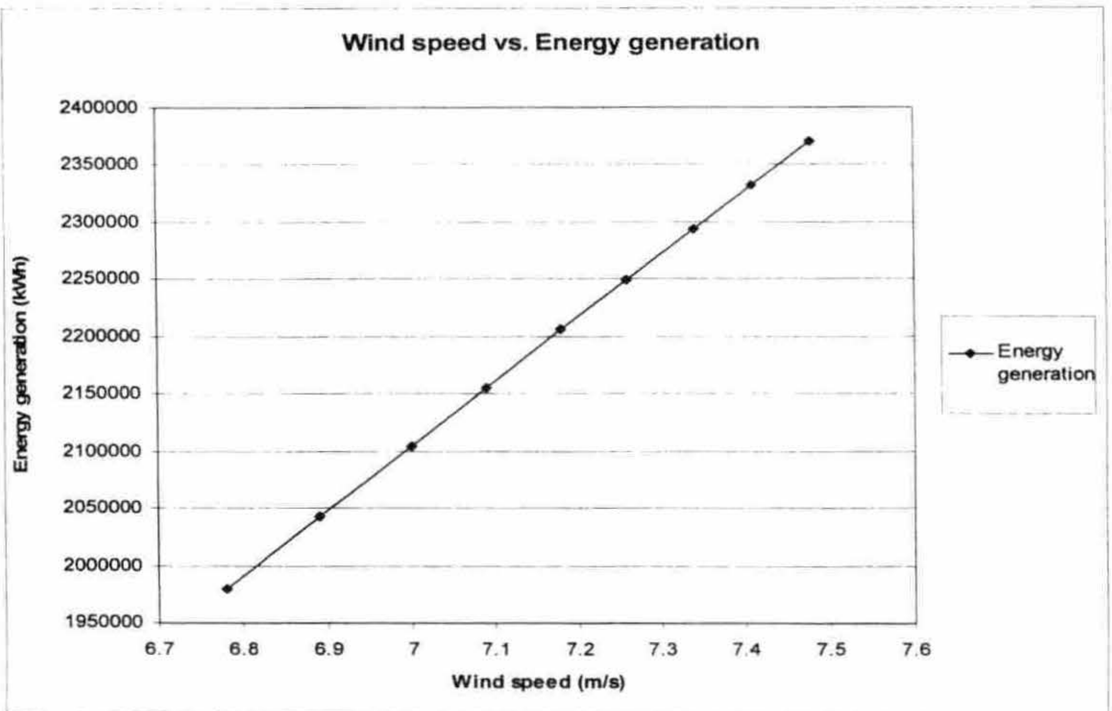

Figure 2. Wind Speed vs. Energy generation

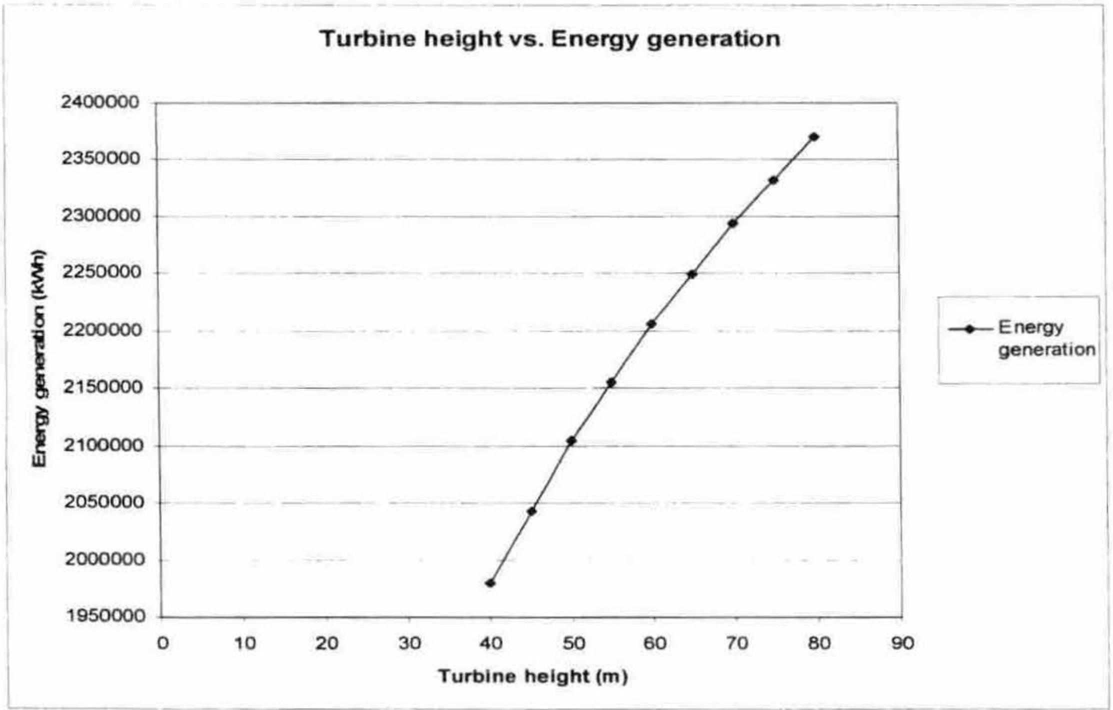

Figure 3. Turbine height vs. Energy generation

Table 8. Regression for all wind turbines

	k	rated	D	V	h
k Constant	1	0.40576 <.0001	0.43038 <.0001	0.29137 <.0001	0.29695 <.0001
rated Rated Turbine	0.40576 <.0001	1	0.94822 <.0001	0.63603 <.0001	0.66512 <.0001
D Diameter	0.43038 <.0001	0.94822 <.0001	1	0.67666 <.0001	0.70125 <.0001
V Speed	0.29137 <.0001	0.63603 <.0001	0.67666 <.0001	1	0.96432 <.0001
h Height	0.29695 <.0001	0.66512 <.0001	0.70125 <.0001	0.96432 <.0001	1

R-Square	Coeff Var	Root MSE	F-Value	Pr>F
0.376061	34.25616	0.000021	24.41	<.0001

Parameter	Estimate	Standard Error	t-value	Pr>|t|
Intercept	0.0000952409	0.00001836	5.19	<.0001
D	-0.0000027381	0.00000079	-3.47	0.0006
V	-0.0000051775	0.00000257	-2.01	0.0453
rated	0.0000002013	0.00000003	7.15	<.0001
dr	-0.0000000021	0	-1.3	0.1956
d2	0.0000000310	0.00000003	1.2	0.2317
r2	0.0000000000	0	-0.21	0.8313

$$\lambda_P = \alpha - \beta_D Z_D - \beta_{V_i} V_i + \beta_R Z_R - \beta_{DR} Z_D Z_R + \beta_{D^2} Z_D^2 + \beta_{R^2} Z_{R^2}^2 \qquad (18)$$

Table 9. Regression equation for all wind turbines

		Beta Coefficient	t-value	Pr > |t|
α	Intercept	0.0000261780	5.19	<.0001
β_D	Rotor Diameter	0.0000299787	-3.47	<.0001
β_{V_i}	Wind Speed	-0.0000096318	-2.01	<.0001
β_R	Turbine Rating	-0.0000081721	-19.08	<.0001
β_{RD}	Diameter*Rating	-0.0000000021	-1.3	0.1956
β_{D^2}	Diameter Squared	0.0000000310	1.2	0.2317
β_{R^2}	Rating Squared	0.0000000000	-0.21	0.8313

From the table above, several variables were insignificant. As a result, a better model was developed using stepwise regression. From the correlation table, the turbine rating had a correlation on 0.40576 with k, the constant. Even though the rotor diameter had a higher correlation, the turbine rating had a higher t-value, and as a result, the turbine rating was broken down in different sections, in an attempt to find a theoretical model for predicting energy output without knowing the turbine coefficients. As a result, the turbine rating was separated into four different bins: small, medium, large, and utility.

Table 10. Regression for turbines rated less than 50 kW

	k	rated	D	V	h
k Constant	1	0.52736 0.0019	0.58848 0.0004	-0.36652 0.0391	-0.3606 0.0426
rated Rated Turbine	0.52736 0.0019	1	0.99655 <.0001	0 1	0 1
D Diameter	0.58848 0.0004	0.99655 <.0001	1	0 1	0 1
V Speed	-0.36652 0.0391	0 1	0 1	1	0.98395 <.0001
h Height	-0.36056 0.0426	0 1	0 1	0.98395 <.0001	1

R-Square	Coeff Var	Root MSE	F-Value	Pr>F
0.991386	1.941292	1.25E-06	776.88	<.0001

Parameter	Estimate	Standard Error	t -value	Pr>|t|
Intercept	0.0000261780	0.0000043514	6.02	<.0001
D	0.0000299787	0.0000009304	32.22	<.0001
V	-0.0000096318	0.0000004694	-20.52	<.0001
rated	-0.0000081721	0.0000004283	-19.08	<.0001
d2	0.0000001785	0.0000000508	3.51	0.0016

For turbines where Z_R, the rated turbine is less than 50 kW, the equation is

$$\lambda = \alpha + \beta_D Z_D - \beta_{V_i} V_i - \beta_R Z_R + \beta_{D^2} Z_D^2 \tag{19}$$

Table 11. Regression equation for turbines rated less than 50 kW

		Beta Coefficient	t-value	Pr > |t|
α	Intercept	0.0000261780	6.02	<.0001
β_D	Rotor Diameter	0.0000299787	32.22	<.0001
β_{V_i}	Wind Speed	-0.0000096318	-20.52	<.0001
β_R	Turbine Rating	-0.0000081721	-19.08	<.0001
β_{D^2}	Diameter Squared	0.0000001785	3.51	0.0016

Table 12. Regression for turbines rated greater than 50 kW and less than 250 kW

	k	rated	D	V	h	d2
k Constant	1	-0.30523 0.0555	-0.58982 <.0001	-0.1611 0.3207	-0.1593 0.3262	-0.4938 0.0012
rated Rated Turbine	-0.30523 0.0555	1	0.93443 <.0001	0 1	0 1	0.97204 <.0001
D Diameter	-0.58982 <.0001	0.93443 <.0001	1	0 1	0 1	0.99164 <.0001
V Speed	-0.1611 0.3207	0 1	0 1	1	0.98395 <.0001	0 1
h Height	-0.15929 0.3262	0 1	0 1	0.98395 <.0001	1	0 1
d2 Diameter Squared	-0.4938 0.0012	0.97204 <.0001	0.99164 <.0001	0 1	0 1	1

R-Square	Coeff Var	Root MSE	F-Value	Pr>F
0.997679	1.836068	1.63E-06	2923.37	<.0001

Parameter	Estimate	Standard Error	t-value	Pr>|t|
Intercept	0.0002331700	0.0000134700	17.31	<.0001
D	-0.0000249859	0.0000012000	-20.84	<.0001
V	-0.0000106633	0.0000005500	-19.5	<.0001
rated	0.0000039582	0.0000001200	33.72	<.0001
rd	-0.0000001295	0.0000000000	-42.53	<.0001
d2	0.0000007103	0.0000000400	16.34	<.0001

For turbines where Z_R is greater than 50 kW and less than 250 kW, the equation is

$$\lambda_P = \alpha - \beta_D Z_D - \beta_{V_i} V_i + \beta_R Z_R - \beta_{RD} Z_R Z_D + \beta_{D^2} Z_D^2 \qquad (20)$$

Table 13. Regression equation for turbines rated greater than 50 kW and less than 250 kW

		Beta Coefficient	t-value	Pr > |t|
α	Intercept	0.00023317000	17.31	0.00023317000
β_D	Rotor Diameter	-0.00002498859	-20.84	-0.00002498859
β_{V_i}	Wind Speed	-0.00001066330	-19.50	-0.00001066330
β_R	Turbine Rating	0.00000395820	33.72	0.00000395820
β_{RD}	Diameter*Rating	-0.00000012950	-42.53	-0.00000012950
β_{D^2}	Diameter Squared	0.00000071030	16.34	0.00000071030

Table 14. Regression for turbines rated greater than 250 kW and less than 750 kW

	k	rated	D	V	H
k Constant	1	0.14625 0.1955	0.02739 0.8094	-0.9097 <.0001	-0.9007 <.0001
rated Rated Turbine	0.14625 0.1955	1	0.93819 <.0001	0 1	0 1
D Diameter	0.02739 0.8094	0.93819 <.0001	1	0 1	0 1
V Speed	-0.90969 <.0001	0 1	0 1	1	0.97257 <.0001
H Height	-0.90072 <.0001	0 1	0 1	0.97257 <.0001	1

R-Square	Coeff Var	Root MSE	F-Value	Pr>F
0.95536	1.763095	1.32E-06	401.28	<.0001

Parameter	Estimate	Standard Error	t-value	Pr>|t|
Intercept	0.0001792675	0.0000079243	22.62	<.0001
D	-0.0000022076	0.0000004065	-5.43	<.0001
V	-0.0000086215	0.0000002312	-37.29	<.0001
rated	0.0000000346	0.0000000026	13.51	<.0001
d2	0.0000000165	0.0000000053	3.11	0.0026

For turbines where Z_R is greater than 250 kW and less than 750 kW, the equation is

$$\lambda = \alpha - \beta_D Z_D - \beta_{V_i} V_i + \beta_R Z_R + \beta_{D^2} Z_D^2 \qquad (21)$$

Table 15. Regression equation for turbines rated greater than 250 kW and less than 750 kW

		Beta Coefficient	t-value	Pr > |t|
α	Intercept	0.0001792675	22.62	<0.0001
β_D	Rotor Diameter	-0.0000022076	-5.43	<0.0001
β_{V_i}	Wind Speed	-0.0000086215	-37.29	<0.0001
β_R	Turbine Rating	0.0000000346	13.51	<0.0001
β_{D^2}	Diameter Squared	0.0000000165	3.11	0.0026

Table 16. Regression for turbines rated greater than 750 kW

	k	rated	D	V	H
k Constant	1	0.11761 0.2488	-0.15289 0.1329	-0.72757 <.0001	-0.70465 <.0001
rated Rated Turbine	0.11761 0.2488	1	0.89668 <.0001	0 1	0.0279 0.7851
D Diameter	-0.15289 0.1329	0.89668 <.0001	1	0 1	0.03203 0.7542
V Speed	-0.72757 <.0001	0 1	0 1	1	0.98424 <.0001
H Height	-0.70465 <.0001	0.0279 0.7851	0.03203 0.7542	0.98424 <.0001	1

R-Square	Coeff Var	Root MSE	F-Value	Pr>F
0.992888	0.517533	3.63E-07	2117.45	<.0001

Parameter	Estimate	Standard Error	t-value	Pr>|t|
Intercept	0.0005694858	0.0000128000	44.48	<.0001
D	-0.0000208645	0.0000006400	-32.62	<.0001
V	-0.0000100639	0.0000001200	-82.3	<.0001
rated	0.0000004543	0.0000000100	33.38	<.0001
dr	-0.0000000050	0.0000000000	-28.56	<.0001
d2	0.0000001870	0.0000000100	-16.82	<.0001
r2	0.0000000000	0.0000000000	30.62	<.0001

For turbines where Z_R is greater than 750 kW the equation is

$$\lambda = \alpha - \beta_D Z_D - \beta_V V_i + \beta_R Z_R - \beta_{DR} Z_D Z_R + \beta_{D^2} Z_D^2 + \beta_{R^2} Z_R^2 \qquad (22)$$

Table 17. Regression for turbines rated greater than 750 kW

		Beta Coefficient	t-value	Pr > |t|
α	Intercept	0.0005694858	44.48	<0.0001
β_D	Rotor Diameter	-0.0000208645	-32.62	<0.0001
β_R	Turbine Rating	0.0000004543	33.38	<0.0001
β_{V_i}	Wind Speed	-0.0000100639	-82.30	<0.0001
β_{DR}	Diameter*Rating	-0.0000000050	-28.56	<0.0001
β_{D^2}	Diameter Squared	0.0000001870	30.62	<0.0001
β_{R^2}	Rating Squared	-0.0000000000	-16.82	<0.0001

Table 18. Comparison of regressions

	F-Value	R-Squared	Adjusted R-Squared
All	24.41	.3761	.3607
Small	776.88	.9914	.9901
Medium	2923.37	.9977	.9973
Large	401.28	.9554	.9530
Utility	2117.45	.9929	.9924

From Table 18, once the stepwise regression was completed, the R-squared value increased from 0.37 to at least 0.95. One possible explanation for this significant increase is that the regression equations are modeling the engineering calculations conducted by the Iowa Energy Center. Assuming that the energy production calculations by the Iowa Energy Center are accurate, this model would also provide an accurate model for predicting energy production without knowing the constants for the wind turbine.

Pricing

Since this model is not a pricing model, assumptions were made about actual prices. The price per kWh is the wholesale price that the electric generator will charge to the consumer or buyer of the power. Some pricing contracts vary by the minute, hour, or season. This model allows for three pricing options. Due to the unpredictable nature of the wholesale energy prices, pricing is not adjusted for inflation. One particular method may be more relevant for the user depending on the information and operating conditions that are experienced by the user.

The first pricing method that was used is representative of a flat contract rate. This approach is to define an annual average price. The user inputs a single wholesale price as dollar per kilowatt-hour ($/kWh). The annual average price ignores seasonal or daily averages.

$$p_i = p_A \tag{23}$$

The second option is a seasonal price method, where the user inputs the average seasonal and non-seasonal prices. In most geographic cases, such as Iowa, a seasonal price would be during the summer months, where there is increased demand for electricity, and a non-seasonal price would be during the winter months, where the demand is less.

$$p_i = S_r \times p_{S_P} + (1 - S_r) \times p_{S_{NP}} \tag{24}$$

The third and final option is based on a daily pricing method, where the user inputs the average daily peak and non-peak prices. A peak price would be during the daytime when businesses and households have an increased demand for electricity, while non-peak would be during the night. The daily price equation allows the user to differentiate between seasonal and daily price averages.

$$p_i = D_r \times p_{D_P} + (1 - D_r) \times p_{D_{NP}} \tag{25}$$

Revenue

Revenue is defined as the product of the energy generation by the wind turbine(s) and the price. All other business sectors and factors are ignored. The annual revenue will remain the same for all years, since this model assumes that the production and price remain the same. Since p_i is not adjusted for inflation, and the energy production does not change, the revenue will also remain constant. While three different pricing schemes can be used, for testing purposes, only the annual average pricing scheme p_A was used.

$$R = W \times p_i \quad (26)$$

$$p_i = p_A \quad (27)$$

$$\frac{\partial p_i}{\partial R} = W \times \partial p_i > 0 \quad (28)$$

Total Construction Costs

Certain assumptions were made in this study regarding economies of scale and location of projects. Economies of scale regarding the number of turbines are ignored for simplicity. However, economies of scale will likely exist as the size of the turbine increases. In some cases, when turbines are purchased for a wind farm, there is a discount in price per turbine, which decreases the cost per turbine. This discount may not apply for smaller amount of purchases. In addition, the change of location or the transportation cost of transporting the wind turbine from the manufacturing site to the actual wind turbine site is ignored.

The first cost function is the total construction cost. The total construction cost, C_{TCC} consists of three components, (1) the cost of the turbine, (2) interconnection and transmission access costs (C_I), and (3) planning, legal, engineering, and administration management (C_A). The equation for the total construction cost is:

$$C_{TCC} = Z_R \times 1300 + C_A + C_I \qquad (29)$$

Turbine costs

The first component, the cost of the turbine itself, is calculated by using the turbine rating Z_R, where it is multiplied by the constant $1,300. The cost of the turbine may include transporting the turbine to the installation site. However, it may need to be added as an engineering cost.

Interconnection and transmission access costs

The next construction cost component is the cost of connecting the wind turbine(s) to the distribution grid C_I , and the interconnection cost. This may also include access fees to the transmission lines for access to wholesale electricity markets.

Planning, legal, engineering, and administration management costs

The next component of the cost is the planning, legal, engineering, and administration management costs C_A. This is usually a one-time cost at the beginning of the decision process. This fee is usually paid to a consultant in the decision making process (Wind 2004).

Finance

The financial component includes grants, debt financing, and equity. The equity can come from a third party.

Grants received

The first component of financing the wind turbines is the grants C_G. Since each model is not eligible for grants in every state, for the baseline it was assumed that the value of the grants is zero.

Debt finance period

The debt finance is based on initial amount of debt, interest rate, and length of payments. The debt finance period C_{D_T} is the length of time, in years that the debt portion of turbine construction cost will be paid. As the length increases, the yearly payment decreases, but costs are spread over a longer period. As a result, the number of years before a firm has a positive net cash flow will also increase.

Annual debt service

The annual debt service C_{D_A} can be the largest percent of the total annual cost depending on the amount of debt financed. The determining factors include the debt repayment period and the percent of the total construction cost, C_{TCC} that is being financed by debt C_{D_p} and the interest rate for the debt, C_{D_T}. As C_{D_p} and C_{D_T} increase, the value of C_{D_A} increases.

$$C_D = C_{TCC} - E_I - C_G \tag{30}$$

$$C_{D_A} = \left(\frac{C_D \times i_D}{1 - (1 + i_D)^{-C_{D_T}}} \right) \tag{31}$$

$$\frac{\partial C_{D_T}}{\partial C_{D_A}} = -\frac{(1 + i_D)^{-C_{D_T}} (C_D + i_D) \ln(1 + i_D)}{\left(1 - (1 + i_D)^{-C_{D_T}}\right)^2} < 0 \tag{32}$$

$C_{D_T} > 0$

$$\frac{\partial i_D}{\partial C_{D_A}} = \frac{1}{1-(1+i_D)^{-C_{C_T}}} - \frac{(1+i_D)(C_D + i_D)(C_{D_T})}{\left(1-(1+i_D)^{-C_{D_T}}\right)^2} < 0 \tag{33}$$

$i_D > 0$

When the annual debt service period has been completed, there is a new plateau in cash flow. Both C_{O_A} and C_{L_A} are adjusted for inflation. As result, as long as r is not set at zero percent, the total costs or the ratio of cost per kWh will increase.

$$\frac{\partial r}{\partial C_k} = \frac{1}{W}\left(\frac{(C_O + C_L)(1-r)^{t_i} t}{r-1}\right) < 0 \tag{34}$$

$r_i \geq 1$, if there is inflation

Since the components for revenue are W and p_i, the revenue will remain the same. As long as r is greater than zero percent, the cost per kWh before taxes C_k, the cost per kWh will also increase.

$$C_k = \frac{C_T}{W}$$

(35)

Third party investment

Third party investment E_3 was assumed to be zero percent for four alternative scenarios and the third party investment was set at 30 percent for an additional four scenarios. In addition, the annual amount of passive income was set at zero for four scenarios, and then it was set at $75,000 for an additional four scenarios.

Annual Operating Costs

The total cost per year is a function of the annual operating and maintenance costs, C_{O_A}, annual warranty costs C_{W_A}, annual land payment C_{L_A}, and the annual debt service C_{D_A}.

$$C_T = C_{O_A} + C_{W_A} + C_{L_A} + C_{D_A} \tag{36}$$

Operation and maintenance

In this model, the operation and maintenance costs can be entered in two ways. The first, the method used for testing, is as a percent of the turbine rating C_{O_P}. The percent is usually between 1.5 and 4 percent (Blunder, Crist, and Gale 2004).

$$C_O = C_{O_P} \times Z_R \tag{37}$$

$$C_{O_A} = C_O \times (1 - r_i)^{t_i} \tag{38}$$

$$\frac{\partial r_i}{\partial C_{O_A}} = -C_{O_A} \times (1 - r_i)^{t-1} \times t \tag{39}$$

$r_i \geq 1$, if there is inflation

The second is with a fixed cost C_{O_F} that is adjusted for inflation.

$$C_{O_A} = C_{O_F} \times (1 - r_i)^{t_i} \tag{40}$$

$$\frac{\partial r_i}{\partial C_{O_F}} = -C_{O_F} \times (1 - r_i)^{t-1} \times t \tag{41}$$

$r_i \geq 1$, if there is inflation

Land payment

The method used in this model is with a fixed payment C_L. In this model, the land payment is adjusted for the rate of inflation, which can be controlled. This fixed payment was chosen for its simplicity and commonality.

$$C_{L_A} = C_L \times (1 - r_i)^{t_i} \tag{42}$$

$$\frac{\partial r_i}{\partial C_{L_A}} = -C_L \times (1 - r_i)^{t-1} \times t \tag{43}$$

$r_i \geq 1$, if there is inflation

Warranty

The annual warranty C_{W_A} is a fixed value as long as the warranty is in effect. The total cost of the warranty per turbine is expressed as C_W and the warranty period is expressed as C_{W_T}. The annual warranty cost is calculated using a straight-line method, as shown below.

$$C_{W_A} = \frac{C_W}{C_{W_T}} \tag{44}$$

Inflation rate and debt finance period interest rate

The inflation rate r is needed for the annual adjustment of the value for operation and maintenance and land payment. As the value of r increases, the overall costs also increase. Another component of the total cost is the interest rate for the portion of the turbine that is financed through debt i_D. As the value of i_D increases, so do the annual costs.

Taxes and Incentives

The components for taxes include the amount of turbine depreciation, federal taxes, state taxes, property taxes, and tax credits/incentives.

Turbine depreciation

The turbine depreciation period t_Z is the length of time in years that the turbine will depreciate. This length of time affects the amount of federal income tax that will be paid. If the amount of turbine depreciation Z_T is greater than C_T, the eligible amount for federal income tax will be zero. In this model, the turbine depreciation Z_T is calculated using a straight-line approach, where t_Z is the same value each year. As the number of years increase, t_Z, the value of Z_T, decreases. The exact desired value of Z_T would be dependant on the value of depreciation the entity could accommodate. If the value of accommodation was greater than the amount of turbine depreciation, then a period of depreciation should be able to decrease.

$$Z_T = \left(\frac{Z_R \times 1300}{t_Z} \right) \tag{45}$$

$$\frac{\partial Z_R}{\partial Z_T} = \frac{1300}{t_z} > 0 \tag{46}$$

$$\frac{\partial t_Z}{\partial Z_T} = -Z_R \times 1300 \left(\frac{1}{t_Z^2} \right) < 0 \tag{47}$$

Once the turbine depreciation Z_T has been calculated, an estimate of federal taxes can be calculated. If the excess depreciation T_E is greater than Z_T, then the entity has a positive balance for federal taxes. Otherwise, if T_E is less than Z_T, other entities might be pursued to increase the amount of eligible depreciation that can be used by this project. Another alternative would be to lengthen the period of turbine depreciation, which would also decrease the amount of excess depreciation for each year. When $Z_T = T_E$, net unused depreciation is zero.

Taxable federal income

Assuming that the entity is taxable, such as an investor owned utility or an REC with more than 15 percent of income from non-cooperative sources, the taxable federal corporate income tax rate structure is used to determine the federal tax liability. It is calculated as the difference between the net cash flow before taxes, I_B and the turbine depreciation, Z_T. When $Z_T > I_B$, the federal tax liability is zero.

$$T_{F_T} = I_B - Z_T \tag{48}$$

This leads to the conclusion that when the turbine depreciation, t_Z ends, the federal tax liability increases. In some examples, the federal taxable income is zero due to the turbine depreciation being greater than Net cash flow before taxes.

$Z_T > I_B$

Federal tax structure

For IOUs, and taxable RECs, the complete federal corporate tax structure is below. From the structure below, the number of turbines is relevant due to the tax income stages.

Table 19. Federal Corporate Income Tax

IRS PUB 542				
Taxable Income Over	But not over	Tax Is		Of the Amount
\$0	\$50,000		15%	\$0
\$50,000	\$75,000	\$7,500	25%	\$50,000
\$75,000	\$100,000	\$13,750	34%	\$75,000
\$100,000	\$335,000	\$22,250	39%	\$100,000
\$335,000	\$10,000,000	\$113,900	34%	\$335,000
\$10,000,000	\$15,000,000	\$3,400,000	35%	\$10,000,000
\$15,000,000	\$18,333,333	\$5,150,000	38%	\$15,000,000
\$18,333,333			35%	

State income tax

For this model, a state income tax was incorporated. It can be calculated as a percent of the taxable income (cash flow before taxes), with T_{S_p} being a constant tax rate based on the net cash flow, I_B.

$$T_S = T_{S_p} \times I_B \tag{49}$$

Alternatively, the state income tax can be a percent of the paid federal income tax, with T_{S_p} being the constant tax rate based on the paid federal income tax.

$$T_S = T_{S_p} \times T_F \tag{50}$$

Since not all states have a state income tax, the value can be set to zero percent

Property tax

The next component of taxes and incentives is a property tax. The property tax could be entered in three different methods (Harding 2004). The first, which was used for testing, is a constant valuation. Since the property tax was not adjusted for inflation, the property tax remained the same over the lifespan of the turbine. The equation for this method for calculating annual property tax is

$$T_P = \left(\frac{C_{TCC} \times T_{P_r}}{1000} \right) \tag{51}$$

with T_{P_r} being the property tax levy rate

The second method calculates property taxes using an average abatement rate, with T_{P_p} being the property tax percent abated.

$$T_P = \left(\frac{C_{TCC} \times T_{P_r}}{1000} \right)\left(1 - T_{P_p}\right) \tag{52}$$

The final method is using a property tax based on the energy production, with T_W being the tax rate per kWh of energy generated.

$$T_P = W \times T_W \tag{53}$$

Property taxes in this model are calculated using a levy rate T_{P_r} equal to \$23 per \$1,000 of the total turbine construction cost, C_{TCC}. Also included was an average annual abatement of T_{P_p} equal to 75 percent, to simulate Iowa's abatement. Since the property levy rate did not change and the rate is not adjusted for inflation, property taxes will remain the same throughout the model.

Production Tax Credit and Renewable Energy Production incentive

Both the PTC and REPI, T_C have the same values and the total value of the tax benefit T_T is calculated using the same method, by multiplying the tax credit or incentive, by the total energy production T_T.

$$T_T = T_C \times W \tag{54}$$

State PTC/REPI

Since the state of Iowa does not have a state credit/ incentive, the state tax credit/incentive T_S was assumed \$0.000 cents per kWh.

Unused PTC

If the entered value of passive income, I_P is greater than the total value of the production tax credits to be received, T_T, all the eligible tax credits are being allocated, or $I_U > 0$. However, if I_P is less than T_T, then a derived demand for finding other sources of passive income is generated to fully allocate the tax credits, or $I_U < 0$. One financial goal of the entity should be to minimize the value of unused PTC and passive income, I_U. By minimizing I_U, the entity would be maximizing their eligible tax benefits.

$$I_U = T_T - I_P \tag{55}$$

Cumulative Total and Payback Period

The income after taxes is the following equation:

$$I_A = I_B + T_T - T_F - T_S - T_P \tag{56}$$

It is equal to the cash flow before taxes plus the total tax credits or incentives minus the federal, state, and property taxes. As a result, each test case will have different values of after tax cash flow, I_A. The cumulative net cash flow after taxes I_C is calculated for the life span of the turbine.

$$I_C = \sum_{i=1}^{t_i} I_A \tag{57}$$

The payback period occurs when the cumulative cash flow after taxes I_C becomes greater than the equity investment by the primary investor. If there is a third party investor, the primary investor will have a shorter payback period because E_I has decreased with the third party investment, while the cumulative cash flow remains the same.

$$t_B = I_C > E_I \tag{58}$$

CHAPTER 4. RESULTS AND ANALYSES

A set of statistical regressions was conducted to determine the potential energy output for a wind turbine. With the regressions collected from wind turbine data, financial statements and tax data were calculated. This theoretical model allows for the simple calculation of energy generation from wind turbines and the economic costs and benefits. In addition, unlike in previous studies, an extensive financial output was developed, using more parameter than previous studies.

Base Case Models 1, 2, 3, and 4

A set of four base case models with alternative business structures and incentive policy combinations were defined and simulated.

Model 1: This is an example of an entity that is required to pay federal and state taxes and is eligible to receive the Production Tax Credit (PTC). An example would be an investor owned utility (IOU) or a Rural Electric Cooperative (REC) that is taxable with more than 15 percent of non-member revenues.

Model 2: This is an example of an entity that is does not pay federal or state taxes and is eligible to receive the Renewable Energy Production Incentive (REPI). An example would be a Municipal Utility (MU) or a Rural Electric Cooperative (REC) utility or nonprofit.

Model 3: This is an example of an entity that pays federal and state taxes and for which the PTC is not available. It is the same as Model 1 without a PTC.

Model 4: This is an example of an entity that does not pay federal or state taxes, and for which the REPI is not available. It is the same as Model 2 without a REPI.

Model 3 and Model 4 currently exist because Federal legislation authorizing the PTC and REPI has expired and new energy legislation extending the authorization has not been passed by Congress.

Scenarios A and B

For each business structure – incentive policy combination (Models 1, 2, 3, and 4) two alternative turbine size scenarios, A and B were also simulated. Below is a table that differentiates the different models. Scenario A is the baseline model. Scenario B uses larger turbine data for increased turbine output, to provide a sensitivity analysis.

Table 20. Variable definitions for Scenarios A and B

Term	Variable	'A'	'B'
Rotor Diameter	Z_{Di}	60 meters	80 meters
Turbine Height	Z_H	60 meters	80 meters
Turbine Rating	Z_R	1,000 kW	1,500 kW
Annual Price	p_i	5.5 cents/kW	5.5 cents/kW
Initial Wind Class		3	4
Medium Speed	V_m	7.18 m/s	8.02 m/s
Interconnection and Transmission Costs	C_I	$50,000	$50,000
Planning, Legal, Engineering, and Admin Mgt. Costs	C_A	$50,000	$50,000
Construction Grants	C_G	$0	$0
Total Construction Costs	C_{TCC}	$1,400,000	$2,050,000
Equity percent	E_p	40 Percent of C_{TCC}	40 Percent of C_{TCC}
3rd Party Initial Investment	E_3	0 Percent	0 Percent
Debt Financing percent	C_{D_p}	60 Percent of C_{TCC}	60 Percent of C_{TCC}
Debt Financing Period	C_{D_T}	20 Years	20 Years
Debt Financing interest rate	i_D	6 Percent	6 Percent
Inflation rate	r	3 Percent	3 Percent
Warranty	C_W	$20,000	$20,000
Warranty Period	C_{W_T}	2 Years	2 Years
O&M percent	C_{O_p}	2.5 Percent	2.5 Percent
Land Payment per year	C_L	$3,000 per turbine	$3,000 per turbine
Useful life	t_i	25 Years	25 Years
Turbine Depreciation Period	t_Z	10 Years	10 Years
Excess Depreciation	T_E	$0	$0
Passive Income	I_P	$0	$0
State income tax based Federal Income tax	T_{S_p}	10 Percent	10 Percent
Property Tax levy rate	T_{P_r}	$23/$1,000 of C_{TCC}	$23/$1,000 of C_{TCC}
Federal Tax credit per kW	T_C	1.8 cents per kWh	1.8 cents per kWh

Model 1

Table 21. Model 1– cash flow for a taxable entity receiving PTC

	Model 1A[1]		Model 1B[2]	
YEAR	Income Before Taxes	Income After Taxes	Income Before Taxes	Income After Taxes
1	$10,061.36	$17,558.36	$192,196.96	$259,570.81
2	$9,221.36	$17,909.27	$190,981.96	$261,791.52
3	$18,356.16	$27,270.71	$199,730.51	$273,298.32
4	$17,465.00	$28,642.99	$198,441.52	$275,866.96
5	$16,547.11	$29,026.43	$197,113.85	$278,512.66
6	$15,601.68	$29,421.39	$195,746.36	$281,237.73
7	$14,627.89	$29,828.19	$194,337.84	$283,812.15
8	$13,624.89	$30,247.19	$192,887.07	$286,463.80
9	$12,591.80	$30,678.77	$191,392.77	$289,195.00
10	$11,527.71	$31,123.29	$189,853.65	$292,008.14
11	$10,431.70	-$23,489.52	$188,268.35	$78,776.22
12	$9,302.81	-$24,432.15	$186,635.49	$77,843.86
13	$8,140.05	-$25,403.05	$184,853.64	$76,883.53
14	$6,942.41	-$26,403.08	$183,221.35	$75,894.39
15	$5,708.85	-$27,433.11	$181,437.08	$74,875.57
16	$4,438.27	-$28,494.04	$179,599.28	$73,826.19
17	$3,129.58	-$29,586.79	$177,706.35	$72,745.32
18	$1,781.62	-$30,712.34	$175,756.63	$71,632.03
19	$393.23	-$31,871.64	$173,748.42	$70,485.35
20	-$1,036.80	-$33,301.69	$171,679.97	$69,304.26
21	$70,725.27	$24,575.82	$276,786.46	$129,320.07
22	$69,208.14	$23,475.90	$274,592.04	$128,067.05
23	$67,745.49	$22,342.98	$272,331.78	$126,776.44
24	$66,035.96	$21,176.07	$270,003.71	$125,447.12
25	$64,378.15	$19,974.16	$267,605.80	$124,077.91
	$526,949.69	$102,124.11	$5,106,908.84	$4,157,712.40

[1] Model 1A – Investor Owned Utility (IOU) with PTC, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s
[2] Model 1B – IOU with PTC, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

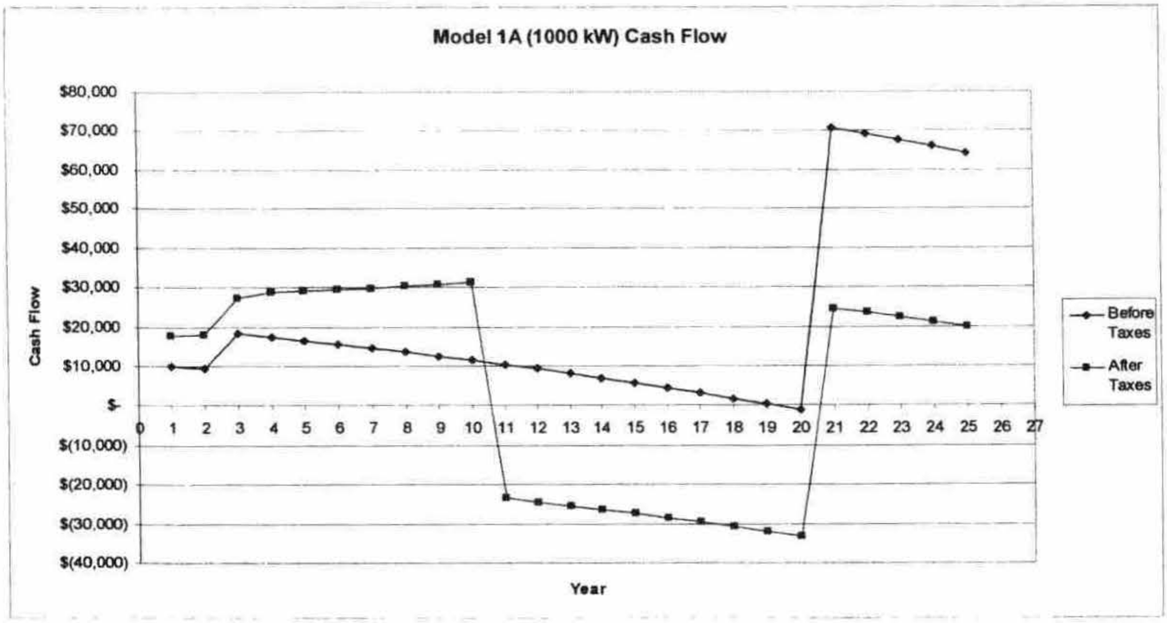

Figure 4. Model 1A (1000 kW turbine)[1] – cash flow

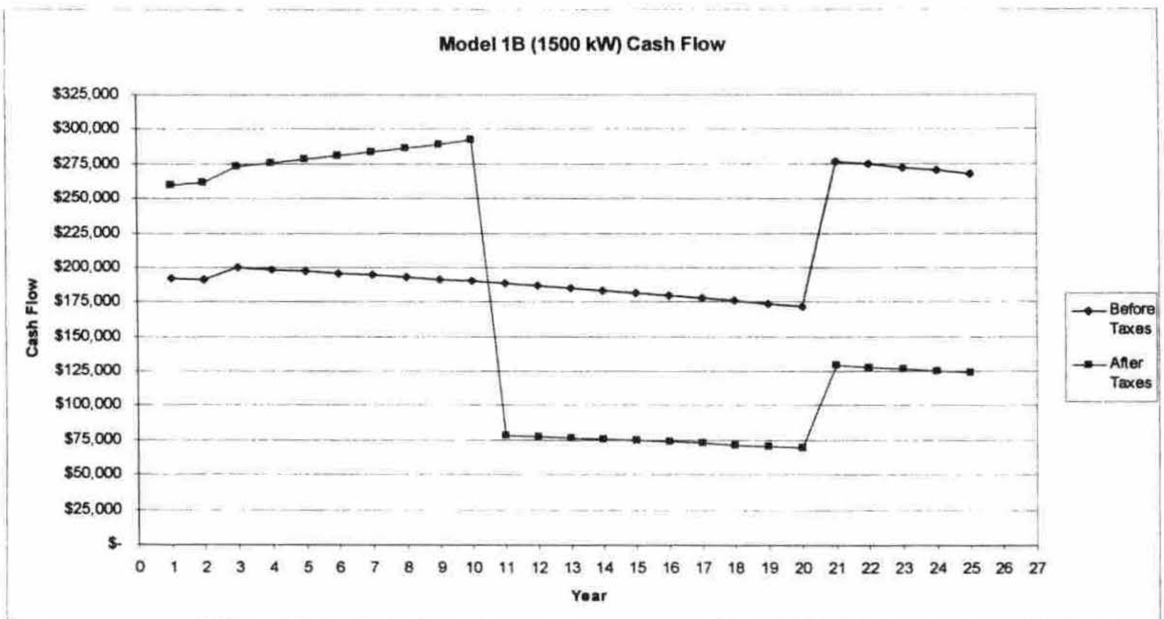

Figure 5. Model 1B (1500 kW turbine)[2] – cash flow

[1] Model 1A – Investor Owned Utility (IOU) with PTC, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 1B – IOU with PTC, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

Table 22. Model 1– financial costs and returns per kWh

	Model 1A[1]			Model 1B[2]		
YEAR	Cost[3]	Income Before Taxes	Income After Taxes[4]	Cost[5]	Income Before Taxes	Income After Taxes[6]
1	$0.0504	$0.0046	$0.0079	$0.0247	$0.03021	$0.04080
2	$0.0508	$0.0042	$0.0081	$0.0249	$0.03002	$0.04115
3	$0.0466	$0.0083	$0.0128	$0.0236	$0.03139	$0.04295
4	$0.0470	$0.0079	$0.0129	$0.0238	$0.03119	$0.04336
5	$0.0474	$0.0075	$0.0131	$0.0240	$0.03098	$0.04377
6	$0.0479	$0.0071	$0.0133	$0.0242	$0.03077	$0.04420
7	$0.0483	$0.0066	$0.0135	$0.0244	$0.03054	$0.04461
8	$0.0488	$0.0062	$0.0137	$0.0246	$0.03032	$0.04502
9	$0.0492	$0.0057	$0.0139	$0.0249	$0.03008	$0.04545
10	$0.0497	$0.0052	$0.0141	$0.0251	$0.02984	$0.04590
11	$0.0502	$0.0047	-$0.0106	$0.0254	$0.02959	$0.01238
12	$0.0507	$0.0042	-$0.0110	$0.0256	$0.02933	$0.01223
13	$0.0513	$0.0037	-$0.0115	$0.0259	$0.02905	$0.01208
14	$0.0518	$0.0031	-$0.0119	$0.0262	$0.02880	$0.01193
15	$0.0524	$0.0026	-$0.0124	$0.0264	$0.02852	$0.01177
16	$0.0529	$0.0020	-$0.0129	$0.0267	$0.02823	$0.01160
17	$0.0535	$0.0014	-$0.0134	$0.0270	$0.02793	$0.01143
18	$0.0541	$0.0008	-$0.0139	$0.0273	$0.02762	$0.01126
19	$0.0548	$0.0002	-$0.0144	$0.0276	$0.02731	$0.01108
20	$0.0554	-$0.0005	-$0.0151	$0.0280	$0.02698	$0.01089
21	$0.0229	$0.0321	$0.0111	$0.0114	$0.04350	$0.02033
22	$0.0236	$0.0314	$0.0106	$0.0118	$0.04316	$0.02013
23	$0.0243	$0.0307	$0.0101	$0.0121	$0.04280	$0.01993
24	$0.0250	$0.0299	$0.0096	$0.0125	$0.04244	$0.01972
25	$0.0258	$0.0292	$0.0090	$0.0129	$0.04206	$0.01950

[1] Model 1A – Investor Owned Utility (IOU) with PTC, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 1B – IOU with PTC, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

[3] Total costs for Model 1A– construction, financial, and annual costs

[4] Income after taxes and PTC

[5] Total costs for Model 1B– construction, financial, and annual costs

[6] Income after taxes and PTC

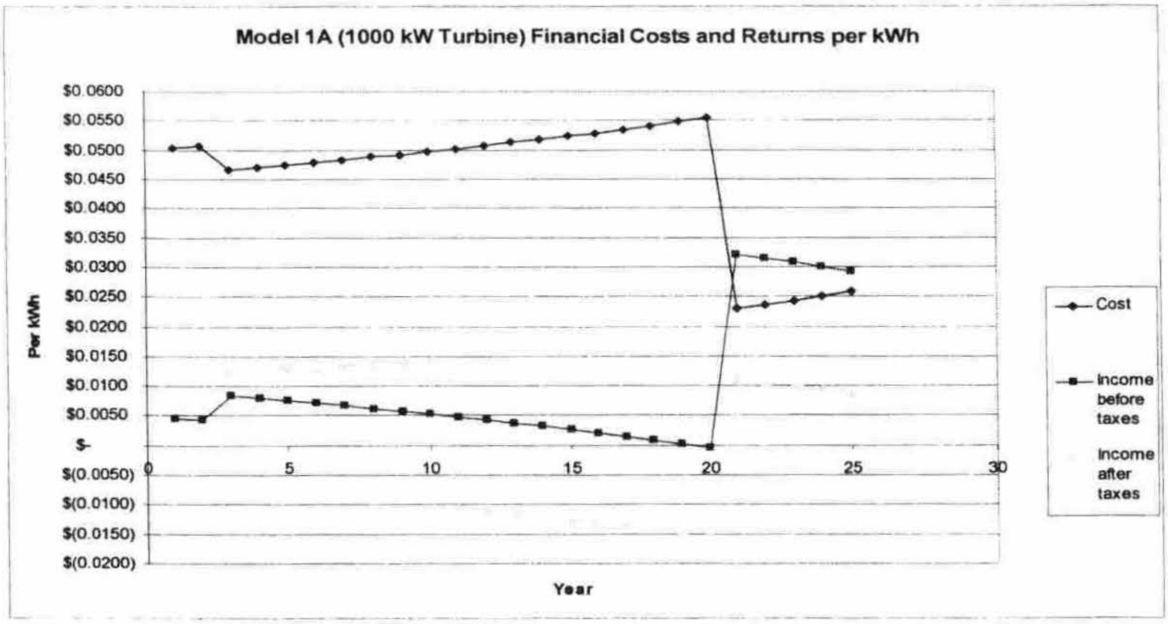

Figure 6. Model 1A (1000 kW turbine)[1] – financial costs and returns per kWh

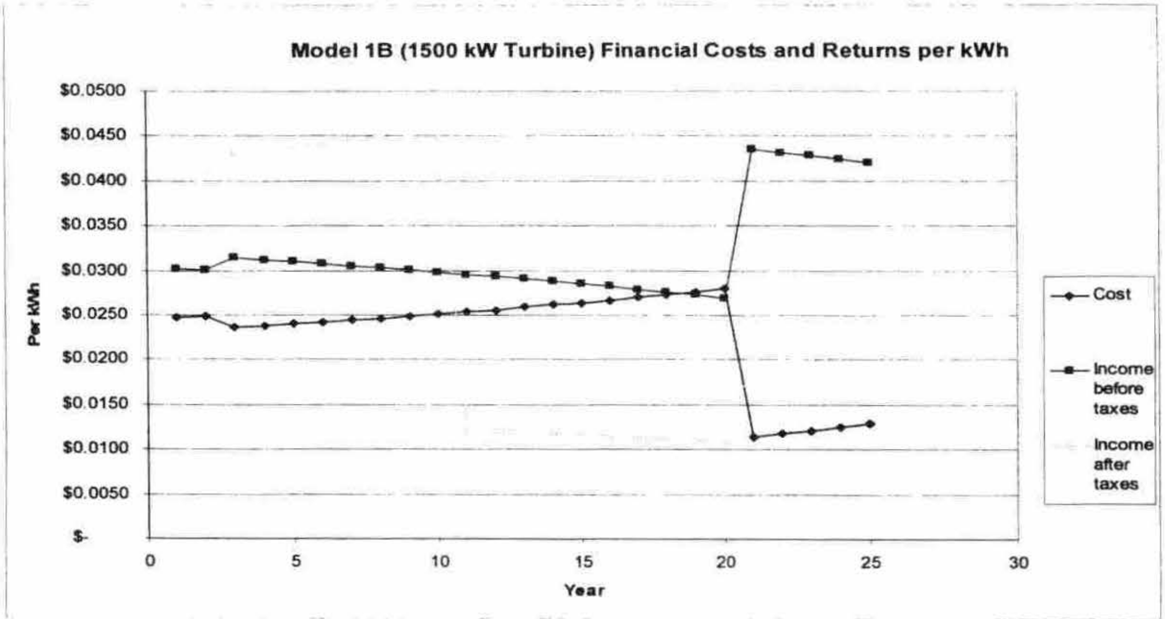

Figure 7. Model 1B (1500 kW turbine)[2] – financial costs and returns per kWh

[1] Model 1A – Investor Owned Utility (IOU) with PTC, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s
[2] Model 1B – IOU with PTC, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

Model 1 is an example of an entity that is required to pay federal and state taxes and is eligible to receive the Production Tax Credit (PTC). An example of this model would be an investor owned utility or a Rural Electric Cooperative that is taxable with more than 15 percent non-member revenues. In addition, it is assumed that the federal and state income tax is only being applied to the net cash flow from the wind energy revenue.

The differences in 1A and 1B are in the assumptions regarding the wind turbine. Model 1A uses a wind turbine with a 60-meter rotor diameter, placed at a height of 60 meters, rated at 1,000 kW, and with an initial Wind Class of 3. Model 1B uses a wind turbine with an 80-meter rotor diameter, placed at a height of 80 meters, rated at 1,500 kW, and placed at a site with an initial Wind Class of 4. All other financial variables remained the same. The reasoning for analyzing these two models is to show the effects of turbine size on taxes and tax credits. With negative cash flows, the income tax would be zero. Both 1A and 1B follow the same cash flow patterns.

In year two, the warranty expires, which results in an increase in the net cash flow comparing year two to year three. In Model 1A, the turbine depreciation was greater than the net cash flow with $Z_T > I_B$, resulting in the federal taxable income to be zero. However, in Model 1B, $Z_T < I_B$, resulting in a positive federal taxable income. During the first 10 years, the entity is receiving a Production Tax Credit based on the energy generation from the wind turbine. Since the energy generation is greater in Model 1B than Model 1A, Model 1B shows a higher level of tax credits. The Federal tax credit expires after 10 years (Office of Power Technologies 2004). From year 11 to year 20, the entity is still financing debt, but not receiving a tax credit. In Model 1A, this results in a negative cash flow after the taxes, while Model 1B has a decreased, yet positive cash flow. In addition, during this period, due to the negative taxable federal income, the Federal income tax liability is zero. In year 20, for Model 1A, the costs exceed the revenue with $C_T > R$. In year 20, the debt-financing period has been completed, and as a result, both models have positive net cash flows. Due to the positive inflation, $r > 0$, cost is an upward sloping function. Since revenue R remains constant, due to both p_i and W remaining the same, the cash flows before and after taxes are downward sloping.

The cumulative cash flow is the summation of net cash flow after taxes $t_B > 25$. For Model 1A, the initial equity is never recovered. However, the payback period for Model 1B occurs when $t_B = 4$.

Model 2

Table 23. Model 2 – cash flow for a nonprofit entity not paying federal, state, or property taxes and receiving REPI

	MODEL 2A[1]		MODEL 2B[2]	
Year	Income Before Incentives	Income After Incentives	Income Before Incentives	Income After Incentives
1	$10,061.36	$49,758.36	$192,196.96	$306,720.81
2	$9,221.36	$50,109.27	$190,981.96	$308,941.52
3	$18,356.16	$60,470.71	$199,730.51	$321,228.86
4	$17,465.00	$60,842.99	$198,441.52	$323,584.81
5	$16,547.11	$61,226.43	$197,113.85	$326,011.45
6	$15,601.68	$61,621.39	$195,746.36	$328,510.88
7	$14,627.89	$62,028.19	$194,337.84	$331,085.30
8	$13,624.89	$62,447.19	$192,887.07	$333,736.95
9	$12,591.80	$62,878.77	$191,392.77	$336,468.15
10	$11,527.71	$63,323.29	$189,853.65	$339,281.29
11	$10,431.70	$10,431.70	$188,268.35	$188,268.35
12	$9,302.81	$9,302.81	$186,635.49	$186,635.49
13	$8,140.05	$8,140.05	$184,853.64	$184,953.64
14	$6,942.41	$6,942.41	$183,221.35	$183,221.35
15	$5,708.85	$5,708.85	$181,437.08	$181,437.08
16	$4,438.27	$4,438.27	$179,599.28	$179,599.28
17	$3,129.58	$3,129.58	$177,706.35	$177,706.35
18	$1,781.62	$1,781.62	$175,756.63	$175,756.63
19	$393.23	$393.23	$173,748.42	$173,748.42
20	-$1,036.80	-$1,036.80	$171,679.97	$171,679.97
21	$70,725.27	$70,725.27	$276,786.46	$276,786.46
22	$69,208.14	$69,208.14	$274,592.04	$274,592.04
23	$67,745.49	$67,645.49	$272,331.78	$272,331.78
24	$66,035.96	$66,035.96	$270,003.71	$270,003.71
25	$64,378.15	$ 4,378.15	$267,605.80	$267,605.80
	$526,949.69	$981,931.32	$5,106,908.84	$6,419,896.37

[1] Model 2A – Municipal Utility (MU) with REPI, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s
[2] Model 2B – MU with REPI, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

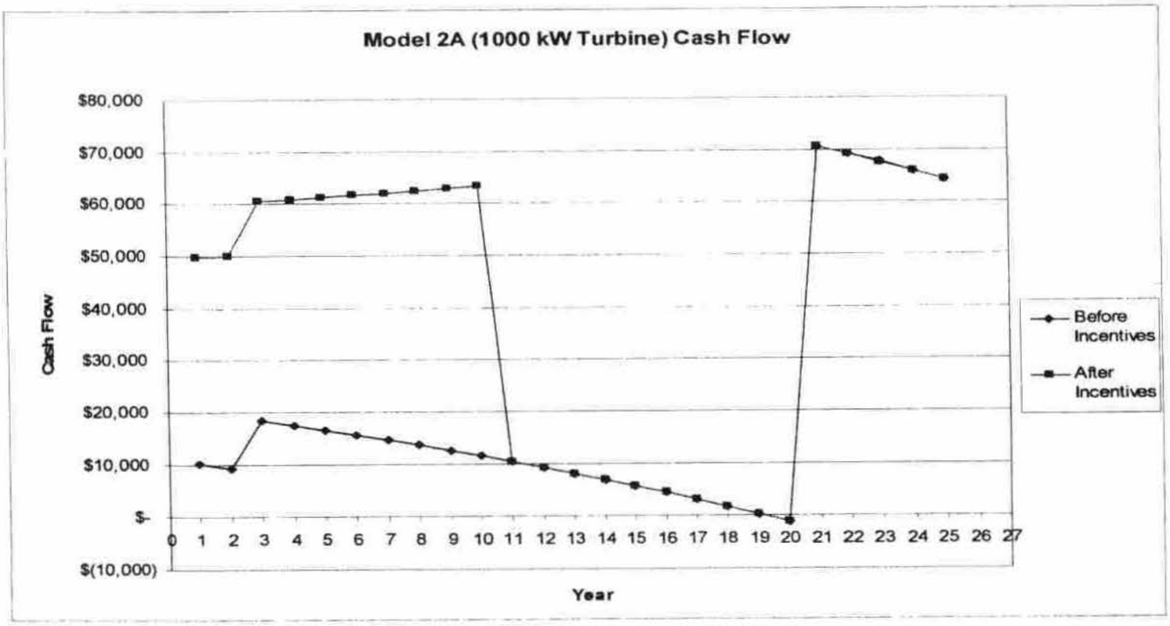

Figure 8. Model 2A (1000 kW turbine)[1] – cash flow

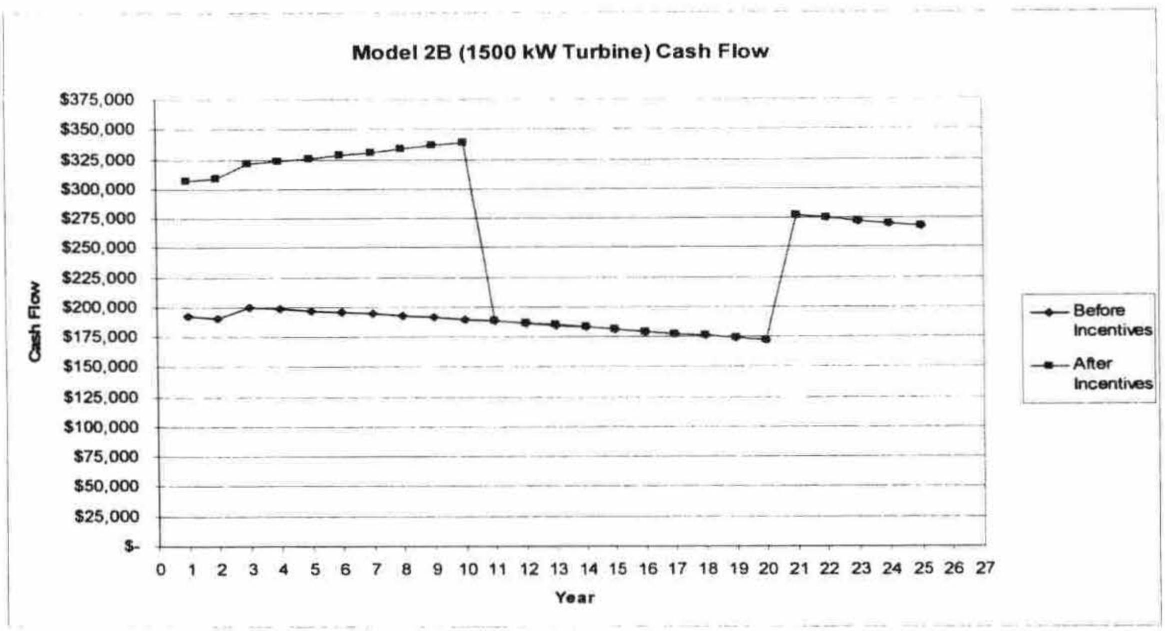

Figure 9. Model 2B (1500 kW turbine)[2] – cash flow

[1] Model 2A – Municipal Utility (MU) with REPI, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 2B – MU with REPI, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

Table 24. Model 2 – financial costs and returns per kWh

	MODEL 2A[1]			MODEL 2B[2]		
Year	Cost[3]	Income Before Incentives	Income After Incentives[4]	Cost[5]	Income Before Incentives	Income After Incentives[6]
1	$0.0504	$0.0046	$0.0225	$0.0247	$0.03021	$0.04820
2	$0.0508	$0.0042	$0.0227	$0.0249	$0.03002	$0.04850
3	$0.0466	$0.0083	$0.0274	$0.0236	$0.03139	$0.05040
4	$0.0470	$0.0079	$0.0275	$0.0238	$0.03119	$0.05080
5	$0.0474	$0.0075	$0.0277	$0.0240	$0.03098	$0.05120
6	$0.0479	$0.0071	$0.0279	$0.0242	$0.03077	$0.05160
7	$0.0483	$0.0066	$0.0281	$0.0244	$0.03054	$0.05200
8	$0.0488	$0.0062	$0.0283	$0.0246	$0.03032	$0.05240
9	$0.0492	$0.0057	$0.0285	$0.0249	$0.03008	$0.05280
10	$0.0497	$0.0052	$0.0287	$0.0251	$0.02984	$0.05330
11	$0.0502	$0.0047	$0.0047	$0.0254	$0.02959	$0.02959
12	$0.0507	$0.0042	$0.0042	$0.0256	$0.02933	$0.02933
13	$0.0513	$0.0037	$0.0037	$0.0259	$0.02905	$0.02905
14	$0.0518	$0.0031	$0.0031	$0.0262	$0.02880	$0.02880
15	$0.0524	$0.0026	$0.0026	$0.0264	$0.02852	$0.02852
16	$0.0529	$0.0020	$0.0020	$0.0267	$0.02823	$0.02823
17	$0.0535	$0.0014	$0.0014	$0.0270	$0.02793	$0.02793
18	$0.0541	$0.0008	$0.0008	$0.0273	$0.02762	$0.02762
19	$0.0548	$0.0002	$0.0002	$0.0276	$0.02731	$0.02731
20	$0.0554	-$0.0005	-$0.0005	$0.0280	$0.02698	$0.02698
21	$0.0229	$0.0321	$0.0321	$0.0114	$0.04350	$0.04350
22	$0.0236	$0.0314	$0.0314	$0.0118	$0.04316	$0.04316
23	$0.0243	$0.0307	$0.0307	$0.0121	$0.04280	$0.04280
24	$0.0250	$0.0299	$0.0299	$0.0125	$0.04244	$0.04244
25	$0.0258	$0.0292	$0.0292	$0.0129	$0.04206	$0.04206

[1] Model 2A – Municipal Utility (MU) with REPI, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 2B – MU with REPI, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

[3] Total costs for Model 2A– construction, financial, and annual costs

[4] Income after REPI

[5] Total costs for Model 2B– construction, financial, and annual costs

[6] Income after REPI

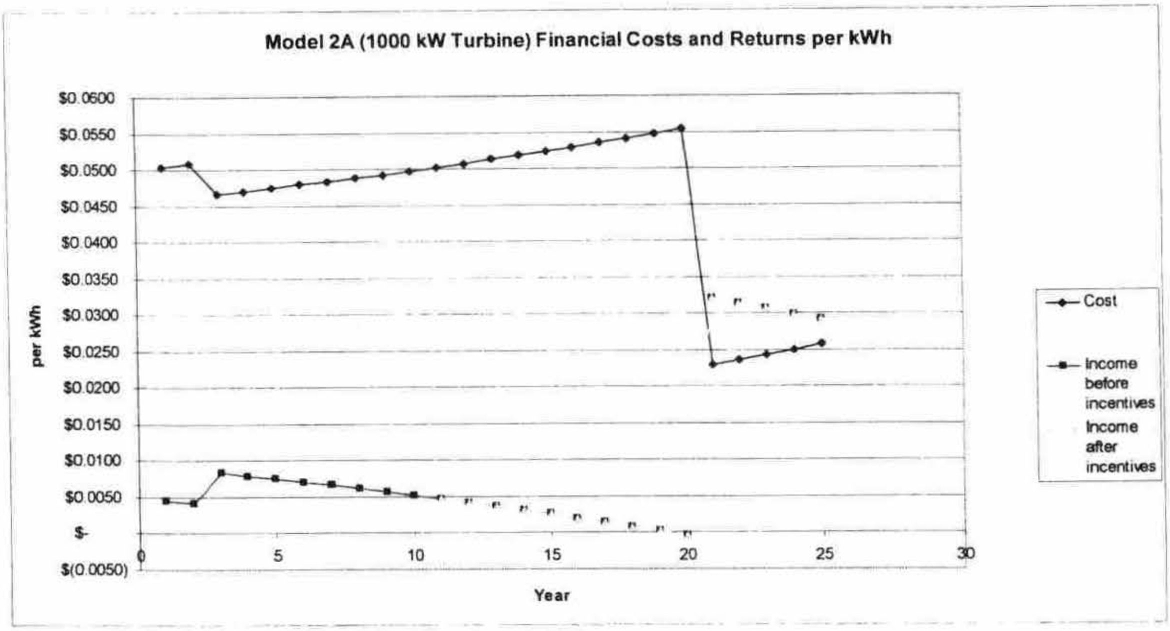

Figure 10. Model 2A (1000 kW turbine)[1] – financial costs and returns per kWh

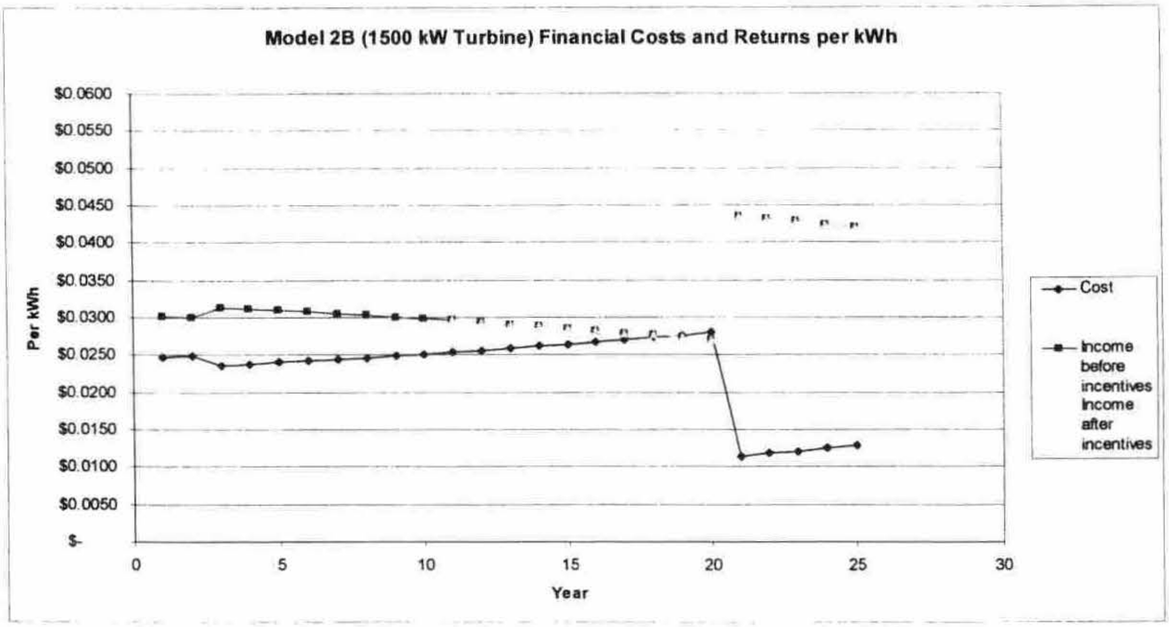

Figure 11. Model 2B (1500 kW turbine)[2] – financial costs and returns per kWh

[1] Model 2A – Municipal Utility (MU) with REPI, based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s
[2] Model 2B – MU with REPI, based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

Model 2 is an example of an entity that is does not pay federal or state taxes and is eligible to receive the Renewable Energy Production Incentive (REPI). An example of this model would be a Municipal Utility (MU) or some other nonprofit entity that is not taxable, such as a Rural Electric Cooperative with less than 15 percent non-member income. In this model the entity does not pay federal, state income taxes, or property taxes. In the case of a municipal government, it is eligible for a Renewable Energy Production Incentive (REPI) (Office of Power Technologies 2004).

The differences in 2A and 2B are in the assumptions of the wind turbine. Model 2A uses a wind turbine with a 60-meter rotor diameter, placed at a height of 60 meters, rated at 1,000 kW, and with an initial Wind Class of 3. Model 2B uses a wind turbine with an 80-meter rotor diameter, placed at a height of 80 meters, rated at 1,500 kW, and placed at a site with an initial Wind Class of 4. All other financial variables remained the same.

In year two, the warranty expired, which resulted in an increase in the net cash flow from year two to year three. The next plateau is from year 10 and year 11, with the expiration of the REPI (Office of Power Technologies 2004). In Model 2A, the turbine depreciation remains unused as a nonprofit entity, but it would have been greater than the net cash flow, with $Z_T > I_B$. However, in Model 2B, $Z_T < I_B$. Since the energy generation is greater in Model 2B than Model 2A, 2B has increased REPI. From year 11 to year 20, the entity is still financing debt, but not receiving the REPI. In Model 2A, this results in a negative cash flow, while Model 2B has a decreased, yet positive cash flow. In year 20, for Model 2A, the costs exceed the revenue with $C_T > R$. After year 20, the debt-financing period has been completed, and as a result, both models have positive net cash flows.

In addition, in Model 2A the equity is never recovered, where the cumulative cash flow is the summation of net cash flow after taxes. Due to the positive inflation, $r > 0$, cost is an upward sloping function, shown in Figures 10 and 11. Since revenue R remains constant, due to both p_i and W remaining the same. As a result, the payback period is greater than 25 years, which is longer than the expected life span of the wind turbine with $t_B > 25$. However, the payback period for the larger wind turbine at a site with a higher average wind speed, the payback period is year four, even with the higher initial turbine costs, due to the increased REPI received, with $t_B = 4$.

Model 3

Table 25. Model 3 – cash flow for a taxable entity that does not receiving a PTC

	MODEL 3A[1]		MODEL 3B[2]	
YEAR	Income Before Taxes	Income After Taxes	Income Before Taxes	Income After Taxes
1	$10,061.36	-$22,138.63	$192,196.96	$145,046.96
2	$9,221.36	-$22,978.63	$190,981.96	$143,831.96
3	$18,356.16	-$13,843.83	$199,730.51	$151,799.98
4	$17,465.00	-$14,734.99	$198,441.52	$150,723.67
5	$16,547.11	-$15,652.88	$197,113.85	$149,615.07
6	$15,601.68	-$16,498.31	$195,746.36	$148,473.21
7	$14,627.89	-$17,572.10	$194,337.84	$147,064.69
8	$13,624.89	-$18,575.10	$192,887.07	$145,613.92
9	$12,591.80	-$19,608.19	$191,392.77	$144,119.62
10	$11,527.71	-$20,672.28	$189,853.65	$142,580.50
11	$10,431.70	-$23,489.53	$188,268.35	$78,776.22
12	$9,302.81	-$24,432.15	$186,635.49	$77,843.86
13	$8,140.05	-$25,403.05	$184,853.64	$76,883.53
14	$6,942.41	-$26,403.08	$183,221.35	$75,894.39
15	$5,708.85	-$27,433.11	$181,437.08	$74,875.57
16	$4,438.27	-$28,484.04	$179,599.28	$73,826.19
17	$3,129.58	-$29,586.79	$177,706.35	$72,745.32
18	$1,781.62	-$30,712.34	$175,756.63	$71,632.03
19	$393.23	-$31,871.64	$173,748.42	$70,485.35
20	-$1,036.80	-$33,301.69	$171,679.97	$69,304.26
21	$70,725.27	$24,575.82	$276,786.46	$129,320.07
22	$69,208.14	$23,475.90	$274,592.04	$128,067.05
23	$67,745.49	$22,342.98	$272,331.78	$126,776.44
24	$66,035.96	$21,176.07	$270,003.71	$125,447.12
25	$64,378.15	$19,974.16	$267,605.80	$124,077.91
	$526,949.69	-$351,847.43	$5,106,908.84	$2,844,824.89

[1] Model 3A – Investor Owned Utility (IOU) based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s, without PTC

[2] Model 3B – IOU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s, without PTC

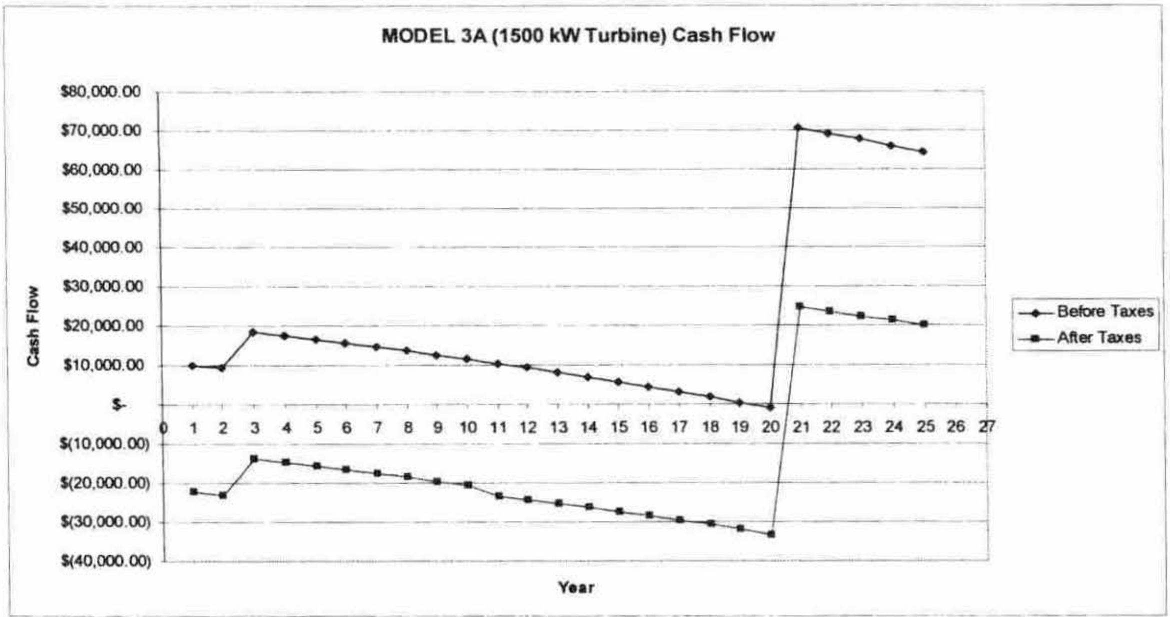

Figure 16. Model 3A (1000 kW turbine)[1] – cash flow

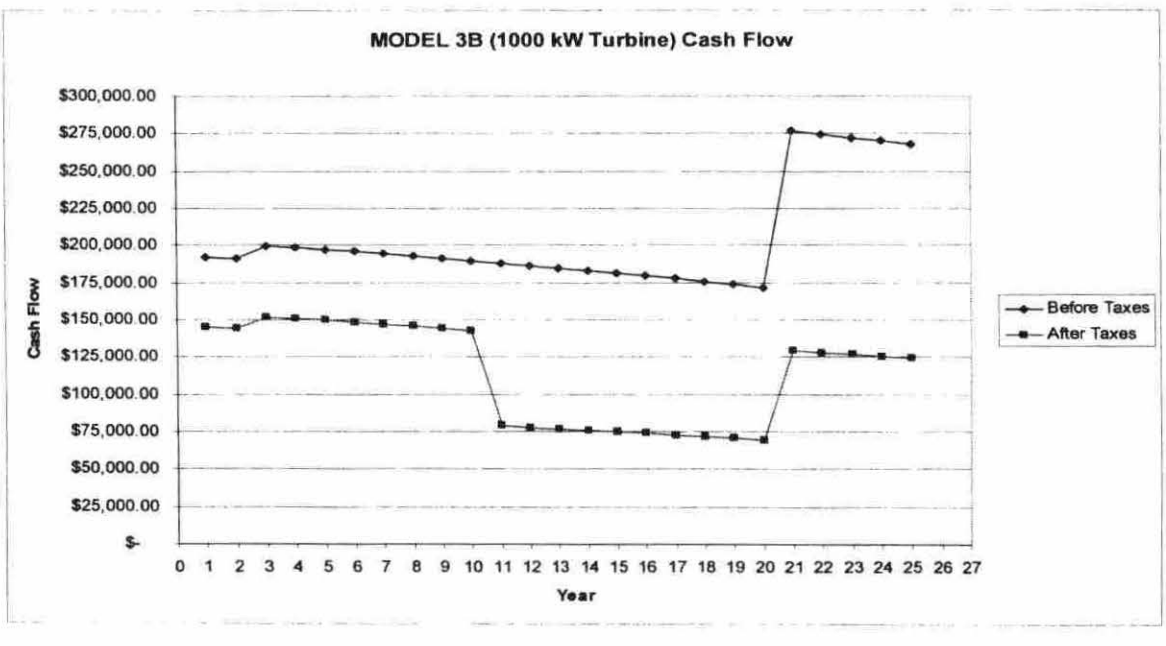

Figure 17. Model 3B (1500 kW turbine)[2] – cash flow

[1] Model 3A – Investor Owned Utility (IOU) based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s, without PTC

[2] Model 3B – IOU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s, without PTC

Table 26. Model 3 – financial costs and returns per kWh

	MODEL 3A[1]			MODEL 3B[2]		
Year	Cost[3]	Income Before Taxes	Income After Taxes[4]	Cost[5]	Income Before Taxes	Income After Taxes[6]
1	$0.0504	$0.0046	-$0.0100	$0.0247	$0.03021	$0.02280
2	$0.0508	$0.0042	-$0.0104	$0.0249	$0.03002	$0.02261
3	$0.0466	$0.0083	-$0.0062	$0.0236	$0.03139	$0.02386
4	$0.0470	$0.0079	-$0.0066	$0.0238	$0.03119	$0.02369
5	$0.0474	$0.0075	-$0.0070	$0.0240	$0.03098	$0.02352
6	$0.0479	$0.0071	-$0.0075	$0.0242	$0.03077	$0.02334
7	$0.0483	$0.0066	-$0.0079	$0.0244	$0.03054	$0.02311
8	$0.0488	$0.0062	-$0.0084	$0.0246	$0.03032	$0.02289
9	$0.0492	$0.0057	-$0.0088	$0.0249	$0.03008	$0.02265
10	$0.0497	$0.0052	-$0.0093	$0.0251	$0.02984	$0.02241
11	$0.0502	$0.0047	-$0.0106	$0.0254	$0.02959	$0.01238
12	$0.0507	$0.0042	-$0.0110	$0.0256	$0.02933	$0.01223
13	$0.0513	$0.0037	-$0.0115	$0.0259	$0.02905	$0.01208
14	$0.0518	$0.0031	-$0.0119	$0.0262	$0.02880	$0.01193
15	$0.0524	$0.0026	-$0.0124	$0.0264	$0.02852	$0.01177
16	$0.0529	$0.0020	-$0.0129	$0.0267	$0.02823	$0.01160
17	$0.0535	$0.0014	-$0.0134	$0.0270	$0.02793	$0.01143
18	$0.0541	$0.0008	-$0.0139	$0.0273	$0.02762	$0.01126
19	$0.0548	$0.0002	-$0.0144	$0.0276	$0.02731	$0.01108
20	$0.0554	-$0.0005	-$0.0151	$0.0280	$0.02698	$0.01089
21	$0.0229	$0.0321	$0.0111	$0.0114	$0.04350	$0.02033
22	$0.0236	$0.0314	$0.0106	$0.0118	$0.04316	$0.02013
23	$0.0243	$0.0307	$0.0101	$0.0121	$0.04280	$0.01993
24	$0.0250	$0.0299	$0.0096	$0.0125	$0.04244	$0.01972
25	$0.0258	$0.0292	$0.0090	$0.0129	$0.04206	$0.01950

[1] Model 3A – Investor Owned Utility (IOU) based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s
[2] Model 3B – IOU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s
[3] Total costs for Model 3A– construction, financial, and annual costs
[4] Income after taxes
[5] Total costs for Model 3B– construction, financial, and annual costs
[6] Income after taxes

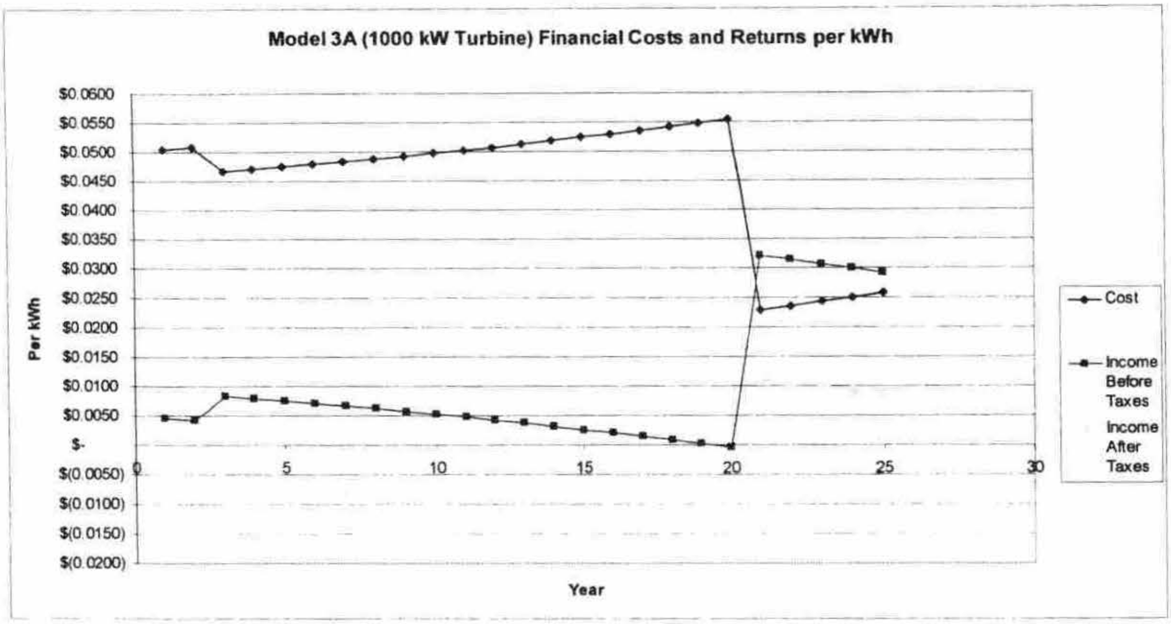

Figure 18. Model 3A (1000 kW turbine)[1] – financial costs and returns per kWh

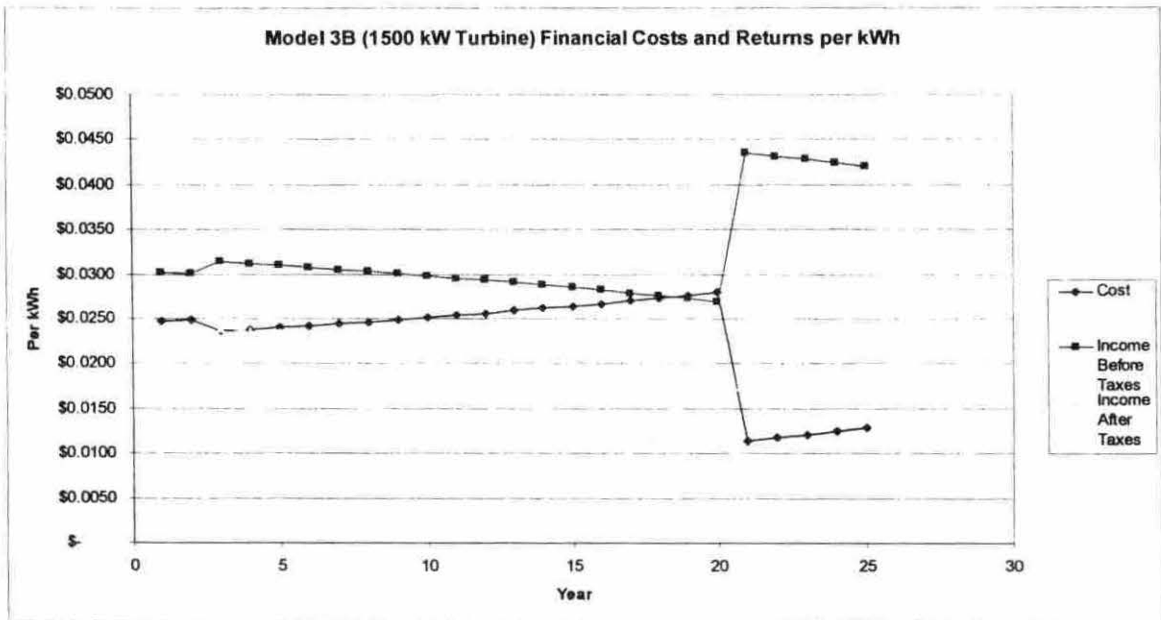

Figure 19. Model 3B (1500 kW turbine)[2] – financial costs and returns per kWh

[1] Model 3A – Investor Owned Utility (IOU) based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 3B – IOU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

Model 3 is an example of an entity that pays federal or state taxes and for which there is no Production Tax Credit (PTC) available. An example of this model would be a taxable entity, such as an Investor Owned Utility (IOU) or a Rural Electric Cooperative (REC). This model is to show the economic impact of the loss of tax credits/incentives for wind energy.

The differences in Model 3A and Model 3B are in the assumptions in the wind turbine. Model 3A uses a wind turbine with a 60-meter rotor diameter, placed at a height of 60 meters, rated at 1,000 kW, and with an initial Wind Class of 3. Model 3B uses a wind turbine with an 80-meter rotor diameter, placed at a height of 80 meters, rated at 1,500 kW, and placed at a site with an initial Wind Class of 4. All other financial variables remained the same. Model 3B was created for comparison purposes to other models. Due to the change in turbine and turbine location, there will be increased energy production.

In year two, the warranty is no longer in effect, which results in an increase in the net cash flow from year two to year three. The next plateau is from year 10 and year 11. In Model 3A, the turbine depreciation remains greater than the net cash flow with $Z_T > I_B$, resulting in a federal taxable income of zero. However, in 3B. From year 11 to year 20, the entity is still financing debt. In Model 3A, this results in a negative cash flow after the taxes, while Model 3B has a decreased, yet positive cash flow. In addition, during this period, due to the negative taxable federal income, the federal income tax liability is zero. Only in year 20, for Model 3A, do the costs exceed the revenue with $C_T > R$. Due to the positive inflation rate, the net losses continue increasing. After year 20, the debt-financing period has been completed, and as a result, both models begin to experience positive net cash flows. Only after the debt-financing period has been completed does Model 3A have a positive net cash flow after taxes. Due to the positive inflation, $r > 0$, cost is an upward sloping function.

Since revenue R remains constant, due to both p_i and W remaining the same, the cash flows before and after taxes slope downward

In addition, in Model 3A the initial debt payment is never fully recovered. The payback period is greater than 25 years, which is longer than the assumed expected life span of the wind turbine with $t_B > 25$. However, the payback period for Model 3B, the payback period is when $t_B = 6$.

Model 4

Table 27. Model 4 - cash flow for a nonprofit entity not paying federal, state, or property taxes and not receiving REPI

	MODEL 4A[1]		MODEL 4B[2]	
YEAR	Income Before Taxes	Income After Taxes	Income Before Taxes	Income After Taxes
1	$10,061.36	$10,061.36	$192,196.96	$192,196.96
2	$9,221.36	$9,221.36	$190,981.96	$190,981.96
3	$18,356.16	$18,356.16	$199,730.51	$199,730.51
4	$17,465.00	$17,465.00	$198,441.52	$198,441.52
5	$16,547.11	$16,547.11	$197,113.85	$197,113.85
6	$15,601.68	$15,601.68	$195,746.36	$195,746.36
7	$14,627.89	$14,627.89	$194,337.84	$194,337.84
8	$13,624.89	$13,624.89	$192,887.07	$192,887.07
9	$12,591.80	$12,591.80	$191,392.77	$191,392.77
10	$11,527.71	$11,527.71	$189,853.65	$189,853.65
11	$10,431.70	$10,431.70	$188,268.35	$188,268.35
12	$9,302.81	$9,302.81	$186,635.49	$186,635.49
13	$8,140.05	$8,140.05	$184,853.64	$184,853.64
14	$6,942.41	$6,942.41	$183,221.35	$183,221.35
15	$5,708.85	$5,708.85	$181,437.08	$181,437.08
16	$4,438.27	$4,438.27	$179,599.28	$179,599.28
17	$3,129.58	$3,129.58	$177,706.35	$177,706.35
18	$1,781.62	$1,781.62	$175,756.63	$175,756.63
19	$393.23	$393.23	$173,748.42	$173,748.42
20	-$1,036.80	-$1,036.80	$171,679.97	$171,679.97
21	$70,725.27	$70,725.27	$276,786.46	$276,786.46
22	$69,208.14	$69,208.14	$274,592.04	$274,592.04
23	$67,745.49	$67,745.49	$272,331.78	$272,331.78
24	$66,035.96	$66,035.96	$270,003.71	$270,003.71
25	$64,378.15	$64,378.15	$267,605.80	$267,605.80
	$526,949.69	$526,949.69	$5,106,908.84	$5,106,908.84

Even though this entity does not pay taxes or receive tax benefits, the income before and after were calculated to compare with other models. As a result, the income is the same before and after taxes.

[1] Model 4A – Municipal Utility (MU) based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 4B – MU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

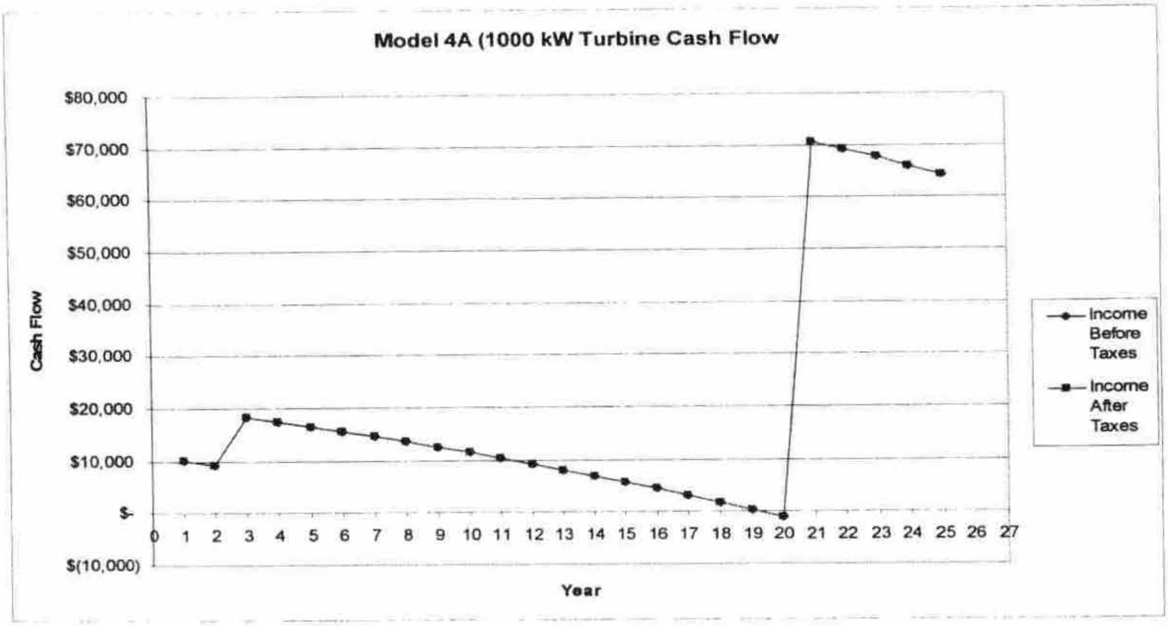

Figure 12. Model 4A (1000 kW turbine)[1] – cash flow

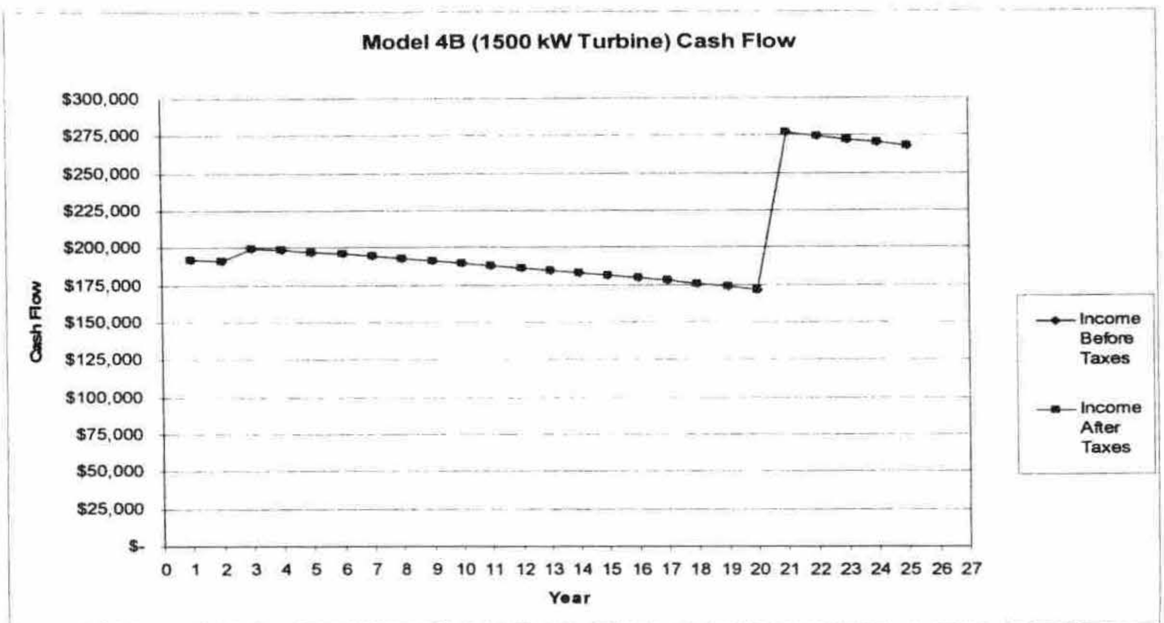

Figure 13. Model 4B (1500 kW Turbine)[2] – cash flow

[1] Model 4A – Municipal Utility (MU) based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 4B – MU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

Table 28. Model 4 - financial costs and returns per kWh

	MODEL 4A[1]			MODEL 4B[2]		
YEAR	Cost[3]	Income Before Taxes	Income After Taxes[4]	Cost[5]	Income Before Taxes	Income After Taxes[6]
1	$0.0504	$0.0046	$0.0046	$0.0247	$0.03021	$0.03021
2	$0.0508	$0.0042	$0.0042	$0.0249	$0.03002	$0.03002
3	$0.0466	$0.0083	$0.0083	$0.0236	$0.03139	$0.03139
4	$0.0470	$0.0079	$0.0079	$0.0238	$0.03119	$0.03119
5	$0.0474	$0.0075	$0.0075	$0.0240	$0.03098	$0.03098
6	$0.0479	$0.0071	$0.0071	$0.0242	$0.03077	$0.03077
7	$0.0483	$0.0066	$0.0066	$0.0244	$0.03054	$0.03054
8	$0.0488	$0.0062	$0.0062	$0.0246	$0.03032	$0.03032
9	$0.0492	$0.0057	$0.0057	$0.0249	$0.03008	$0.03008
10	$0.0497	$0.0052	$0.0052	$0.0251	$0.02984	$0.02984
11	$0.0502	$0.0047	$0.0047	$0.0254	$0.02959	$0.02959
12	$0.0507	$0.0042	$0.0042	$0.0256	$0.02933	$0.02933
13	$0.0513	$0.0037	$0.0037	$0.0259	$0.02905	$0.02905
14	$0.0518	$0.0031	$0.0031	$0.0262	$0.02880	$0.02880
15	$0.0524	$0.0026	$0.0026	$0.0264	$0.02852	$0.02852
16	$0.0529	$0.0020	$0.0020	$0.0267	$0.02823	$0.02823
17	$0.0535	$0.0014	$0.0014	$0.0270	$0.02793	$0.02793
18	$0.0541	$0.0008	$0.0008	$0.0273	$0.02762	$0.02762
19	$0.0548	$0.0002	$0.0002	$0.0276	$0.02731	$0.02731
20	$0.0554	-$0.0005	-$0.0005	$0.0280	$0.02698	$0.02698
21	$0.0229	$0.0321	$0.0321	$0.0114	$0.04350	$0.04350
22	$0.0236	$0.0314	$0.0314	$0.0118	$0.04316	$0.04316
23	$0.0243	$0.0307	$0.0307	$0.0121	$0.04280	$0.04280
24	$0.0250	$0.0299	$0.0299	$0.0125	$0.04244	$0.04244
25	$0.0258	$0.0292	$0.0292	$0.0129	$0.04206	$0.04206

[1] Model 4A – Investor Owned Utility (IOU) based on a 1000 kW turbine, 60 meter rotor diameter, and 60 meter height, and wind speed 7.18 m/s
[2] Model 4B – IOU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s
[3] Total costs for Model 4A– construction, financial, and annual costs
[4] Income after taxes
[5] Total costs for Model 4B– construction, financial, and annual costs
[6] Income after taxes

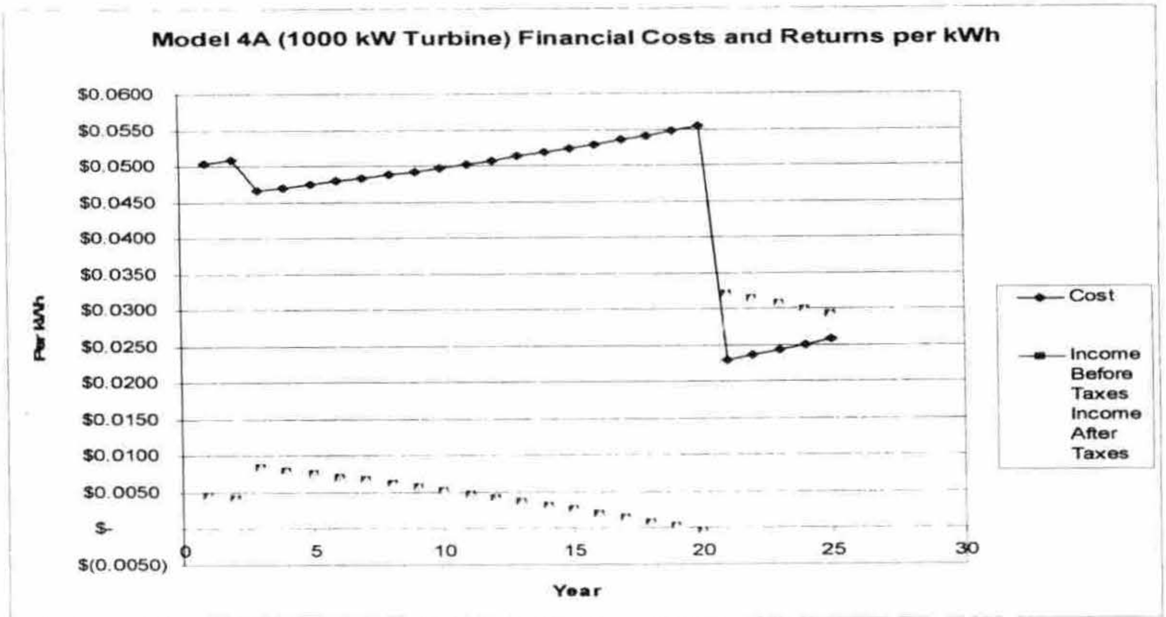

Figure 14. Model 4A (1000 kWh turbine)[1] – financial costs and returns per kWh

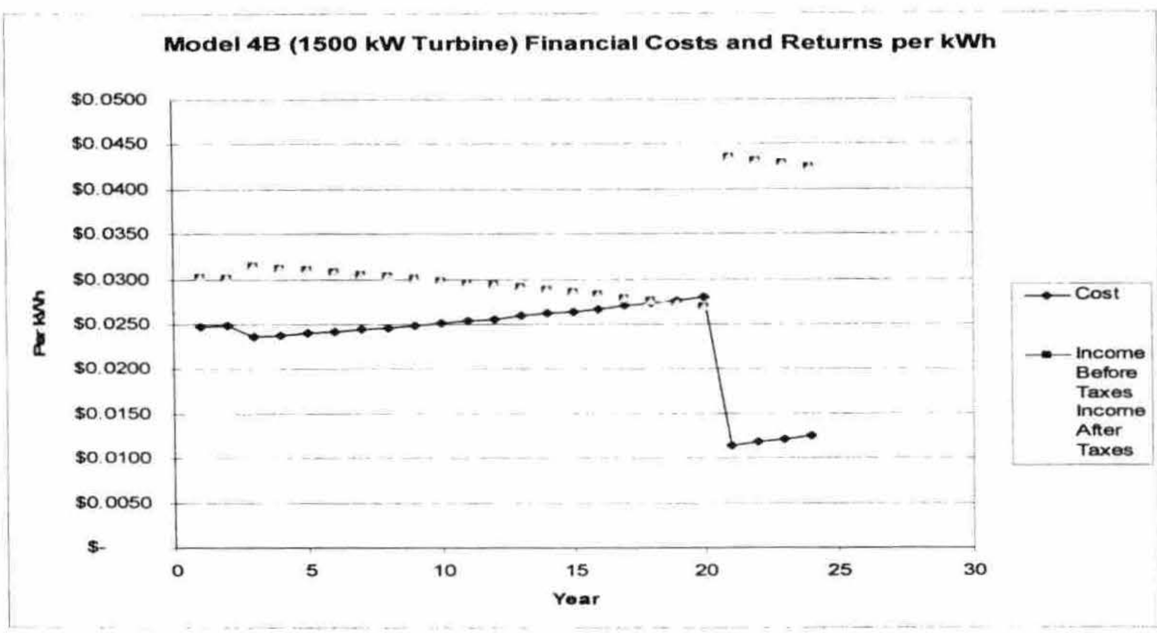

Figure 15. Model 4B (1500 kWh turbine)[2] – financial costs and returns per kWh

[1] Model 4A – Investor Owned Utility (IOU) based on a 1000 kW turbine, 60 metes rotor diameter, and 60 meter height, and wind speed 7.18 m/s

[2] Model 4B – IOU based on a 1500 kW turbine, 80 meter rotor diameter, and 80 meter height, and wind speed 8.02 m/s

Model 4 is an example of an entity that is does not pay federal or state taxes and is not eligible to receive either a PTC or REPI. An example of this model would be a municipal government or some other type of public entity that is not taxable and yet is not eligible for tax credits. As a result, in this model the entity does not pay federal, state, or property taxes. Even though the entity may be listed as a non-profit entity, financially, the entity may not be able to accommodate the tax incentives due to regulations.

The differences in 4A and 4B are in the assumptions of the wind turbine. Model 4A uses a wind turbine with a 60-meter rotor diameter, placed at a height of 60 meters, rated at 1,000 kW, and with an initial Wind Class of 3. Model 4B uses a wind turbine with an 80-meter rotor diameter, placed at a height of 80 meters, rated at 1,500 kW, and placed at a site with an initial Wind Class of 4. All other financial variables remained the same. Even though Model 4 is not directly affected by federal and state tax rates, Model 4A has negative federal taxable income, and 4B was created for comparison purposes with other tax structures as with the other models.

Model 4 is a base model when no taxes are paid and tax benefits received. As a result, in year two, the warranty no longer is in effect, which results in an increase in the net cash flow from year 2 to year 3. From year 11 to year 20, the entity is still servicing debt. After year 20, the debt-financing period has been completed. Since R remains constant, due to both p_i and W remaining the same, the cash flows before and after taxes are downward sloping, as shown in Figures 12 and 13. Due to the positive inflation, $r > 0$, cost is an upward sloping function, shown in Figures 14 and 15.

In addition, in Model 4A the initial debt payment is never fully recovered with $t_B > 25$, which is longer than the assumed lifespan of the turbine. However, the payback period for the larger wind turbine at a site with a higher average wind speed, the payback period is when $t_B = 6$.

Comparison

Table 29. 'A' Scenarios – cash flow

Year	Income Before Taxes	Model 1A - Income After Taxes and PTC[1]	Model 2A - Income After Incentives[2]	Model 3A - Income After Taxes[3]	Model 4A - Income[4]
1	$10,061.36	$17,558.36	$49,758.36	-$22,138.63	$10,061.36
2	$9,221.36	$17,909.27	$50,109.27	-$22,978.63	$9,221.36
3	$8,356.16	$27,270.71	$60,470.71	-$13,843.83	$18,356.16
4	$17,465.00	$28,642.99	$60,842.99	-$14,734.99	$17,465.00
5	$16,547.11	$29,026.43	$61,226.43	-$15,652.88	$16,547.11
6	$15,601.68	$29,421.39	$61,621.39	-$16,498.31	$15,601.68
7	$14,627.89	$29,828.19	$62,028.19	-$17,572.10	$14,627.89
8	$13,624.89	$30,247.19	$62,447.19	-$18,575.10	$13,624.89
9	$12,591.80	$30,678.77	$62,878.77	-$19,608.19	$12,591.80
10	$11,527.71	$31,123.29	$63,323.29	-$20,672.28	$11,527.71
11	$10,431.70	-$23,489.53	$10,431.70	-$23,489.53	$10,431.70
12	$9,302.81	-$24,432.15	$9,302.81	-$24,432.15	$9,302.81
13	$8,140.05	-$25,403.05	$8,140.05	-$25,403.05	$8,140.05
14	$6,942.41	-$26,403.08	$6,942.41	-$26,403.08	$6,942.41
15	$5,708.85	-$27,433.11	$5,708.85	-$27,433.11	$5,708.85
16	$4,438.27	-$28,484.04	$4,438.27	-$28,484.04	$4,438.27
17	$3,129.58	-$29,586.79	$3,129.58	-$29,586.79	$3,129.58
18	$1,781.62	-$30,712.34	$1,781.62	-$30,712.34	$1,781.62
19	$393.23	-$31,871.64	$393.23	-$31,871.64	$393.23
20	-$1,036.80	-$33,301.69	-$1,036.80	-$33,301.69	-$1,036.80
21	$70,725.27	$24,575.82	$70,725.27	$24,575.82	$70,725.27
22	$69,208.14	$23,475.90	$69,208.14	$23,475.90	$69,208.14
23	$67,645.49	$22,342.98	$67,645.49	$22,342.98	$67,645.49
24	$66,035.96	$21,176.07	$66,035.96	$21,176.07	$66,035.96
25	$64,378.15	$19,974.16	$64,378.15	$19,974.16	$64,378.15
	$526,849.69	$102,124.11	$981,931.32	$351,847.43	$526,849.69

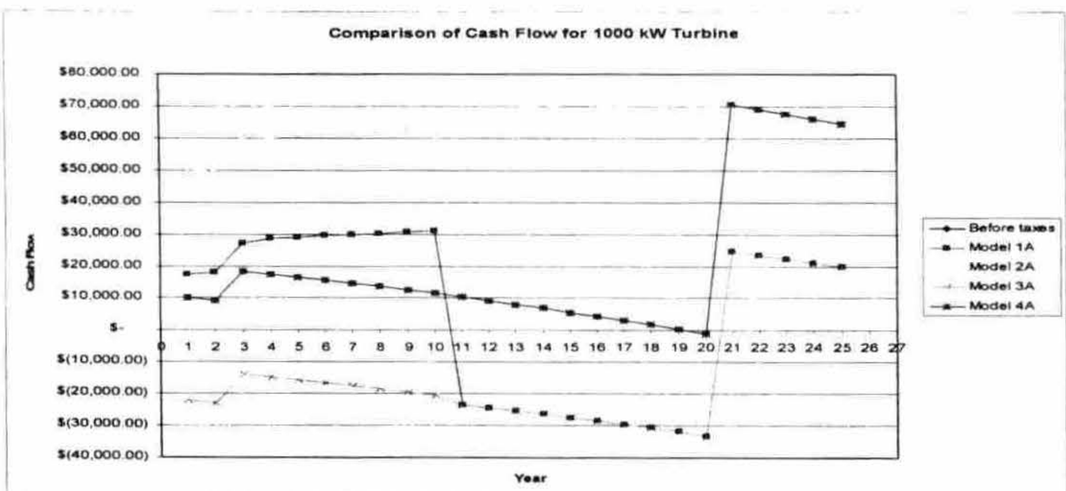

Figure 20. Comparison of cash flow for 1000 kW turbine

[1] Investor Owned Utility (IOU) with PTC, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s

[2] Municipal Utility (MU) with REPI, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s

[3] IOU without PTC, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s

[4] MU without REPI, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s

Table 30. 'B' Scenarios – cash flow

Year	Income Before Taxes	Model 1B - Income After Taxes and PTC[1]	Model 2B - Income After Incentives[2]	Model 3B - Income After Taxes[3]	Model 4B - Income[4]
1	$192,196.96	$259,570.81	$306,720.81	$145,046.96	$192,196.96
2	$190,981.96	$261,791.52	$308,941.52	$43,831.96	$190,981.96
3	$199,730.51	$273,298.32	$321,228.86	$151,799.98	$199,730.51
4	$198,441.52	$275,866.96	$323,584.81	$150,723.67	$198,441.52
5	$197,113.85	$278,512.66	$326,011.45	$149,615.07	$197,113.85
6	$195,746.36	$281,237.73	$328,510.88	$148,473.21	$195,746.36
7	$194,337.84	$283,812.15	$331,085.30	$147,064.69	$194,337.84
8	$192,887.07	$286,463.80	$333,736.95	$145,613.92	$192,887.07
9	$191,392.77	$289,195.00	$336,468.15	$144,119.62	$191,392.77
10	$189,853.65	$292,008.14	$339,281.29	$142,580.50	$189,853.65
11	$188,268.35	$78,776.22	$188,268.35	$78,776.22	$188,268.35
12	$186,635.49	$77,843.86	$186,635.49	$77,843.86	$186,635.49
13	$184,953.64	$76,883.53	$184,953.64	$76,883.53	$184,953.64
14	$183,221.35	$75,894.39	$183,221.35	$75,894.39	$183,221.35
15	$181,437.08	$74,875.57	$181,437.08	$74,875.57	$181,437.08
16	$179,599.28	$73,826.19	$179,599.28	$73,826.19	$179,599.28
17	$177,706.35	$72,745.32	$177,706.35	$72,745.32	$177,706.35
18	$175,756.63	$71,632.03	$175,756.63	$71,632.03	$175,756.63
19	$173,748.42	$70,485.35	$173,748.42	$70,485.35	$173,748.42
20	$171,679.97	$69,304.26	$171,679.97	$69,304.26	$171,679.97
21	$276,786.46	$129,320.07	$276,786.46	$129,320.07	$276,786.46
22	$274,592.04	$128,067.05	$274,592.04	$128,067.05	$274,592.04
23	$272,331.78	$126,776.44	$272,331.78	$126,776.44	$272,331.78
24	$270,003.71	$125,447.12	$270,003.71	$125,447.12	$270,003.71
25	$267,605.80	$124,077.91	$267,605.80	$124,077.91	$267,605.80
	$5,107,008.84	$4,157,712.40	$6,419,896.37	$2,844,824.89	$5,107,008.84

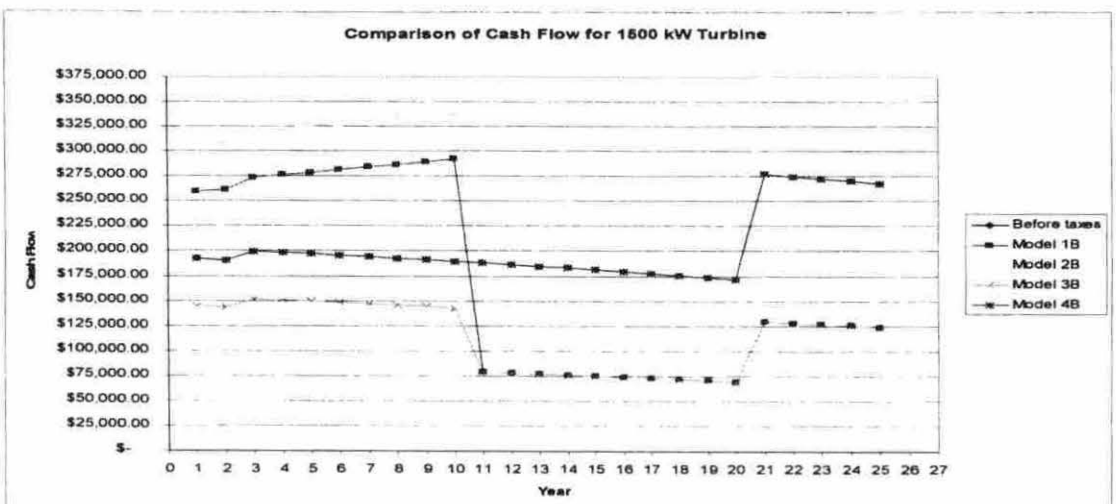

Figure 21. Comparison of cash flow for 1500 kW turbine

[1] Investor Owned Utility (IOU) with PTC, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[2] Municipal Utility (MU) with REPI, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[3] IOU without PTC, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[4] MU without REPI, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s

Table 31. 'A' Scenarios – financial costs and returns per kWh

Year	Cost[1]	Income Before Taxes	Model 1A[2]	Model 2A[3]	Model 3A[4]	Model 4A[5]
1	$0.0504	$0.0046	$0.0079	$0.0225	-$0.0100	$0.0046
2	$0.0508	$0.0042	$0.0081	$0.0227	-$0.0104	$0.0042
3	$0.0466	$0.0083	$0.0128	$0.0274	-$0.0062	$0.0083
4	$0.0470	$0.0079	$0.0129	$0.0275	-$0.0066	$0.0079
5	$0.0474	$0.0075	$0.0131	$0.0277	-$0.0070	$0.0075
6	$0.0479	$0.0071	$0.0133	$0.0279	-$0.0075	$0.0071
7	$0.0483	$0.0066	$0.0135	$0.0281	-$0.0079	$0.0066
8	$0.0488	$0.0062	$0.0137	$0.0283	-$0.0084	$0.0062
9	$0.0492	$0.0057	$0.0139	$0.0285	-$0.0088	$0.0057
10	$0.0497	$0.0052	$0.0141	$0.0287	-$0.0093	$0.0052
11	$0.0502	$0.0047	-$0.0106	$0.0047	-$0.0106	$0.0047
12	$0.0507	$0.0042	-$0.0110	$0.0042	-$0.0110	$0.0042
13	$0.0513	$0.0037	-$0.0115	$0.0037	-$0.0115	$0.0037
14	$0.0518	$0.0031	-$0.0119	$0.0031	-$0.0119	$0.0031
15	$0.0524	$0.0026	-$0.0124	$0.0026	-$0.0124	$0.0026
16	$0.0529	$0.0020	-$0.0129	$0.0020	-$0.0129	$0.0020
17	$0.0535	$0.0014	-$0.0134	$0.0014	-$0.0134	$0.0014
18	$0.0541	$0.0008	-$0.0139	$0.0008	-$0.0139	$0.0008
19	$0.0548	$0.0002	-$0.0144	$0.0002	-$0.0144	$0.0002
20	$0.0554	-$0.0005	-$0.0151	-$0.0005	-$0.0151	-$0.0005
21	$0.0229	$0.0321	$0.0111	$0.0321	$0.0111	$0.0321
22	$0.0236	$0.0314	$0.0106	$0.0314	$0.0106	$0.0314
23	$0.0243	$0.0307	$0.0101	$0.0307	$0.0101	$0.0307
24	$0.0250	$0.0299	$0.0096	$0.0299	$0.0096	$0.0299
25	$0.0258	$0.0292	$0.0090	$0.0292	$0.0090	$0.0292

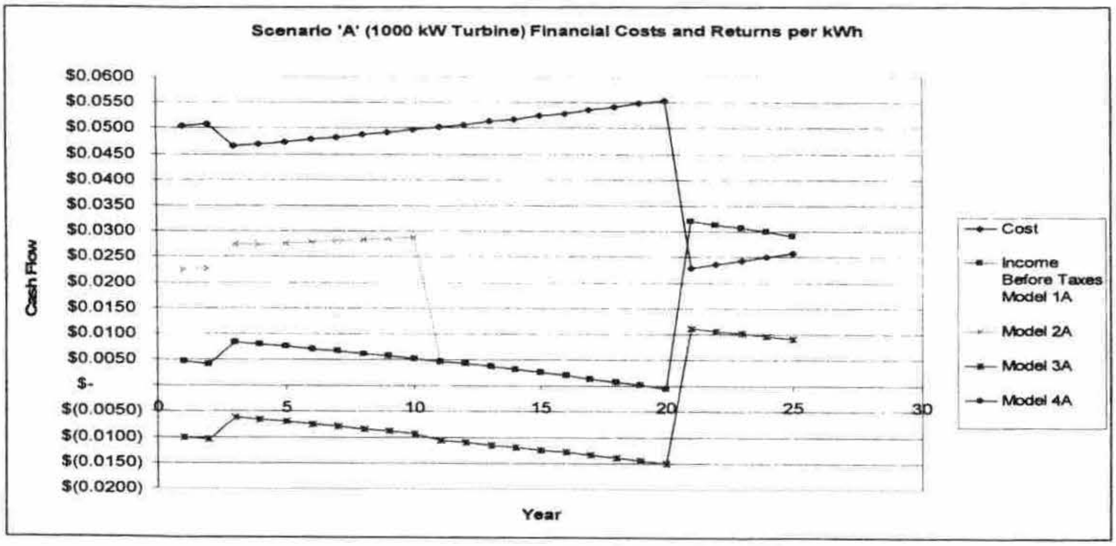

Figure 22. 'A' Scenario (1000 kW turbine) financial costs and returns per kWh

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[1] Total costs – construction, financial, and annual costs
[2] Investor Owned Utility (IOU) with PTC, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s
[3] Municipal Utility (MU) with REPI, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s
[4] IOU without PTC, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s
[5] MU without REPI, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s

Table 32. 'B' Scenarios – financial costs and returns per kWh

Year	Cost[1]	Income Before Taxes	Model 1B[2]	Model 2B[3]	Model 3B[4]	Model 4B[5]
1	$0.0247	$0.03021	$0.04080	$0.04820	$0.02280	$0.03021
2	$0.0249	$0.03002	$0.04115	$0.04850	$0.02261	$0.03002
3	$0.0236	$0.03139	$0.04295	$0.05040	$0.02386	$0.03139
4	$0.0238	$0.03119	$0.04336	$0.05080	$0.02369	$0.03119
5	$0.0240	$0.03098	$0.04377	$0.05120	$0.02352	$0.03098
6	$0.0242	$0.03077	$0.04420	$0.05160	$0.02334	$0.03077
7	$0.0244	$0.03054	$0.04461	$0.05200	$0.02311	$0.03054
8	$0.0246	$0.03032	$0.04502	$0.05240	$0.02289	$0.03032
9	$0.0249	$0.03008	$0.04545	$0.05280	$0.02265	$0.03008
10	$0.0251	$0.02984	$0.04590	$0.05330	$0.02241	$0.02984
11	$0.0254	$0.02959	$0.01238	$0.02959	$0.01238	$0.02959
12	$0.0256	$0.02933	$0.01223	$0.02933	$0.01223	$0.02933
13	$0.0259	$0.02905	$0.01208	$0.02905	$0.01208	$0.02905
14	$0.0262	$0.02880	$0.01193	$0.02880	$0.01193	$0.02880
15	$0.0264	$0.02852	$0.01177	$0.02852	$0.01177	$0.02852
16	$0.0267	$0.02823	$0.01160	$0.02823	$0.01160	$0.02823
17	$0.0270	$0.02793	$0.01143	$0.02793	$0.01143	$0.02793
18	$0.0273	$0.02762	$0.01126	$0.02762	$0.01126	$0.02762
19	$0.0276	$0.02731	$0.01108	$0.02731	$0.01108	$0.02731
20	$0.0280	$0.02698	$0.01089	$0.02698	$0.01089	$0.02698
21	$0.0114	$0.04350	$0.02033	$0.04350	$0.02033	$0.04350
22	$0.0118	$0.04316	$0.02013	$0.04316	$0.02013	$0.04316
23	$0.0121	$0.04280	$0.01993	$0.04280	$0.01993	$0.04280
24	$0.0125	$0.04244	$0.01972	$0.04244	$0.01972	$0.04244
25	$0.0129	$0.04206	$0.01950	$0.04206	$0.01950	$0.04206

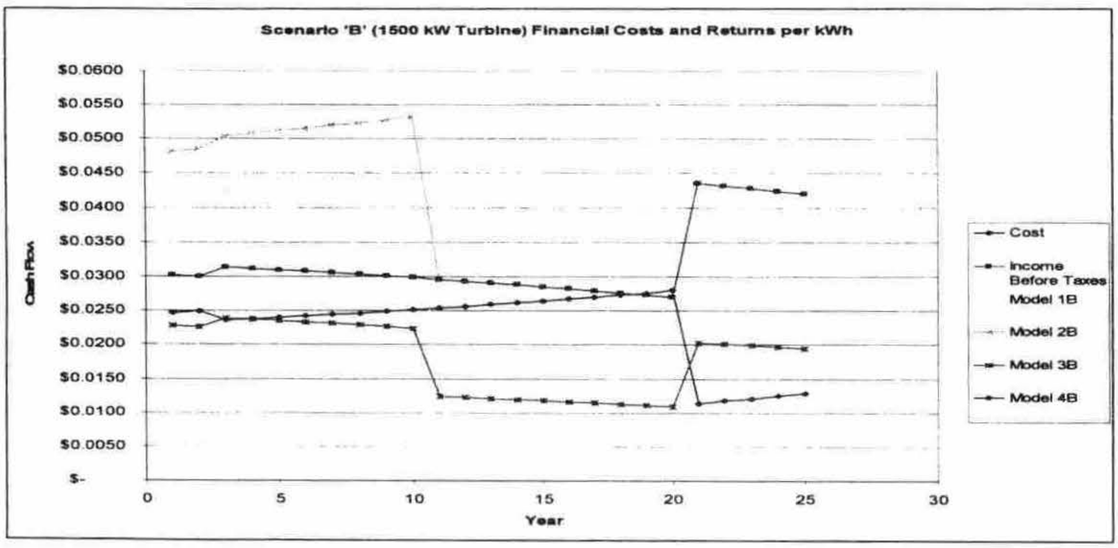


Figure 23. 'B' Scenario (1500 kW turbine) financial costs and returns per kWh

[1] Total costs – construction, financial, and annual costs
[2] Investor Owned Utility (IOU) with PTC, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[3] Municipal Utility (MU)with REPI, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[4] IOU without PTC, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[5] MU without REPI, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s

Table 33. 'A' Scenarios – cumulative tax totals by model type

	MODEL 1A[1]	MODEL 2A[2]	MODEL 3A[3]	MODEL 4A[4]
Cumulative Federal Taxes	$67,097.52	$0	$67,097.52	$0
Cumulative Federal Tax Credit/Incentives	$455,081.62	$455,081.62	$0	$0
Cumulative State Taxes	$6,709.75	$0	$6,709.75	$0
Cumulative Property Taxes	$805,000.00	$0	$805,000.00	$0
Cumulative Taxes Paid	$872,097.52	$0	$872,097.52	$0
Net Tax Difference	$417,015.90	-$455,081.62	$872,097.92	$0
Cumulative Cash Flow	$103,124.13	$981,931.42	-$393,107.72	$526,849.79

Table 34. 'B' Scenarios – cumulative cash flow by model type

	MODEL 1B[5]	MODEL 2B[6]	MODEL 3B[7]	MODEL 4B[8]
Cumulative Federal Taxes	$984,939.95	$0	$984,939.95	$0
Cumulative Federal Tax Credit/Incentives	$1,312,887.53	$1,312,887.53	$0	$0
Cumulative State Taxes	$98,493.99	$0	$98,493.99	$0
Cumulative Property Taxes	$1,178,750.00	$0	$1,178,750.00	$0
Cumulative Taxes Paid	$2,163,689.95	$0	$2,163,689.95	$0
Net Tax Difference	$850,802.42	-$1,312,887.53	$2,163,689.95	$0
Cumulative Cash Flow	$4,157,712.67	$6,419,896.49	$2,844,825.00	$5,107,008.95

[1] Investor Owned Utility (IOU) with PTC, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s
[2] Municipal Utility (MU) with REPI, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s
[3] IOU without PTC, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s
[4] MU without REPI, based on a 1000 kW turbine, 60 meter rotor diameter, 60 meter height, and wind speed of 7.18 m/s
[5] IOU with PTC, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[6] MU with REPI, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[7] IOU without PTC, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s
[8] MU without REPI, based on a 1500 kW turbine, 80 meter rotor diameter, 80 meter height, and wind speed of 8.02 m/s

Economic benefits

It is clear that a tax-exempt entity receiving tax credits/incentives has the highest cumulative cash flow, regardless of wind speed and turbine. Model 1 has a lower cumulative cash flow than Model 2 due to Model 1 paying federal, state, and property taxes. Scenarios A and B demonstrate economies of scale. As the rating of the turbine increases, the cost per kWh decreases. For Model 1 and Model 3, which are taxed, there would also be a difference in revenue per turbine as the number of turbines changed. However, for Model 2 and Model 4, which are not taxed, the economies of scale would remain the same. In addition to the economic impact of tax credits/incentives, the benefits of a larger wind turbine at a site with a higher mean wind speed should be noted. This is shown in Tables 31 and 32 and Figures 22 and 23. As the rating of the wind turbine increased, the income per kWh also increased.

These models did not evaluate the effect of the state tax credit. However, from analyzing the benefits from the federal tax credit/incentive, similar benefits could be applied. This would be a decision made by each state, and could make each state a competitor in the energy market, and economically force other states to follow suit or be left out of the pursuit for the employment and other benefits that would be associated with a wind turbine(s) or facility.

When comparing the 'A' scenarios, there are similarities in the cash flows. After year 10, when the federal tax credits/incentives expired, Model 2A and Model 4A followed the same cash flow, while Model 1 and Model 3 followed the same cash flow. This is because Model 2A and Model 4A are tax-exempt entities, while Models 1A and 3A are not tax-exempt.

Being eligible and collecting the tax credits/incentives can make a difference in an economic profit of a wind turbine. Model 4A, which did not receive any tax benefits and was paying taxes, had a negative cumulative cash flow after 25 years. As a result, the model never reached the point of exceeding the initial equity investment. However, in both Model 1A and Model 2A the cumulative cash flow did not exceed the initial equity. Model 2A had the highest cumulative cash flow, signaling that both tax exemption and tax credits/incentives provide the best scenario for wind energy economic viability.

Due to the lack of taxes being paid in the 'A' scenarios, the turbine values were changed to increase the overall revenue. During the first 10 years, Model 2B produced the highest net cash flow. After year 10 and the expiration of the tax credits/incentives, Model 2B and Model 4B, both tax-exempt entities, have identical cash flows, while the two taxable entities, Model 1B and Model 3B, have identical cash flows. Once again, Model 2 had the highest cumulative cash flow, indicating that both tax exemption and tax credits/incentives could promote growth in the wind energy sector.

From Table 35, the models that receive tax credits/incentives, have two periods of payback. The first period is when the initial $I_C > E_I$. However, after the tax credit/incentive period has expired, there are negative cash flows, resulting in a decreasing I_C. The net cash flows start to increase after the turbine debt service period has been completed. For Model 1, the payback period is when $t_B > 25$, after the life expectancy of the turbine. However, for Model 2, the second payback period is when $t_B = 3$. The difference from Model 1 and Model 2 is that Model 1 is paying taxes while Model 2 is a tax-exempt entity. Economies of scale also exist in the size of the turbine, as demonstrated from the difference in cost of

Scenarios A and Scenarios B. As the rating of turbine increases, the cost per kWh decreases. From Table 33 and 34, Model 2B, a tax-exempt entity, exhibits a negative tax difference because the cumulative credits/incentives are greater than the taxes paid. Model 4, which pays taxes and does not receive or is eligible for tax benefits exhibits the largest net tax differences. This would be the greatest benefit to society in terms of increasing government revenue on a state and federal government level.

CHAPTER 5. CONCLUSION AND FURTHER RESEARCH

Based on the analyses conducted, three major findings emerge from this thesis research.

1. The lifetime cash flow analyses for each wind generation project shows four distinct phases. The initial period ends in year two when the warranty period for the turbines end. The second period ends in year ten when the tax deductions for the turbine depreciation, PTC, and REPI incentives end. The third period ends in 20 years when the bond repayment period ends. The final period represents the remaining life of the turbines when the there is no warranty, depreciation, or debt.
2. The Municipal and REC Nonprofit Utilities generate a shorter payback period and greater cumulative cash flows than IOU or REC For Profit Utilities. This finding is consistent across comparisons where PTC and REPI are removed and across comparisons involving sensitivity analyses to two different turbine size and energy production systems.
3. The analysis shows that the larger turbine scenarios (1500 kW) generated more cash flow across all four-model assumptions, than did the smaller turbine scenarios (1000 kW). This finding provides evidence that that supports the industry trend toward larger utility scale turbines.

Suggestions for further research includes more detailed analysis of rent seeking behavior and organization of business entities that can accommodate use of higher levels of depreciation and energy incentives. A preliminary analysis of 3rd party investment suggests that private sector firms and possibly public sector non-profits may reduce the period of years required for payback on the initial investments by adding partners that can fully utilize depreciation and renewable energy credits and incentives.

APPENDIX A. MODEL VARIABLES

Term	Variable	Equation	Default Value
Rotor Diameter	Z_{Di}		60 meters
Turbine Height	Z_H		60 meters
Turbine Rating	Z_R		1000 kW
Number of Turbines	n		1
Price	p_i		
Annual Price	p_A	$p_i = p_A \times 0.01$	5.5 cents/kW
Seasonal Price	p_S	$p_i = S_r \times p_{S_P} + (1 - S_r) \times p_{S_{NP}}$	8 cents/kW for peak 4 cents/kW for non-peak
Daily Price	p_D	$p_i = D_r \times p_{D_P} + (1 - D_r) \times p_{D_{NP}}$	8 cents/kW for peak 4 cents/kW for non-peak
Wind Speed	V_i	$V_i = V_{50} \times \left(\frac{h_i}{50}\right)^{1/7}$	7.18 m/s
Medium Speed	V_m	$V_m = V_i$	7/18 m/s
Low Speed	V_l	$V_l = V_m - 0.5$	6.88 m/s
High Speed	V_h	$V_h = V_m + 0.5$	7.48 m/s
Energy Constant	λ		
Energy production	W	W	
Annual Revenue	R	$R = W \times p_i$	
Interconnection Costs	C_I		$50000
Planning, Legal, Engineering, and Admin Mgt. Costs	C_A		$50000
Construction Grants	C_G		$0
Total Construction Costs	C_{TCC}	$C_{TCC} = Z_R \times 1300 + C_A + C_I - C_G$	
Equity percent	E_p		40% of TCC
3rd Part Initial Investment	E_3		
Equity Investment	E_I	$E_I = C_{TCC} \times E_p$	
Debt Financing percent	C_{D_p}	$C_{D_p} = 1 - E_p$	60% of TCC
Debt Financing Period	C_{D_T}		20 Years
Debt Financing interest rate	i_D		6%
Debt Financing	C_D	$C_D = C_{TCC} - E_I$	

Annual Debt Service	C_{D_A}	$C_{D_A} = \left(\frac{C_D \times i_D}{1-(1+i_D)^{-C_{D_T}}} \right)$	
Inflation rate	r		3%
Warranty	C_W		$20000
Warranty Period	C_{W_T}		2 Years
Annual Warranty	C_{W_A}	$C_{W_A} = \frac{C_W}{C_{W_T}}$	$10,000
O&M percent	C_{O_P}		2.5 %
O&M constant	C_{O_F}		
O&M	C_O	$C_O = C_{O_P} \times Z_R$	
Annual O&M	C_{O_A}	$C_{O_A} = C_O \times (1-r_i)^{t_i}$	$25,000
Land Payment per year	C_L		$3,000 per turbine
Annual Land Payment	C_{L_A}	$C_{L_A} = C_L \times (1-r_i)^{t_i}$	$3,000
Total Costs	C_T	$C_{TC} = C_{O_A} + C_{W_A} + C_{L_A} + C_{D_A}$	
Net Cash Flow Before Taxes	I_B	$I_B = R - C_{TCC}$	
Cost per kWh before taxes	C_k	$C_k = \frac{C_T}{W}$	
Useful life	t_i		
Turbine Depreciation Period	t_Z		10 Years
Turbine Depreciation	Z_T	$Z_T = \left(\frac{Z_R \times 1300}{t_Z} \right)$	$130,000
Excess Depreciation	T_E		
Net Unused Depreciation	T_U		
Passive Income	I_P		
Taxable Federal Income Tax	T_{F_T}	$T_{F_T} = I_B - Z_T$	
Federal income Tax	T_F	$T_F = (T_{F_T} - \alpha_i) \times \beta_i + \delta_i$	
State income tax percent	T_{S_p}		
State income tax as Federal Tax	T_S	$T_S = T_{S_p} \times T_F$	
State income tax as Cash flow before taxes	T_S	$T_S = T_{s_p} \times I_B$	
Property Tax levy rate	T_{P_r}		$23 per $1,000 valuation
Property Tax percent Abated	T_{P_p}		70%

Property Tax energy rate	T_W		
Property Tax with levy rate	T_P	$T_P = \left(\dfrac{C_{TCC} \times T_{P_r}}{1000} \right)$	
Property Tax with abatement rate	T_P	$T_P = \left(\dfrac{C_{TCC} \times T_{P_r}}{1000} \right) \left(1 - T_{P_p}\right)$	
Property Tax based on energy generation	T_P	$T_P = W \times T_W$	
Tax credit per kW	T_C		1.8 cents/kWh
Total Tax credit/incentives	T_T	$T_T = T_C \times W$	
Unused Federal PTC/REPI	I_U	$I_U = T_T - I_P$	
Cash flow	I_A	$I_A = I_B + T_T - T_F - T_S - T_P$	
Income per kW produced	I_k	$I_k = \dfrac{I_A}{W}$	
Cumulative cash flow	I_C	$I_C = \sum_{i=1}^{t_i} I_A$	
Break Even point for equity	t_B	$t_B = I_C > E_I$	

APPENDIX B. PROOF OF BETZ's LIMIT

This proof shows that a wind turbine can only be 16/27 percent efficient. It is assumed that the average wind speed through the rotor area is the average of the initial wind speed before the wind turbine, v_1, and the wind speed after the passage through the rotor plane, v_2.The mass of the air streaming through the rotor during one second is:

$$m = \rho \times F\left(\frac{v_1 + v_2}{2}\right)$$

where m is the mass per second, ρ is the density of air, F is the swept rotor area, and

$\frac{v_1 + v_2}{2}$ is the average wind speed through the rotor area. According to Newton's Second Law, the power extracted from the wind by the rotor is equal to the m times the decrease in the wind speed squared:

$$P = \frac{1}{2}\left(m\left(v_1^{\,2} - v_2^{\,2}\right)\right)$$

Substituting m from equation 1 into equation 2, the expanded power equation:

$$P = \left(\frac{\rho}{4}\right)\left(v_1^{\,2} - v_2^{\,2}\right)\left(v_1 + v_2\right)F$$

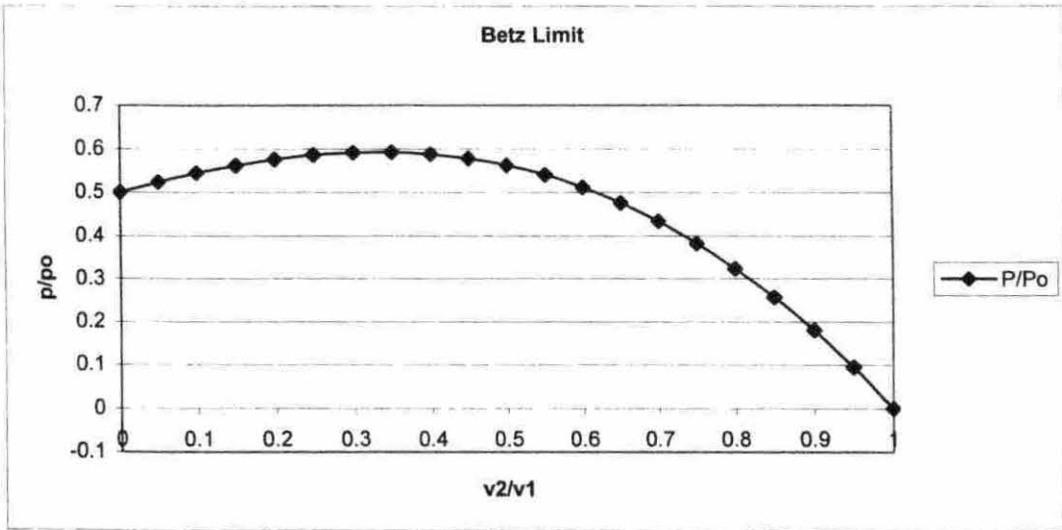
For an undisturbed wind stream, the power generated without a rotor blocking, with rotor area F is:

$$P_O = \left(\frac{\rho}{2}\right)v_1^{\,3}F$$

The ratio between the power we extract from the wind and the power in the undisturbed wind is then solved for $\frac{P}{P_o}$:

$$\frac{P}{P_o}=\frac{1}{2}\left(1-\left(\frac{v_2}{v_1}\right)^2\right)\left(1+\left(\frac{v_2}{v_1}\right)\right)$$

From the plot of $\frac{P}{P_o}$ as a function of $\frac{v_1}{v_2}$, the maximum is when $\frac{v_1}{v_2}$ is 1/3; as a result, the most power that can be extracted is 16/27 of the total wind power.



APPENDIX C. STATE FINANCIAL INCENTIVES

State	Personal Tax	Corporate Tax	Sales Tax	Property Tax	Rebates	Grants	Loans	Production Incentive
Alabama	X					X	X	
Alaska			X				X	
Arizona	X		X		X			
Arkansas		X						
California	X	X		X	X	X	X	
Colorado	X	X			X			X
Connecticut		X	X	X			X	
Delaware					X			
Florida			X		X	X		
Georgia	X	X					X	
Hawaii	X	X	X		X		X	
Idaho	X							
Illinois				X	X	X		
Indiana				X		X		
Iowa		X	X	X		X	X	
Kansas	X	X		X		X		
Kentucky								
Louisiana								
Maine								
Maryland	X	X	X	X	X		X	
Massachusetts	X	X	X	X	X	X		
Michigan						X		
Minnesota			X	X	X	X	X	X
Mississippi							X	
Missouri		X					X	
Montana	X	X		X		X	X	
Nebraska							X	
Nevada			X	X	X			
New Hampshire				X			X	
New Jersey			X		X			
New Mexico		X						
New York	X	X		X	X	X	X	
North Carolina	X	X		X			X	
North Dakota	X	X	X	X				
Ohio	X	X	X	X			X	
Oklahoma		X						
Oregon	X	X		X	X		X	X
Pennsylvania					X	X	X	X
Rhode Island	X		X	X	X	X		
South Carolina					X			
South Dakota				X				
Tennessee							X	
Texas		X		X	X		X	
Utah	X	X						
Vermont			X	X				
Virginia				X			X	
Washington			X		X		X	X
West Virginia		X		X				
Wisconsin				X	X	X	X	
Wyoming								

APPENDIX D. TURBINES USED FOR REGRESSIONS

Turbine	Rated (kW)	Rotor Diameter (m)
Whisper H-80	1	2
Whisper 175	3.2	4.26
Jacobs 29-20	20	8.8
Enertech 40	40	13.4
Windmatic 15s	65	10.4
Nordtank 65	65	16.5
Fuhrlaender FL100	100	21
Vetas 225-29	225	29
Fuhrlaender FL250	250	31
Nordtank 300-31	300	31
Nordtank 500-41	500	41
Vestas 600-44	600	44
NEG Micon 750/44	750	44
NEG Micon 750/48	750	48
NEG Micon NM52/900	900	52.2
NEG 54-950	950	54.2
GE 1.5 s	1500	70.5
GE 1.5 sl	1500	77
NEG 72-1500	1500	72
Nordex N90-2300	2300	90
Nordex N80-2500	2500	80

APPENDIX E. SAS OUTPUT

All Turbines – Correlations

All Turbines

The CORR Procedure

5 Variables: k D V rated h

Simple Statistics

Variable	N	Mean	Std Dev	Sum
k	250	0.0000602	0.0000258	0.01506
D	250	45.44672	24.96328	11362
V	250	7.30387	0.71158	1826
rated	250	834.61440	739.47336	208654
h	250	55.46000	30.04495	13865

Simple Statistics

Variable	Minimum	Maximum	Label
k	4.5732E-7	0.0000895	Constant
D	3.00000	90.00000	Diameter
V	5.78000	8.34000	Velocity
rated	1.00000	2500	Rated turbine
h	10.00000	115.00000	Height

Pearson Correlation Coefficients, N = 250
Prob > |r| under H0: Rho=0

	k	D	V	rated	h
k Constant	1.00000	0.43038 <.0001	0.29137 <.0001	0.40576 <.0001	0.29695 <.0001
D Diameter	0.43038 <.0001	1.00000	0.67666 <.0001	0.94822 <.0001	0.70125 <.0001
V Velocity	0.29137 <.0001	0.67666 <.0001	1.00000	0.63603 <.0001	0.96432 <.0001
rated Rated turbine	0.40576 <.0001	0.94822 <.0001	0.63603 <.0001	1.00000	0.66512 <.0001
h Height	0.29695 <.0001	0.70125 <.0001	0.96432 <.0001	0.66512 <.0001	1.00000

All Turbines

The GLM Procedure

Dependent Variable: k Constant

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	6.2364895E-8	1.0394149E-8	24.41	<.0001
Error	243	1.0347245E-7	4.258126E-10		
Corrected Total	249	1.6583735E-7			

R-Square	Coeff Var	Root MSE	k Mean
0.376061	34.25616	0.000021	0.000060

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	0.0000952409	0.00001836	5.19	<.0001
D	-.0000027381	0.00000079	-3.47	0.0006
V	-.0000051775	0.00000257	-2.01	0.0453
rated	0.0000002013	0.00000003	7.15	<.0001
rd	-.0000000021	0.00000000	-1.30	0.1956
d2	0.0000000310	0.00000003	1.20	0.2317
r2	-.0000000000	0.00000000	-0.21	0.8313

The REG Procedure
Model: MODEL1
Dependent Variable: k Constant

Root MSE	0.00002064	R-Square	0.3761
Dependent Mean	0.00006024	Adj R-Sq	0.3607
Coeff Var	34.25616		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	0.00009524	0.00001836	5.19	<.0001
D	Diameter	1	-0.00000274	7.898227E-7	-3.47	0.0006
V	Velocity	1	-0.00000518	0.00000257	-2.01	0.0453
rated	Rated turbine	1	2.013396E-7	2.816706E-8	7.15	<.0001
rd	rated*diam	1	-2.10949E-9	1.625337E-9	-1.30	0.1956
d2	diam sq	1	3.101291E-8	2.586526E-8	1.20	0.2317
r2	Rated sq	1	-5.8835E-12	2.75862E-11	-0.21	0.8313

Small Turbines Rated less than 50 kW

Small Turbines Rated less than 50 kW

The CORR Procedure

5 Variables: k D V rated h

Simple Statistics

Variable	N	Mean	Std Dev	Sum
k	32	0.0000645	0.0000126	0.00207
D	32	7.36500	4.16358	235.68000
V	32	6.64000	0.47938	212.48000
rated	32	16.05000	15.90966	513.60000
h	32	27.50000	11.63975	880.00000

Simple Statistics

Variable	Minimum	Maximum	Label
k	0.0000402	0.0000813	Constant
D	3.00000	13.40000	Diameter
V	5.78000	7.24000	Velocity
rated	1.00000	40.00000	Rated turbine
h	10.00000	45.00000	Height

Pearson Correlation Coefficients, N = 32
Prob > |r| under H0: Rho=0

	k	D	V	rated	h
k Constant	1.00000	0.58848 0.0004	-0.36652 0.0391	0.52736 0.0019	-0.36056 0.0426
D Diameter	0.58848 0.0004	1.00000	0.00000 1.0000	0.99655 <.0001	0.00000 1.0000
V Velocity	-0.36652 0.0391	0.00000 1.0000	1.00000	0.00000 1.0000	0.98395 <.0001
rated Rated turbine	0.52736 0.0019	0.99655 <.0001	0.00000 1.0000	1.00000	0.00000 1.0000
h Height	-0.36056 0.0426	0.00000 1.0000	0.98395 <.0001	0.00000 1.0000	1.00000

Small Turbines Rated less than 50 kW

The GLM Procedure

Dependent Variable: k Constant

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	4	4.87743E-9	1.2193575E-9	776.88	<.0001
Error	27	4.237795E-11	1.569554E-12		
Corrected Total	31	4.9198079E-9			

R-Square	Coeff Var	Root MSE	k Mean
0.991386	1.941292	1.25282E-6	0.000065

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	0.0000261780	4.351412E-6	6.02	<.0001
D	0.0000299787	9.3041263E-7	32.22	<.0001
V	-.0000096318	4.6938166E-7	-20.52	<.0001
rated	-.0000081721	4.2830961E-7	-19.08	<.0001
d2	0.0000001785	5.0834327E-8	3.51	0.0016

Small Turbines Rated less than 50 kW

The REG Procedure
Model: MODEL1
Dependent Variable: k Constant

Root MSE	0.00000125	R-Square	0.9914
Dependent Mean	0.00006454	Adj R-Sq	0.9901
Coeff Var	1.94129		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	0.00002618	0.00000435	6.02	<.0001
D	Diameter	1	0.00002998	9.304126E-7	32.22	<.0001
V	Velocity	1	-0.00000963	4.693817E-7	-20.52	<.0001
rated	Rated turbine	1	-0.00000817	4.283096E-7	-19.08	<.0001
d2	diam sq	1	1.785192E-7	5.083433E-8	3.51	0.0016

Medium – Correlation

Medium Turbines Rated greater than 50 kW and less than 250kW

The CORR Procedure

6 Variables: k D V rated h d2

Simple Statistics

Variable	N	Mean	Std Dev	Sum
k	40	0.0000889	0.0000316	0.00356
D	40	21.28000	7.42094	851.20000
V	40	6.64000	0.47784	265.60000
rated	40	141.00000	81.23407	5640
h	40	27.50000	11.60239	1100
d2	40	506.53200	307.86023	20261

Simple Statistics

Variable	Minimum	Maximum	Label
k	0.0000573	0.0001628	Constant
D	10.40000	29.50000	Diameter
V	5.78000	7.24000	Velocity
rated	65.00000	250.00000	Rated turbine
h	10.00000	45.00000	Height
d2	108.16000	870.25000	d2

Pearson Correlation Coefficients, N = 40
Prob > |r| under H0: Rho=0

	k	D	V	rated	h	d2
k Constant	1.00000	-0.58982 <.0001	-0.16110 0.3207	-0.30523 0.0555	-0.15929 0.3262	-0.49380 0.0012
D Diameter	-0.58982 <.0001	1.00000	0.00000 1.0000	0.93443 <.0001	0.00000 1.0000	0.99164 <.0001
V Velocity	-0.16110 0.3207	0.00000 1.0000	1.00000	0.00000 1.0000	0.98395 <.0001	0.00000 1.0000
rated Rated turbine	-0.30523 0.0555	0.93443 <.0001	0.00000 1.0000	1.00000	0.00000 1.0000	0.97204 <.0001
h Height	-0.15929 0.3262	0.00000 1.0000	0.98395 <.0001	0.00000 1.0000	1.00000	0.00000 1.0000
d2 d2	-0.49380 0.0012	0.99164 <.0001	0.00000 1.0000	0.97204 <.0001	0.00000 1.0000	1.00000

Medium Turbines Rated greater than 50 kW and less than 250kW

The GLM Procedure

Dependent Variable: k Constant

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	5	3.8922977E-8	7.7845954E-9	2923.37	<.0001
Error	34	9.053796E-11	2.662881E-12		
Corrected Total	39	3.9013515E-8			

R-Square	Coeff Var	Root MSE	k Mean
0.997679	1.836068	1.63183E-6	0.000089

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	0.0002331700	0.00001347	17.31	<.0001
D	-.0000249859	0.00000120	-20.84	<.0001
V	-.0000106633	0.00000055	-19.50	<.0001
rated	0.0000039582	0.00000012	33.72	<.0001
rd	-.0000001295	0.00000000	-42.53	<.0001
d2	0.0000007103	0.00000004	16.34	<.0001

Medium Turbines Rated greater than 50 kW and less than 250kW

The REG Procedure
Model: MODEL1
Dependent Variable: k Constant

Root MSE	0.00000163	R-Square	0.9977
Dependent Mean	0.00008888	Adj R-Sq	0.9973
Coeff Var	1.83607		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	0.00023317	0.00001347	17.31	<.0001
D	Diameter	1	-0.00002499	0.00000120	-20.84	<.0001
V	Velocity	1	-0.00001066	5.468383E-7	-19.50	<.0001
rated	Rated turbine	1	0.00000396	1.173796E-7	33.72	<.0001
rd	rated*diam	1	-1.29499E-7	3.045115E-9	-42.53	<.0001
d2	diam sq	1	7.102996E-7	4.345872E-8	16.34	<.0001

Large Turbines

Large Turbines rated greater than 250 kW and less than 750 kW

The CORR Procedure

5 Variables: k D V rated h

Simple Statistics

Variable	N	Mean	Std Dev	Sum
k	80	0.0000748	6.08172E-6	0.00598
D	80	41.60000	5.78431	3328
V	80	7.16463	0.64171	573.17000
rated	80	580.00000	170.18233	46400
h	80	47.50000	23.19428	3800

Simple Statistics

Variable	Minimum	Maximum	Label
k	0.0000648	0.0000895	Constant
D	31.00000	48.00000	Diameter
V	5.78000	7.97000	Velocity
rated	300.00000	750.00000	Rated turbine
h	10.00000	85.00000	Height

Pearson Correlation Coefficients, N = 80
Prob > |r| under H0: Rho=0

	k	D	V	rated	h
k Constant	1.00000	0.02739 0.8094	-0.90969 <.0001	0.14625 0.1955	-0.90072 <.0001
D Diameter	0.02739 0.8094	1.00000	0.00000 1.0000	0.93819 <.0001	0.00000 1.0000
V Velocity	-0.90969 <.0001	0.00000 1.0000	1.00000	0.00000 1.0000	0.97257 <.0001
rated Rated turbine	0.14625 0.1955	0.93819 <.0001	0.00000 1.0000	1.00000	0.00000 1.0000
h Height	-0.90072 <.0001	0.00000 1.0000	0.97257 <.0001	0.00000 1.0000	1.00000

Large Turbines rated greater than 250 kW and less than 750 kW

The GLM Procedure

Dependent Variable: k Constant

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	4	2.7915614E-9	6.978903E-10	401.28	<.0001
Error	75	1.304382E-10	1.739176E-12		
Corrected Total	79	2.9219996E-9			

R-Square	Coeff Var	Root MSE	k Mean
0.955360	1.763095	1.31878E-6	0.000075

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	0.0001792675	7.9243091E-6	22.62	<.0001
D	-.0000022076	4.06494E-7	-5.43	<.0001
V	-.0000086215	2.3121778E-7	-37.29	<.0001
rated	0.0000000346	2.5586331E-9	13.51	<.0001
d2	0.0000000165	5.3003607E-9	3.11	0.0026

Large Turbines rated greater than 250 kW and less than 750 kW

The REG Procedure
Model: MODEL1
Dependent Variable: k Constant

Root MSE	0.00000132	R-Square	0.9554
Dependent Mean	0.00007480	Adj R-Sq	0.9530
Coeff Var	1.76310		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	0.00017927	0.00000792	22.62	<.0001
D	Diameter	1	-0.00000221	4.06494E-7	-5.43	<.0001
V	Velocity	1	-0.00000862	2.312178E-7	-37.29	<.0001
rated	Rated turbine	1	3.456631E-8	2.558633E-9	13.51	<.0001
d2	Diam sq	1	1.649311E-8	5.300361E-9	3.11	0.0026

Utility – Correlation

Utility Turbines rated greater than 750 kW

The CORR Procedure

5 Variables: k D V rated h

Simple Statistics

Variable	N	Mean	Std Dev	Sum
k	98	0.0000701	4.1642E-6	0.00687
D	98	70.88571	12.62785	6947
V	98	7.90529	0.30105	774.71800
rated	98	1593	568.86576	156100
h	98	81.98980	20.87938	8035

Simple Statistics

Variable	Minimum	Maximum	Label
k	0.0000613	0.0000795	Constant
D	52.20000	90.00000	Diameter
V	7.36000	8.34000	Velocity
rated	900.00000	2500	Rated turbine
h	50.00000	115.00000	Height

Pearson Correlation Coefficients, N = 98
Prob > |r| under H0: Rho=0

	k	D	V	rated	h
k Constant	1.00000	-0.15289 0.1329	-0.72757 <.0001	0.11761 0.2488	-0.70465 <.0001
D Diameter	-0.15289 0.1329	1.00000	0.00000 1.0000	0.89668 <.0001	0.03203 0.7542
V Velocity	-0.72757 <.0001	0.00000 1.0000	1.00000	0.00000 1.0000	0.98424 <.0001
rated Rated turbine	0.11761 0.2488	0.89668 <.0001	0.00000 1.0000	1.00000	0.02790 0.7851
h Height	-0.70465 <.0001	0.03203 0.7542	0.98424 <.0001	0.02790 0.7851	1.00000

Utility Turbines rated greater than 750 kW

The GLM Procedure

Dependent Variable: k   Constant

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	1.6700745E-9	2.783457E-10	2117.45	<.0001
Error	91	1.196227E-11	1.314536E-13		
Corrected Total	97	1.6820368E-9			

R-Square	Coeff Var	Root MSE	k Mean
0.992888	0.517533	3.62565E-7	0.000070

Parameter	Estimate	Standard Error	t Value	Pr > |t|
Intercept	0.0005694858	0.00001280	44.48	<.0001
D	-.0000208645	0.00000064	-32.62	<.0001
V	-.0000100639	0.00000012	-82.30	<.0001
rated	0.0000004543	0.00000001	33.38	<.0001
rd	-.0000000050	0.00000000	-28.56	<.0001
d2	0.0000001870	0.00000001	30.62	<.0001
r2	-.0000000000	0.00000000	-16.82	<.0001

Utility Turbines rated greater than 750 kW

The REG Procedure
Model: MODEL1
Dependent Variable: k Constant

Root MSE	3.625653E-7	R-Square	0.9929
Dependent Mean	0.00007006	Adj R-Sq	0.9924
Coeff Var	0.51753		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	0.00056949	0.00001280	44.48	<.0001
D	Diameter	1	-0.00002086	6.397031E-7	-32.62	<.0001
V	Velocity	1	-0.00001006	1.222819E-7	-82.30	<.0001
rated	Rated turbine	1	4.54316E-7	1.361062E-8	33.38	<.0001
rd	rated*daim	1	-5.04175E-9	1.76534E-10	-28.56	<.0001
d2	diam sq	1	1.869958E-7	6.107461E-9	30.62	<.0001
r2	rated sq	1	-1.1286E-11	6.71071E-13	-16.82	<.0001

APPENDIX F. COMPARISON OF PAYBACK PERIODS

Pay back Period	Model 1	Model 2	Model 3	Model 4
Scenario A[1]	$t_B > 25$	$t_B > 25$	$t_B > 25$	$t_B > 25$
Scenario B[2]	$t_B = 4$	$t_B = 4$	$t_B = 6$	$t_B = 6$
Scenario C[3]	$t_B = 6$ $t_B > 25$	$t_B = 3$	$t_B > 25$	$t_B = 11$
Scenario D[4]	$t_B = 1$	$t_B = 1$	$t_B = 2$	$t_B = 2$

[1] 1000 kW turbine, 60 meter rotor diameter, 60 meter height, wind speed of 7.18 m/s
[2] 1500 kW turbine, 80 meter rotor diameter, 80 meter height, wind speed of 8.02
[3] 1000 kW turbine, 60 meter rotor diameter, 60 meter height, wind speed of 7.18 m/s, 30 percent 3rd party investment, $50,000 Excess depreciation, $75,000 Passive income
[4] 1500 kW turbine, 80 meter rotor diameter, 80 meter height, wind speed of 8.02 m/s, 30 percent 3rd party investment, $50,000 Excess depreciation, $75,000 Passive income

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