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Economic Analysis:

Co-generation Using Wind and Biodiesel-Powered Generators

by

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Executive Summary

This study was undertaken to determine the economic feasibility of complementing electricity generated by wind with electricity generated by diesel gensets using various blends of biodiesel. An investment model was developed to estimate whether adding a genset, which increases the investment, revenue and operating costs will enhance the economic viability of generating electricity with a wind turbine. The investment model provides a tool that can be used to answer this question for sites with various wind characteristics and with alternative sources of revenue.

Existing regulations and tariffs in Minnesota and other parts of the U.S. establish preferences for power generated from wind and other renewable sources. The price typically paid for wind energy in Minnesota is $.033 per KWH, but owners of wind turbines are eligible for several additional sources of revenue. The federal Production Tax Credit (PTC) of 1.9 cents per KWH is a second source. Utilizing this credit may require an investor/partner on a wind project with sufficient passive income tax liability to utilize this credit over the first ten years of the project. In addition, a Minnesota state incentive payment of 1.5 cents per kilowatt-hour is available for ten years on wind projects of 2.0 Megawatts or smaller, subject to statewide subscription levels. Production of electricity from wind may also result in the creation of tradable renewable credits or "green-tags," which may have value to utilities subject to state renewable energy standards.

The variable nature of electrical power capacity from wind has been problematic for utilities, which try to meet the variable loads required by the summed demand of their customers. In addition to payments per kilowatt-hour produced by wind or other renewables, attractive capacity payments are offered by utilities when renewable sources can supply 65% "firm" power during "On-Peak" hours which are typically 9:00 a.m. through 9:00 p.m., Monday through Friday, excluding holidays for the months June through September.

The key task of this project is to determine if electricity derived from wind can be economically complemented with electricity generated by diesel generators or gensets using biodiesel, another renewable fuel. Biodiesel is a fuel that can be derived from vegetable oils or animal fats and can be used neat (100%) or in various blends with petro-diesel. With the passage of the American JOBS Creation Act of 2004, the federal biodiesel tax credit has the effect of lowering the price of biodiesel blends to the price of petro-diesel through 2008. Without the biodiesel tax credit in 2009 and beyond, the cost of B55 and B75 biodiesel blends (required to qualify as renewable power) will increase substantially. Electricity produced by diesel generators or gensets is typically much more expensive than electricity produced from wind or other sources; however, the electricity produced by the combination of

wind and biodiesel generators may qualify as "firm" power and be eligible for capacity payments if considered a single "qualifying facility."

Net present values (NPV) and internal rates of return (IRR) are calculated over the life of power production projects conforming to various conditions such as wind capacity factor, biodiesel costs, biodiesel blends utilized, and the number of hours required to back-up wind power. In addition the costs of electricity produced from wind alone and when complemented with a genset powered with various blends of biodiesel are calculated.

The analysis reveals that wind turbines with capacity factors 35% or better can be complemented with diesel gensets powered with B75 biodiesel to provide power 65% firm for June-September during on-peak hours and maintain overall IRR's greater than 9.0% as long as the Federal Biodiesel Tax Credit is in effect. However, without the Biodiesel Tax Credit, wind sites with capacity factors of 35% are unable to produce power and achieve a 9.0% IRR, when operating over 320 hours per year using B75 blends with fuel priced at $1.80 and $2.60 for diesel and biodiesel, respectively. Complementing wind sites with diesel gensets does not make wind power more competitive on lower capacity factor sites. Hybrid systems using gensets powered with biodiesel blends should only be considered on sites with capacity factors of 40% or better to guard against the risk that the Biodiesel Tax Credit may be removed. The opportunity to firm power produced by wind may make inclusions of wind power more attractive to power companies, although the creation of wind-biodiesel genset hybrids represents an untested concept as a "qualifying facility" in the regulatory framework.

Appendices have been added to this paper following review by an outside party who commented on the paper written, the original assumptions established, and the conclusions (Appendix 1.0). In Appendix 2.0 the original authors respond to the review by modeling some additional assumptions of interest including the use of a single rate ($.038 per kWh) to be paid on electricity derived from the wind turbine and the diesel genset. In addition, capacity payments were calculated for a modeled qualifying facility achieving 65% firm power for the same June-September period as the additional study as well as for five and six month periods that include May and October. Appendix 3.0 contains final comments of the reviewer. Appendix 4.0 contains an analysis of the proposed pilot project that will test the use of B100 biodiesel in a genset based on the prevailing price of biodiesel after utilizing the Biodiesel Tax Credit. Following the pilot trial, the engine of the genset will be torn apart by mechanical engineers to permit analysis of engine parts after operation using neat (B100) biodiesel.

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Introduction

Electrical generation capacity from wind has grown rapidly in the U.S. in recent years as reflected in **Figure 1**. Despite the rapid growth and high visibility, wind remains a small portion of total electrical energy consumed in the U.S., as shown in **Figure 2**. In reviewing this data, it is important to distinguish between capacity to produce power and the actual production of power. U.S. and Minnesota wind capacity has been developed in response to the federal production tax credit (PTC), which currently offers ten years of income tax credits that can be applied toward passive income. Additional state incentives such as the Minnesota Wind Production Incentive for small wind projects (less than 2.0 MW), and Minnesota statutes that compel Xcel Energy to purchase targeted quantities of renewable energy have encouraged wind development in Minnesota.

Figure 1.

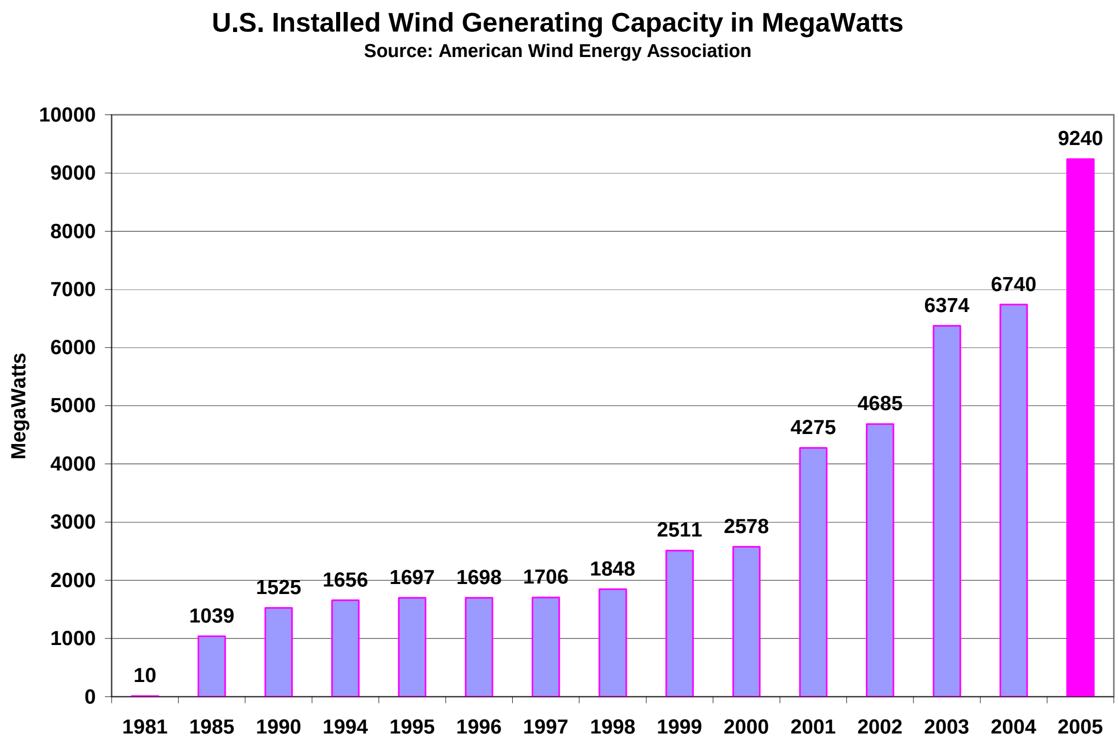
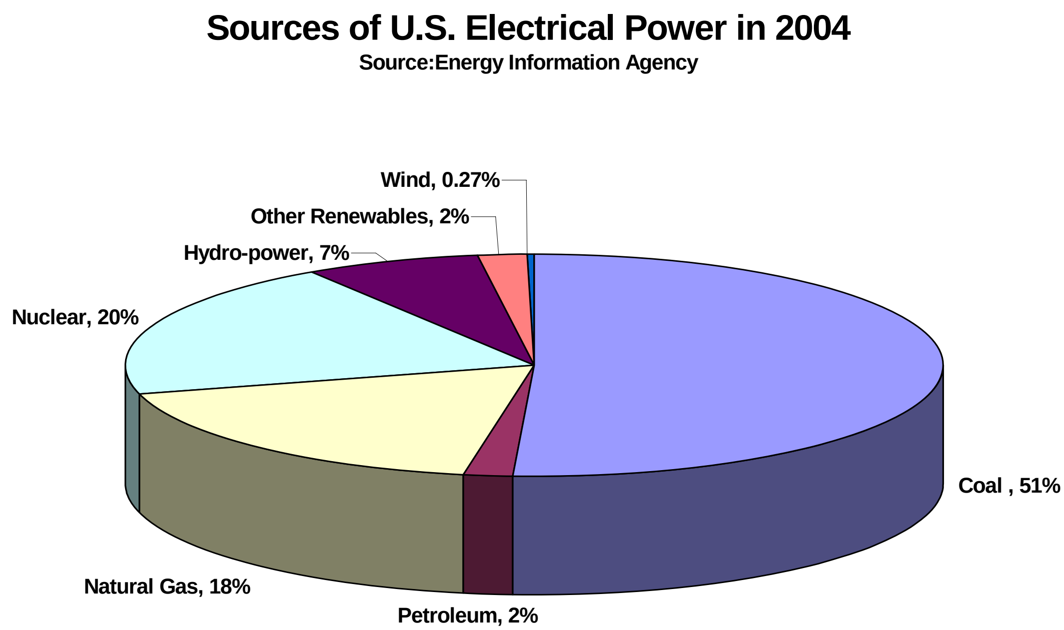


Figure 2.



Policy, Economic, and Technical Drivers of Wind

Wind electrical generation capacity in Minnesota has been assisted by the interplay of state and national factors starting with policy drivers, which are closely related to economic incentives, and then improvements in knowledge and equipment. The following listing segregates and highlights the importance of some of these factors currently and in the future:

Policy Drivers

1) Public Utilities Regulatory Policy Act (PURPA) legislation that requires utilities to accept wind and other renewable sources of electricity at "avoided costs,"
2) Federal Energy Regulatory Commission (FERC) policies that foster greater access to the grid by renewable energy,
3) Strong interest shown by individuals and groups to support the establishment of renewable power sources, including wind,
4) State goals to mandate local wind energy and other renewable energy sources versus purchases of electricity derived from fossil fuels or from other states or nations and
5) Investigation of regulatory barriers that reduce utilization of windpower.

Economic Drivers

1) U.S. policy establishing and maintaining the wind production tax credit (PTC), now extended through 2007 at 1.9 cents per kWh for ten years of production,
2) State of Minnesota Wind Incentive payments of 1.5 cents for ten years of production of projects less than 2.0 MW in size,
3) Growth in experience by bankers in financing wind energy development projects,
4) Experience in marketing wind-derived energy in response to corporate goals and consumer demand for "green" energy and
5) Growth in experience by lawyers in negotiating and executing power purchase agreements between wind producers and utilities.

Technical Drivers

1) State of Minnesota's public investments to assess wind resources around the state,
2) Increasing sophistication in design and engineering of wind turbines; especially international experience in Germany, Denmark, and Spain, and
3) Greater research in conductors capable of increasing capacity in transmission lines from remote wind sites to load centers.

Environmental Factors Favoring Wind Energy

The various drivers cited above are strengthened by wind-derived electricity's reputation as a clean source of electrical power. If national policy or international policies should emerge that favor the reductions in greenhouse-producing gases, windpower will certainly gain due to potential charges on emissions from fossil sources or corresponding increases in "green" energy credits. Appearing below in **Figure 3** are the amounts of carbon dioxide, sulfur dioxide, and nitrogen oxides released in the process of producing a kilowatt-hour by various methods.[1]

Figure 3.

Pounds of Emissions per KWH of Electricity Generated in U.S.

Source: EIA Annual Energy Review 1998

Fuel	CO2	SO2	NOx
Coal	2.13	0.013400	0.0076
Natural Gas	1.03	0.000007	0.0018
Oil	1.56	0.011200	0.0021
U.S. Average Mix	1.52	0.008000	0.0049
Wind	0	0	0

[1] Wind Energy Fact Sheet, American Wind Energy Association, EIA Annual Energy Review 1998. http:www.eia.doe.gov/aer>

Economic Issues Facing Wind Energy

Despite the favorable influences and drivers that have hastened the growth in wind energy in recent years in Minnesota, there are substantial economic issues that must be surmounted before greater portions of total electrical capacity can be replaced by wind.

Key among the problems is the economic inertia that faces any alternative energy source. An operating system exists that functions very efficiently and supplies electricity very cheaply. Tremendous investments have been made by utilities to supply homes, commercial enterprises, and industries with the amount of energy needed, when it is needed. Power-generating facilities, whether coal-fired or nuclear are located at strategic locations to produce power that can be readily distributed through the continental electrical grid from the sources where produced to the places where needed. The firms generating electricity from conventional sources and transmitting that power have obvious self-interests to protect their investments in installed capacity.

Electricity is unique as a commodity because of its inherent property of flowing to sites where demanded and at the speed of light. The North American electrical grid permits utilities to automatically bid and receive power from the lowest cost supplier in real time. Few other commodities that improve the quality of life have these inherent qualities or are available in such a market. Because this market and the North American grid permit the sale of power at favorable prices, it is often difficult for renewable sources, such as wind, to compete against cheap coal and conveniently located natural gas powered generators. **Figure 4** allows one to compare the relative costs per kilowatt-hour of electricity generated by various fuels and by wind as projected by the U.S. Energy Information Agency for 2015.

Figure 4.

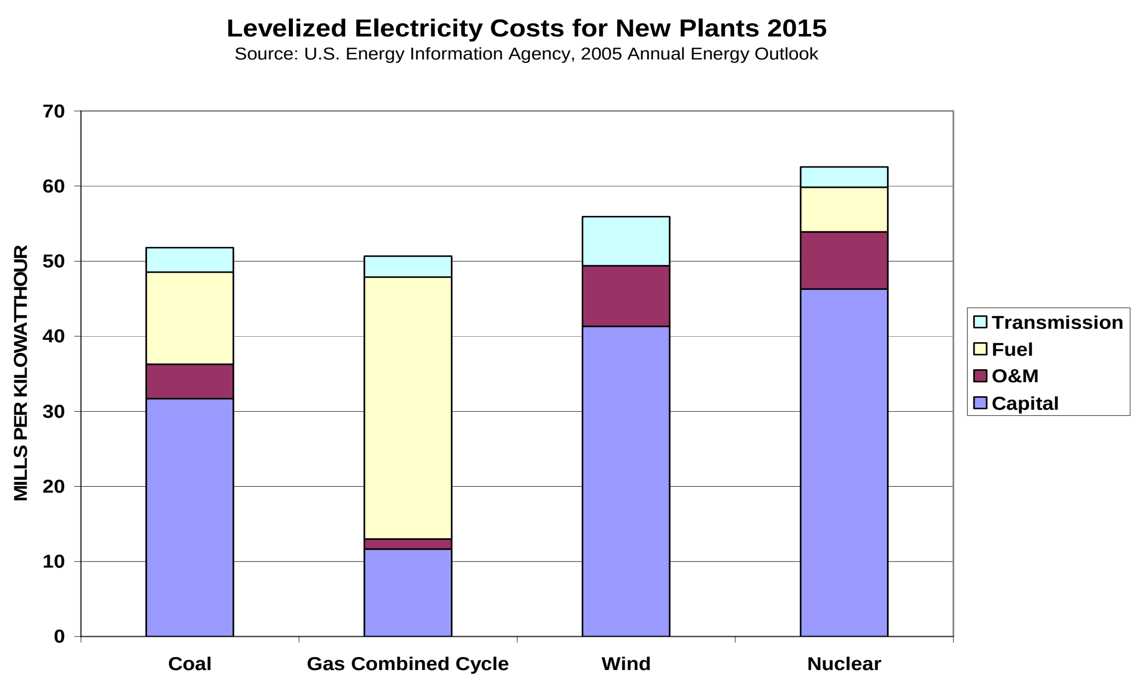


Figure 4 shows that natural gas used in a combined cycle generator has the lowest levelized cost per kilowatt-hour, and lowest capital costs, but costs for this source of power have the highest fuel cost component. Mistaken assumptions about natural gas costs over the next ten years could easily reverse these rankings. Coal-fired generators produce power with slightly higher overall costs than natural gas, but have capital costs nearly three times greater and with much lower cost for fuel than natural gas. The levelized cost of electricity derived from wind has higher capital cost per kilowatt-hour produced than both coal and natural gas with operations and maintenance expenses approximately twice as high as coal. Windpower has no fuel cost, but transmission costs are higher due to the fact that the best wind resources in the U.S. are generally quite distant from load centers. Nuclear power plants have the highest levelized cost due to higher capital costs than wind, similar O & M expenses as wind, modest fuel costs and transmission costs intermediate between natural gas and coal. A conclusion to be drawn from this generalized outlook is the competitiveness of wind in producing electricity versus coal and natural gas. Each of the four sources of power has its particular challenges. Natural gas has recently faced fuel cost volatility. Coal requires much higher capital costs due to necessary scrubbers and uses a fuel that contributes higher emissions of carbon than the other choices. Wind has high up-front capital costs and higher transmission costs than the major alternatives compared. Nuclear power plants face high capital costs due to safety requirements as portrayed in the graph as well as potentially legal and regulatory battles in siting future plants.

Electricity has a fundamental problem as a commodity in that it needs to be generated concurrently with its use. Technologies to store electricity, such as batteries, are undeveloped or too expensive to overcome the need to produce power as needed. Liquid fuels and natural gas can be cheaply transported by pipelines. Liquid fuels can be stored in tanks where needed; and natural gas can be pressurized and stored in caverns until needed. In contrast, electricity must be generated in the right amount at the right time to fulfill the requirements of the aggregated end users, who just flick a switch to receive more. Tremendous investments have occurred to balance the supply of electricity available in the North American electrical grid with computers and other equipment that prompt numerous generators to produce the proper amount of electricity at the right time.

A satellite view of Minnesota reveals a network of railroads that transport low-sulfur coal to some large electrical generating plants. A similar view would show a pipeline system that transports natural gas from Canada and the Gulf States to Minnesota generators using this fuel. In addition, transmission lines from mine-mouth coal plants in North Dakota and Wyoming provide a significant portion of the electricity available for Minnesota users. Transmission lines are also important in transporting hydro-electric power from Ontario and Manitoba to Minnesota. Minor amounts of hydro-power and other renewable sources of electricity exist in Minnesota with the exception of wind.

In addition to facing economic inertia in markets supplied by mature technologies that supply their customers quite cheaply, wind power has two problems that are uniquely its own.

1) Wind and electrical power derived from it is a <u>variable</u> "flow resource."
2) Because such a small proportion of electrical power demand occurs in the areas of Minnesota and neighboring states with the best wind resources, constraints on transmission capacity and existing rules limit access for wind on the transmission grid.

It is with this background that this project was initiated to investigate a means by which the wind resources of Minnesota can be more fully utilized in a fashion compatible with power demand.

Objectives

This project was proposed in order to assess the economic feasibility of complementing variable, renewable electricity from wind with largely renewable "dispatchable" electricity generated by diesel generators or gensets. As proposed, the gensets would be fuelled with various blends of biodiesel, a renewable fuel with an excellent energy balance and emissions characteristics more favorable than petro-diesel. The primary objectives of this project were to determine the financial performance and blended cost of the energy from wind turbines complemented with biodiesel-powered gensets. Fundamental to this purpose was the understanding of the applicable rules for pricing and accepting electricity supplied by wind and other renewable sources of energy on the transmission grid. Power purchase tariffs recorded by Xcel Energy with the Minnesota Department of Commerce offered guidance on potential payments for power produced as well as payments for capacity. Development of capital and operating costs for wind turbines and gensets using biodiesel blends preceded analysis with an investment model.

Literature Review

The study in rural Texas[2] by Eggleston and Clark demonstrated use of a small wind generator to supplement power provided by a diesel generator. The diesel generator used either #2 diesel or biodiesel as fuel. The research was directed toward learning the ability of wind to save fuel in diesel generators dedicated to power production in a village situation. The researchers found that 5.4% more biodiesel than #2 diesel was needed on average per kilowatt-hour. This hybrid system resulted in 18% fuel savings over 800 hours of testing.

A multi-year project in the remote village of Wales, Alaska by National Renewable Energy Laboratory (NREL) researchers, Drouihet and Shirazi [3] sought to determine the economics of using wind to reduce fuel usage and cut costs in a village totally reliant upon on-site electrical generation by diesel. Because of its remote location, the delivered cost of diesel fuel was very high, ranging from $1.00 to $3.00 per gallon, making for very expensive electricity. Equipment for this village of 160 people and an average electric load of 75 kW included two wind turbines totaling 130 kW and three diesel gensets totaling 411 kW. In addition this project included substantial batteries, a battery charger, a rotary converter and also local and remote dump load controllers in order to have greater control over the power output from the various sources. Much of the research was directed toward determining statistical measures to guide management of the various components of this system at various times and balance the system to the load.

The third key study reviewed was by McGowan, et al [4] and involved the pending installation of four turbines of approximately 4.0 MW to supplement 15 diesel gensets providing up to 22.8 MW diesel electricity plant at Guantanamo Bay, Cuba. Hybrid2 software was used to estimate the potential contribution of the wind turbines to the base's energy needs as well as the cost savings of very expensive diesel fuel delivered to this location. In addition, the researchers were interested in avoiding substantial emissions of NOx, SOx, CO2, and particulates. Average full-load fuel use in the diesel engines typically used (ranging from 900 kW to 2500 kW) was 80 gallons per MWh or about 30-32% efficiency. One conclusion of the study is that when wind penetration increases, greater savings can occur in diesel fuel; however, more complex controls and expensive equipment will be needed. At peak power output the wind turbines will produce from 20-25% of the base's electric demand and displace the greenhouse gas emissions of over 13,000,000 pounds of carbon dioxide from the diesel generators. Installation of the four turbines at Guantanamo Bay makes this base the world's largest wind-diesel hybrid utility.

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[2] Eggleston, Eric and R. Nolan Clark, "Wind/Diesel and Wind Biodiesel Performance of the USDA Hybrid System," USDA, Agricultural Research Service. 1998.
http://www.biodiesel.org/resources/reportsdatabase/reports/gen/19980601_gen-268.pdf

[3] Drouilhet, S and M. Shirazi, "Wales, Alaska: High-Penetration Wind-Diesel Hybrid Power System," National Renewable Energy Laboratory, NREL/TP-500-31755, May 2002.

[4] McGowan, et. al. "Wind Power at Guantanamo Bay: A Hybrid Wind-Diesel System," University of Massachusetts, Renewable Energy Research Laboratory, Amherst, MA. Presented at American Wind Energy Association's Global Windpower 2004 Conference. March 30, 2004.

Background and Methods

The amount of electricity generated and the profitability of investing in a combination wind turbine and genset is highly dependent on the wind energy available at the site selected. As we show later in this paper, the cost of producing electricity with a genset is typically greater than the cost of producing electricity with a wind turbine. Investors want to select a site with wind characteristics that enable the wind turbine to provide power during a high proportion of the on-peak hours (typically 9:00 a.m. to 9:00 p.m. Monday through Friday during June through September). With more hours of wind turbine operation, fewer hours of genset operation are required to provide 65% firm power during the on-peak hours and qualify for capacity payments.

Some of the considerations in site selection, operation of wind turbines and operation of diesel genset operation are mentioned here as background for the analysis. Then it is time to describe the analytical tool selected to determine how well biodiesel-powered gensets can complement wind turbines.

Wind Energy and Sites for Wind Turbines

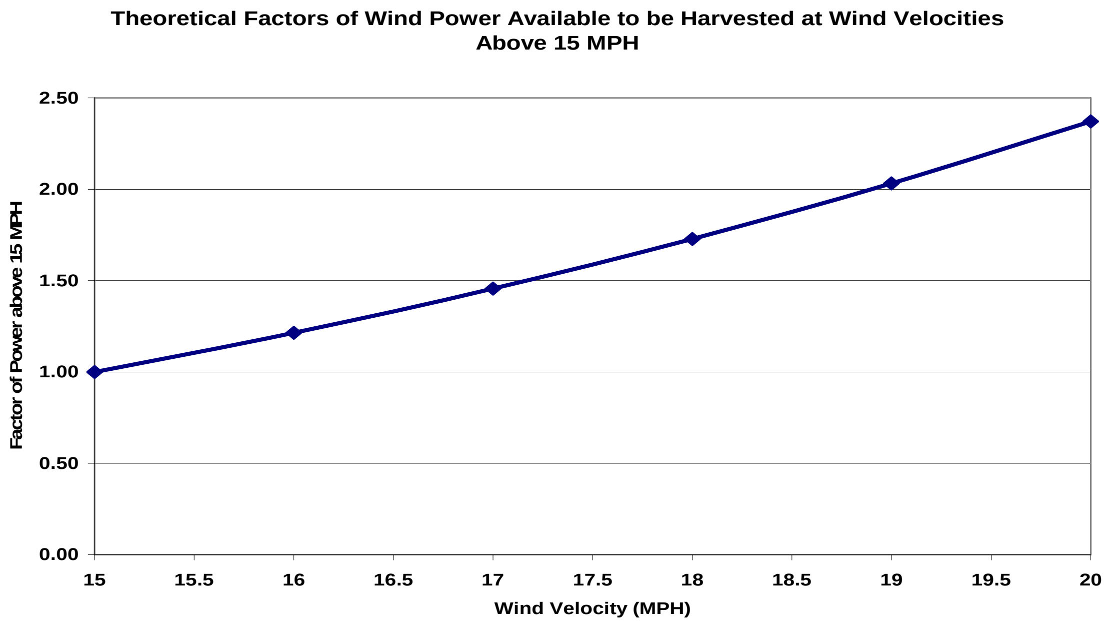
Wind turbines are designed to convert the kinetic energy of wind moving its blades into direct current electrical power. The formula for the power of wind in English units appears below[5]:

Power =1/2 pAV^3 where p is air density
A is swept area of blades
V is wind velocity

Because the power available to generate electricity is a function of wind velocity cubed, relatively small increases in wind velocity result in substantial increases in power available to move the blades of a turbine. This factor in the formula makes selection of wind development sites with the highest possible annual wind velocity such a critical activity. **Figure 5** shows the theoretical factors of increase in power above that at 15 miles per hour in the area swept by a wind turbine for higher wind velocities. This helps explain why individuals and firms developing wind sites go to considerable expense and perform detailed analysis to select sites with the best possible wind velocities in an area. One can see from this graph that a site with a wind velocity of 17 mph is approximately 50% better than one with a wind velocity of 15 mph. Similarly a site with wind velocity of 19 mph should have twice the power of one with 15 mph. The term for air density in the formula tells us that cooler, denser air is capable of moving the blades of a wind turbine to a greater degree than warm air. One should remember that wind turbines can not be designed to capture very high portions of the theoretical power in the wind, but must always allow a certain volume of wind to pass by the turbine blades.

[5] "Wind Energy Manual." Iowa Energy Center, 2000, p. 11. Website: http://www.energy.iastate.edu/renewable/wind/wem/wem-01_print.html., viewed 10/27/2004

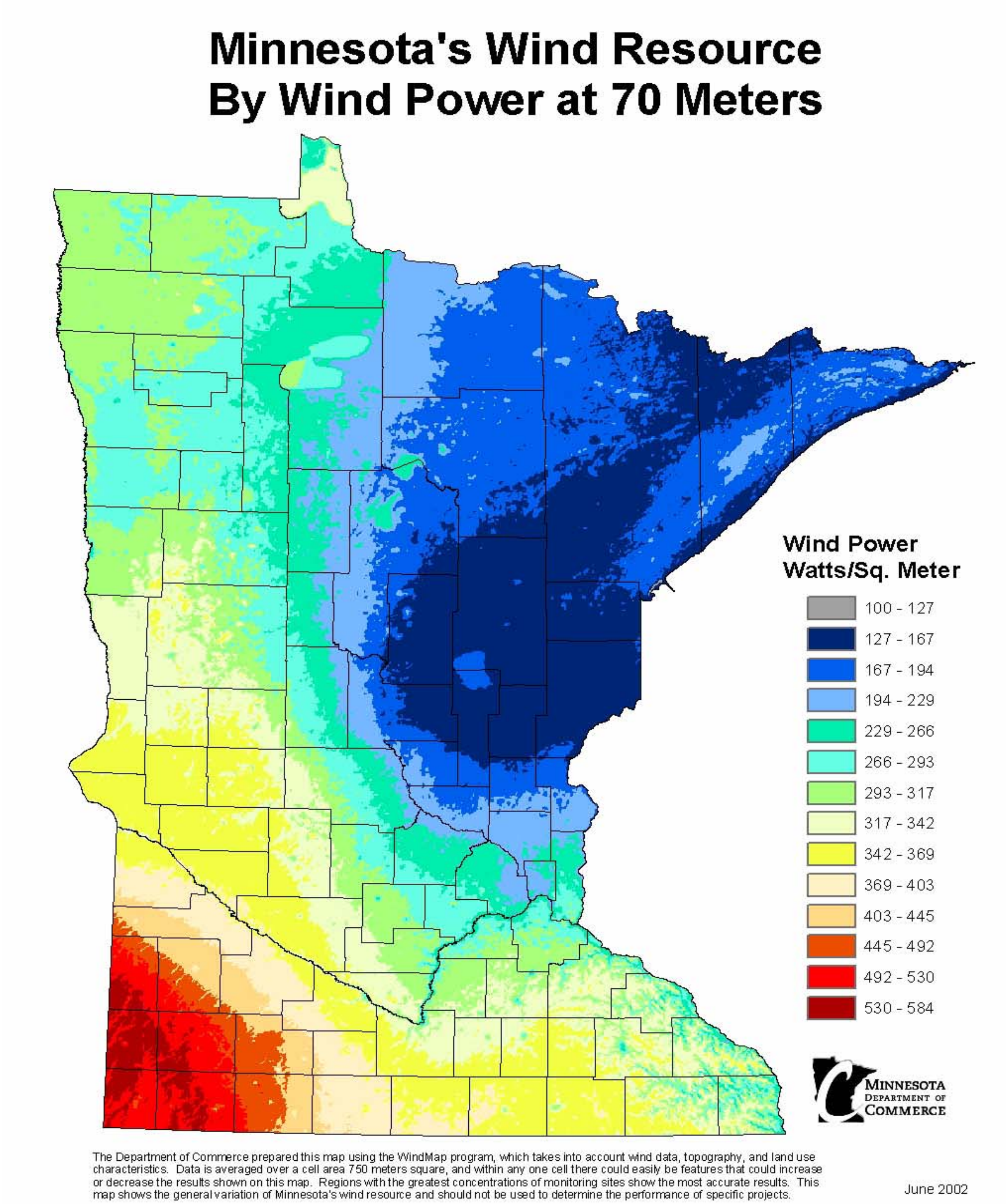
Figure 5.



A site with favorable wind velocity also needs to be located in an area with access to the power grid. To develop a successful wind energy project, additional effort and expense must be made to determine favorable locations, as will be discussed further in a section of this paper discussing the capital costs of wind turbines.

Wind developers are like mineral prospectors to the extent that they study maps and gather data in order to find sites that have the most reliable wind resources of sufficient strength to be utilized. The map on the following page, **(Figure 6)** shows in a generalized fashion, the wind power levels for Minnesota. The Minnesota Department of Commerce directed the development of this map following the collection of massive amounts of wind data. This map and other related public expenditures have certainly enhanced wind project development in Minnesota. The units mapped are in Watts per square meter of swept area of wind turbine blades at a hub height of 70 meters, which is a typical height for many modern, utility scale wind turbines.

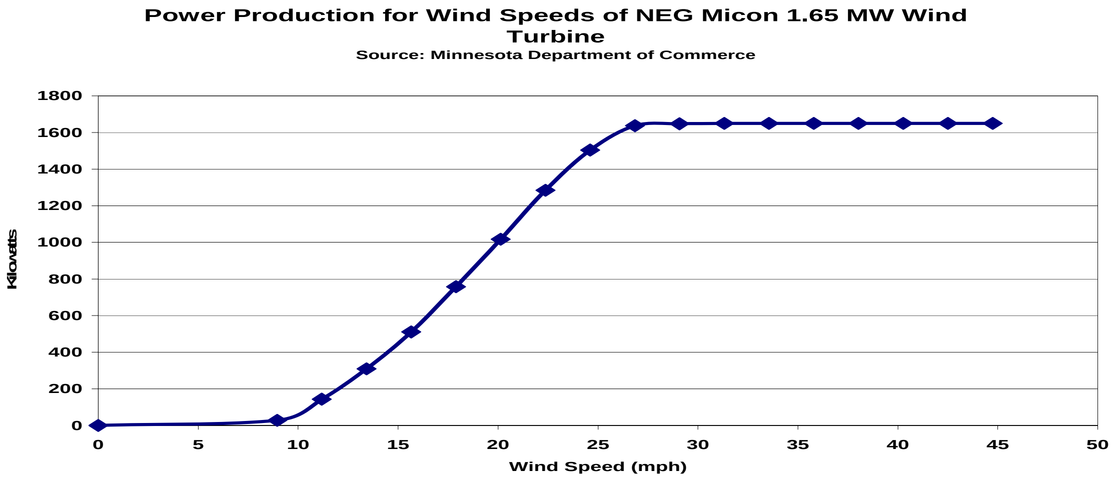
Figure 6.


Minnesota's Wind Resource
By Wind Power at 70 Meters
Wind Power
Watts/Sq. Meter
100 - 127
127 - 167
167 - 194
194 - 229
229 - 266
266 - 293
293 - 317
317 - 342
342 - 369
369 - 403
403 - 445
445 - 492
492 - 530
530 - 584
MINNESOTA DEPARTMENT OF COMMERCE
The Department of Commerce prepared this map using the WindMap program, which takes into account wind data, topography, and land use characteristics. Data is averaged over a cell area 750 meters square, and within any one cell there could easily be features that could increase or decrease the results shown on this map. Regions with the greatest concentrations of monitoring sites show the most accurate results. This map shows the general variation of Minnesota's wind resource and should not be used to determine the performance of specific projects.
June 2002

Operation of Wind Turbines

All wind turbines that have been built have a power curve, which represents the ability of that particular design to convert the kinetic energy of wind into electrical power. **Figure 7** shows the power levels a specific wind turbine model is capable of producing at various wind speeds. Consideration of the relationship between wind speed and power generated helps one understand the importance of designing turbines capable of producing power at low wind speeds as well as the ability to keep producing energy at high wind speeds. In recent years the major wind turbine manufacturers have been able to improve (lower) the wind velocity when a wind turbine reaches maximum power.

Figure 7.



Several points about the power curve are important for our analysis. Below certain wind speeds, no electricity is produced. The minimum wind velocity that can produce electricity is called the "cut-in" velocity, which is shown as 10 miles per hour on the graph above. The turbine blades turn at speeds from 14 to 29 revolutions per minute, depending upon the model. At higher wind speeds, power output increases until the nameplate output capacity of 1.65 Megawatts is reached near 27 miles per hour. As the graph shows, the output will stay at the same output level with higher and higher wind speeds until a cut-out speed is reached. The cut-out wind speed is often around 55 to 65 mph on many models and is the point where the wind turbine sets a brake to bring the blades to a stop for protection. In addition, the blades are rotated 90 degrees out of the wind and parked. After the wind drops back below cut-out velocity as detected by the on-board anemometer for a designated period of time, the turbine's yaw control turns the blades back into the wind and the brake is released. Soon the blades will spin back to operating speed and the turbine will again produce power. [6]

[6] "Harvesting the Wind," Energy and Environment Research Center. http://www.undeerc.org/wind/literature/wind_brochure.pdf. Viewed May 2, 2005)

Discussion of Capacity Factors

Every place on the map is unique with respect to its capability to generate wind power. When the engineered capabilities of a wind turbine are combined with the wind resource of a particular site, we have the ability to determine capacity factor for annual operation of a wind turbine. The rating of the wind turbine as well as the strength and duration of the wind combine to determine capacity factor. If a 1.65 Megawatt wind turbine produces 5,058.900 kilowatt-hours during the 8760 hours in a year, we can describe this site and turbine pair as having a capacity factor of 35%. [(5,058,900) /(1650 X 8760) = 35%] This means that the particular wind turbine produced 35% of its rated output at that site in a particular year. In the analysis to follow, project economics for wind sites ranging from 25% to 50% capacity factor will be analyzed. Each year the site and wind turbine will experience somewhat different patterns of wind strength and duration, so the capacity factor, or the opportunity to convert the wind to electrical power by that particular turbine will also vary.

Operation of Diesel Gensets

Gensets are assembled in factories and transported to suitable locations for operation. Caterpillar offers diesel generators rated from 7 to 16,200 kilowatts and with the reputation of running from 15,000 to 40,000 hours between major overhauls, depending upon the duty cycle. Considering that there are 8760 hours in a year, that's 1.7 to 4.5 years of continuous service. Reports from industry are that some diesel gensets have gone through six or more major overhauls in their lives.[7] Diesel gensets are rated for output based on three operating conditions, which are standby, prime power, and continuous duty. In the case of an appropriately-sized genset to complement the 1650 kW wind turbine, the output levels are adjusted by changing the revolutions per minute of the engine to produce 2000 kW, 1800 kW, and 1600 kW for standby, prime, and continuous operation, respectively. Gensets in standby operation go from zero to full load in ten seconds with an appropriate cool-down time of ten minutes at the end of their operation. Gensets operated under prime and continuous service receive time to warm-up the engine and gradually ramp-up the generator in advance of full load as well as appropriate cool-down time at the conclusion of their operation.[8]

In a situation such as contemplated in this study, it is necessary to include fuel tanks and a building for the genset and pay for necessary improvements to link a genset site with the power grid. Among the features on a diesel genset are controls to automatically synchronize and parallel the output of the generator with another source. In addition these machines have controls that facilitate smooth transitions of output on and off the utility grid because they are often standby and emergency power units.

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[7] Personal Interview: Paul Meyer, Ziegler Caterpillar, Shakopee, MN

[8] Ibid.

Overview of the Wind-Genset Workbook

The economic analysis in this project uses an investment model in an electronic workbook that portrays capital costs, revenues, and expenses over the life of a wind turbine of known capacity as well as a diesel genset of the same capacity. Separate spreadsheets were established for the wind turbine and diesel genset. With this technique, relevant conversion factors such as the gallons of #2 Diesel, B55 or B75 biodiesel blends needed to produce particular quantities of kilowatt-hours of electricity over a period of time were determined. In addition, the necessary capital costs and operating expenses are documented for the two methods of generating electricity. A broad range of operating parameters can be tested with this tool in order to understand the sensitivity of resulting electricity costs to various factors such as fuel costs or wind capacity factors for particular sites. As is true of many economic analyses, significant efforts were required to gather supporting budget data for the two methods of generating electricity.

The workbook consists of two spreadsheets that establish specifications and assumptions of operating 1) a wind turbine established on a site and 2) a diesel genset capable of completely replacing the output of that wind turbine. In each case capital costs and operating costs were sought for representative units. The “Genset” sheet also contains summary information from the “Wind” worksheet in order to calculate blended energy costs. The two linked spreadsheets for the two methods of producing power can be readily altered to conform to various assumptions about revenue streams, capital costs and operating expenses over the lives of the investments.

Data Sources

In addition to the review of literature that featured wind complemented by diesel gensets, other studies and data were gathered to complete this economic analysis. Among these studies were several that involved testing of biodiesel blends in diesel generators or gensets, particularly to understand the performance and emissions resulting from use of biodiesel blends. Price histories were reviewed of the cost of petro-diesel fuel as well as the cost of feedstocks that are essential to determining the cost of biodiesel. Without the prevailing federal Biodiesel Tax Credit, biodiesel derived from cheaper feedstocks such as yellow grease and lard can be produced more cheaply than biodiesel derived from vegetable oils, such as soy oil.

Published tariffs for the purchase of electricity from renewable sources were studied to determine appropriate levels of pricing for blended electricity from wind and biodiesel sources. Guidelines contained in PURPA were first developed during the higher energy prices experienced during the Carter Administration and were designed to give renewable sources of electricity access to the electrical power grid. Since that time efforts in Minnesota and other states have refined the definitions of qualifying facilities (QF's) for purposes of offering particular tariffs for power generation. Further refinements and regulatory definitions can be expected in the future.

A key body of wind turbine production data that was analyzed was made available by Minnkota Electric, a power producing cooperative that is owned by and serves several rural electric service cooperatives in Minnesota, North and South Dakota. Minnkota Electric maintains and records the hourly power production of two wind turbines installed several years ago.

Discussion of Wind Data

As a public service Minnkota Power maintains a website with power production data for their Valley City and Petersburg turbines since they have been in operation.[9] **Figure 8** shows the actual monthly production recorded for two identical 900 kW wind turbines located on two different sites approximately 90 miles apart in North Dakota and operated by Minnkota Power in 2004. **Figure 9** provides further detail regarding the production of power at the two sites, including the monthly capacity factor of each turbine for each month. The availability percentage recorded for each month gives some indication of the amount of time the wind turbines are out of service or in need of repair. When considering annual production, the Valley City and Petersburg sites are remarkably close with 2784 MWh and 2824 MWh produced, respectively. Although each turbine had higher production than its twin in certain months, their annual capacity factors were 35.3% and 35.8% for Valley City and Petersburg, respectively in 2004. Evident in the graph are the lower levels of power production from wind in June, July, August, and September. This pattern can be particularly troubling for utilities because the summer months are firmly established as the times of peak power demand in most areas of the U.S. In addition, peak production of power exceeded nameplate during winter months

[9]Minnkota Power, 2004 Statistics. Website: http://www.minnkota.com/Pages/InfinityMonthly.htm, viewed August 1, 2005

with colder, denser air and higher winds. The highest monthly capacity factor of 49% was recorded in November, 2004 at Petersburg, ND. The same turbine experienced some mechanical issues in August and December when it had availability of 87%. **Figure 9** also contains evidence that wind turbines can produce power above their recorded nameplates with peaks above the 900 kilowatt nameplate recorded in the months of December-March each year.

Figure 8.

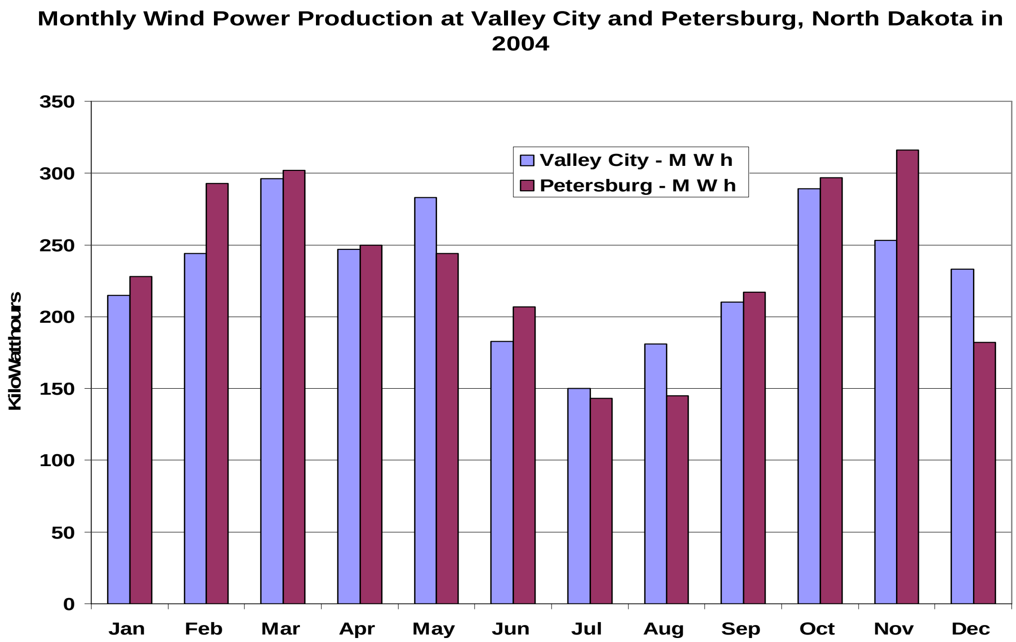


Figure 9.

2004 Monthly Statistics *Infinity* - Valley City, ND
900 kW Wind Turbine

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Power production - MWh	215	244	296	247	283	183	150	181	210	289	253	233	2784
Average wind speed - mph	16	17	19	17	18	15	13	14	16	19	18	17	
Capacity factor - %	32	39	44	38	42	27	22	27	32	43	39	35	
Peak output - kW	937	939	973	866	881	757	721	785	786	900	866	929	
Availability - %	91	98	99	99	99	99	99	93	100	100	90	99	

2004 Monthly Statistics *Infinity* - Petersburg, ND
900 kW Wind Turbine

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Power production - MWh	228	293	302	250	244	207	143	145	217	297	316	182	2824
Average wind speed - mph	16	19	20	17	18	16	13	14	16	19	20	18	
Capacity factor - %	34	47	45	39	36	31	21	22	33	44	49	27	
Peak output - kW	934	904	940	838	815	752	674	754	757	844	845	928	
Availability - %	95	99	99	99	99	97	97	87	100	100	100	87	

Analysis of Hourly Wind Production Data

Minnkota also offers hourly production data for its two wind turbines.[10] This body of data offers greater opportunity to understand the requirements to complement wind power, especially for the hours of the day when utilities need to be "on-peak" during the key months of June, July, August, and September. **Figures 10, 11, 12, and 13** are graphs that show the hour by hour production of power during On-Peak hours by Minnkota Electric's Petersburg, North Dakota wind turbine in the months of June-September of 2003, the key time periods when capacity payments are made for qualifying facilities that achieve 65% capacity during the hours 9:00 a.m. to 9:00 p.m., Monday through Friday, excluding holidays. The four graphs reveal the effect of lower wind velocities during that time of the year, particularly in July.

[10] Minnkota Power, Hourly Historical Output. Website: http://www2.minnkota.com/%7Elmbbs/infinityoutput.xls

Figure 10. June 2003 Hourly On-Peak Power Production from Wind at Petersburg, ND (Source: Minnkota Electric)

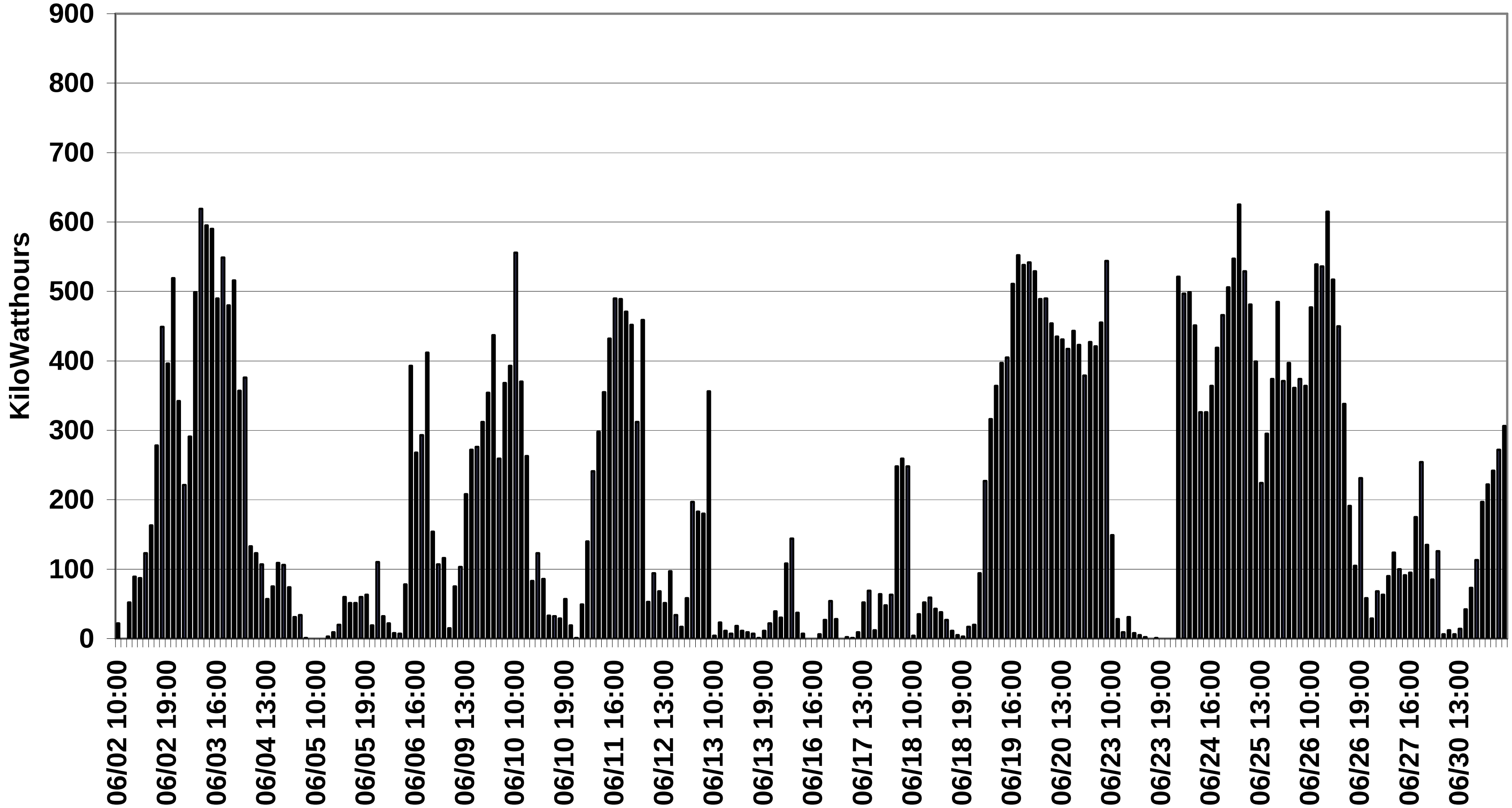


Figure 11. July 2003 Hourly On-Peak Power Production from Wind at Petersburg, ND (Source: Minnkota Electric)

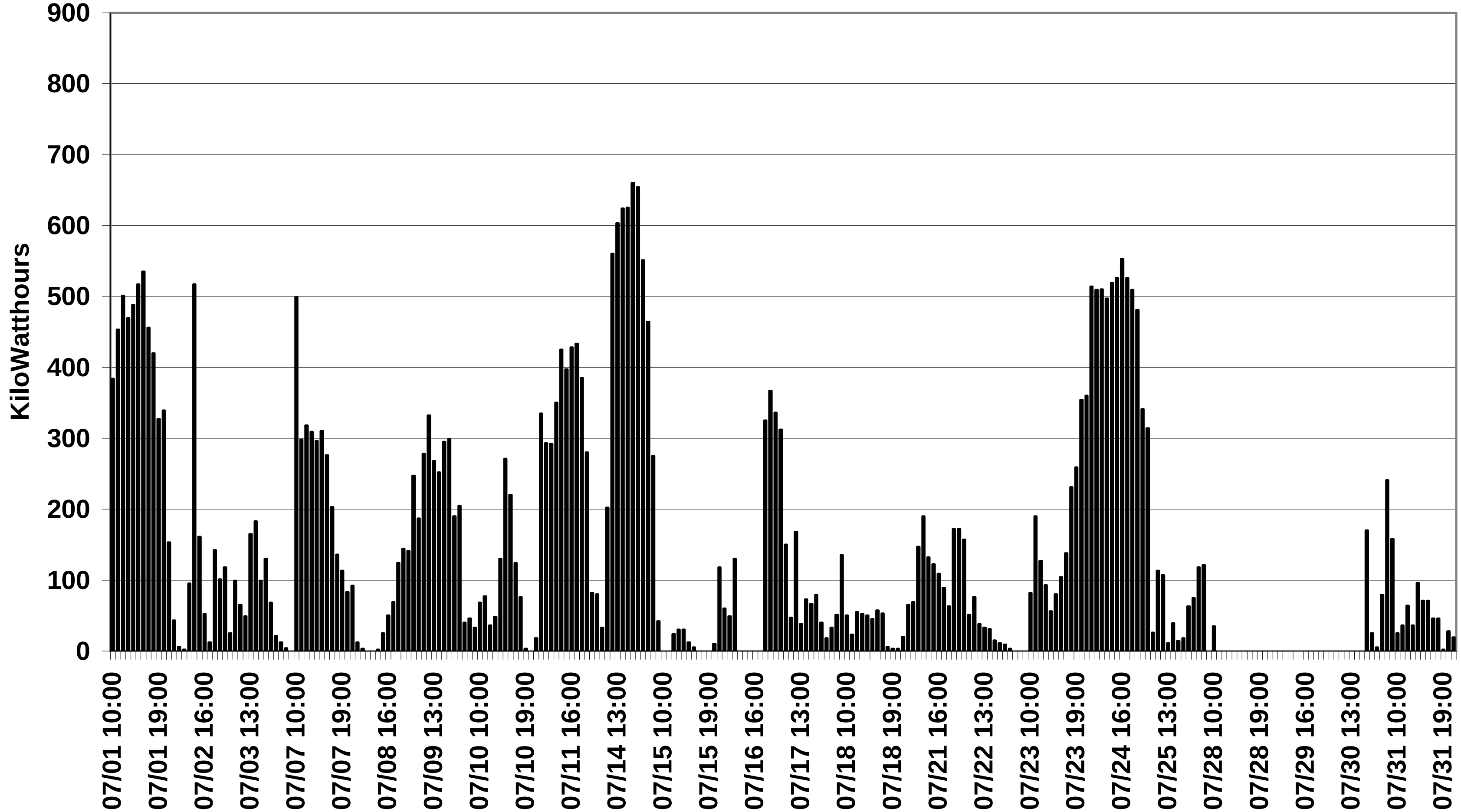


Figure 12. August 2003 Hourly On-Peak Power Production from Wind at Petersburg, ND (Source: Minnkota Electric)

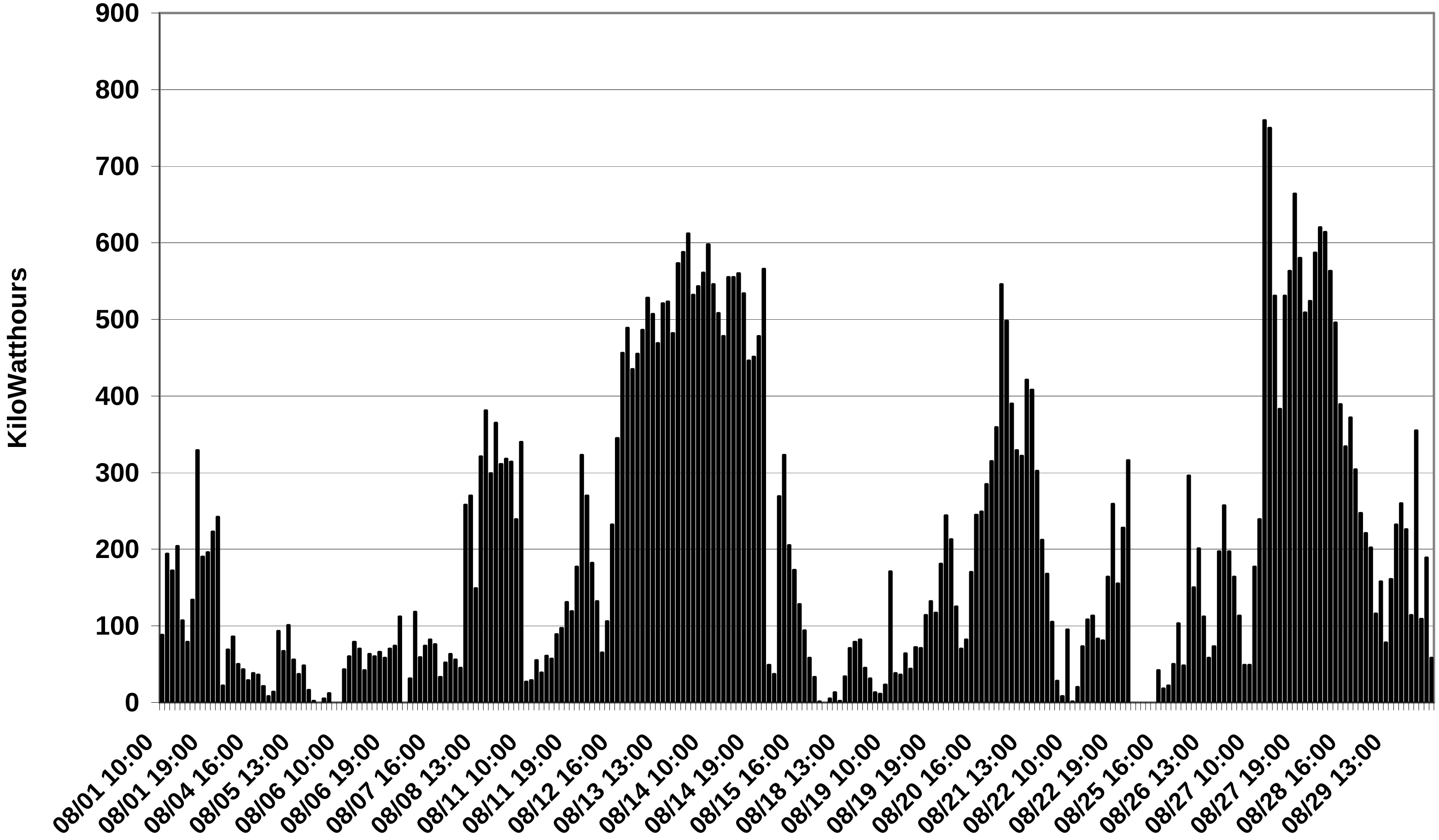
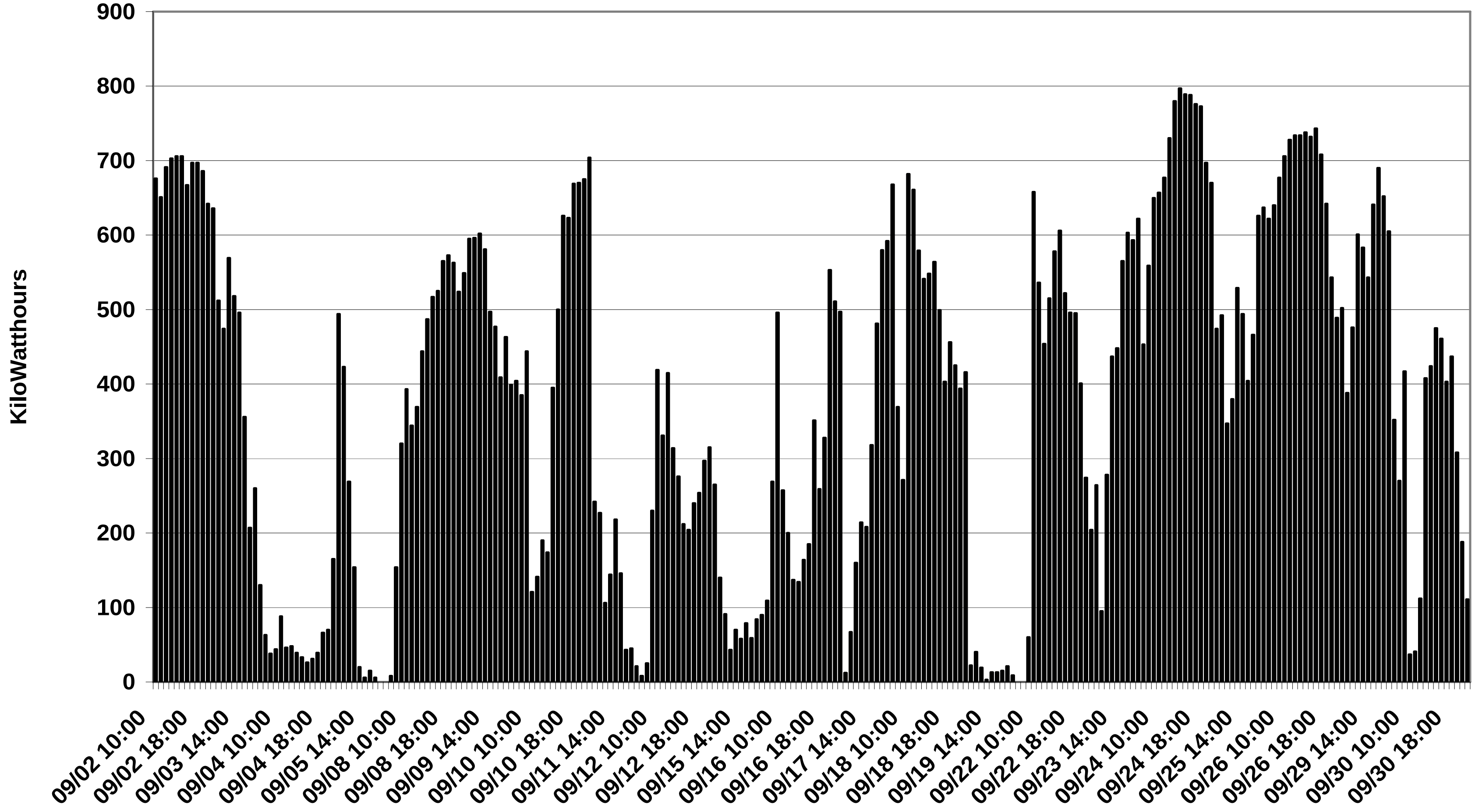


Figure 13. September 2003 Hourly On-Peak Power Production from Wind at Petersburg, ND (Source: Minnkota Electric)



Measurement of On-Peak Gaps

Once one gains an understanding of the pattern of hourly power production by the wind turbines over each of the key months June-September, it is important to look at the production of wind during the on-peak hours of 9:00 am through 9:00 pm Monday through Friday except during the key holidays of July 4 (or the Monday following it, if it falls on a weekend) and Labor Day (1st Monday in September). The historical hourly wind data was sorted to cut out the non-peak hours of each of the four key months. Then actual wind power production was subtracted from 65% of wind nameplate capacity to determine the "on-peak gaps" in power production from wind. **Figure 14** contains the number of hours that wind would need to be complemented by a genset at rated output based on the wind production at Valley City and Petersburg during 2003 and 2004 during the peak hours 9:00 a.m. to 9:00 p.m. during working days during the summer months.

Figure 14.

Hours of Genset Operation at Nameplate Needed to Reach Combined 65% Capacity with Wind Turbine for On-Peak Hours of June-Sept. at Valley City and Petersburg, ND

	June	July	Aug	Sept.	Totals per Site and Year
Valley City 2003	107.57	122.28	107.64	69.44	**406.93**
Valley City 2004	84.34	138.84	111.55	96.81	**431.54**
Petersburg 2003	106.8	129.11	106.4	57.28	**399.59**
Petersburg 2004	79.45	140.78	113.39	91.29	**424.91**
Mean Hours	**94.54**	**132.75**	**109.75**	**78.71**	**415.74**

What becomes clear is the number of hours that a diesel genset would have to run in each of the four key months during on-peak hours in order to achieve a combined capacity factor of 65% with the wind turbine. Looking at the years of 2003 and 2004 at the two locations, June, July, August, and September would have required the following number of genset hours of operation at its nameplate capacity: June---94.54, July---132.75, August---109.75, and September---78.71 . Mean total hours of genset operation for the two sites over the two years of the data would have been 416 hours. This figure will be important in analyzing the economics of using diesel gensets to complement wind turbines during the on-peak hours of June-September at Minnesota wind sites with similar capacity factors.

Capital Costs of Wind Turbines

Establishment of a wind turbine must be preceded by an adequate wind survey of a potential site**.** Towers are set up with anemometers in order to monitor the wind over a year's time. Wind velocity readings are often taken at 70 meters this height because at these heights wind turbines suffer less turbulence from trees, buildings, ground surface roughness, or local relief. When a site with suitable wind resource is identified, wind development easements are typically executed so that the contracting party can proceed to development if other considerations are satisfied. Chief among these is the location of the possible site for interconnection with the grid. There are typically capital costs for securing a service road to the tower and the area occupied by the tower supporting the turbine. Further capital costs include the installation of electrical cable to transmit the power produced by the turbine. When wind farms containing numerous wind turbines are established in an area, a control center is usually established that electronically monitors the production of power from many turbines. A shop area containing tools for turbine maintenance is generally part of the control center. The typical life of a wind turbine may vary based on the climate where established. However, increasing experience seems to indicate that 20 years of life is reasonable for many of the modern turbines being erected today. Some contacts have suggested that turbine blades or the generator, itself may be replaced by superior models after twenty years of operation.

Operating Costs of Wind Turbines

As mentioned previously, wind power requires large up-front investments. Because no fuel must be purchased operating expenses are typically quite small. However, wind turbines, like many machines have bearings and fittings that require routine greasing and inspection. In some situations, it is necessary to clean impacted insects from the turbine blades to maintain high efficiency. There are instances when damage can occur from ice, high winds, or lightning that may require substantial repairs by trained mechanics. Wind turbines occasionally suffer fires and various protection components may need to be replaced. Most wind turbines have instrumentation to report levels of production. Many wind turbines are sold with maintenance packages and insurance for damage from various problems that might render the turbine inoperable. Particularly important to lenders are insurance policies that protect against business interruptions. In some cases the international firms selling the wind turbines must gain an appreciation for the unique hazards of high winds, ice, and lightning in a particular locality. Electricity to run instrumentation on a wind turbine and annual lease payments for site of the wind turbine are additional operating expenses.

Discussion of Diesel Gensets
Gensets are engine-driven generators of various sizes, which are typically diesel powered in the case of larger units. The engine converts the chemical energy of a fuel into mechanical energy that spins coils of wire around magnets in order to produce electricity that is typically A.C. and at a particular kilowatt rating. Substantial losses in energy occur from the conversion of chemical energy in the fuel to mechanical energy at the shaft turning the generator to the conversion of electrical energy as it leaves the generator. Review of performance data on diesel gensets reveals they are capable of converting the lower heating value (LHV) of diesel fuel to work energy at a 41.27% rate. Then the conversion of mechanical energy delivered to the generator to electrical energy output is typically 93.90% efficient.[11] So from diesel fuel to electrical current, 38.75% of the energy is available after conversion, or 68.38 gallons of diesel fuel per Megawatt-hour in modern gensets. Presumably this loss in energy is acceptable because the chemical energy in the fuel is being changed to a more useful form—electrical current. Gensets are used widely to provide back-up and emergency electricity in many settings. In many cases gensets are restricted to providing electricity only for specific buildings, appliances, and equipment. In other instances electrical power from gensets may be permitted to flow beyond immediate locations and contribute to power available on the electrical transmission grid. For purposes of this study, we shall confine our analysis to a genset capable of replacing some or all of the power from an idle wind turbine rated at 1.65 MW. Further study may determine the opportunity of complementing the production of multiple wind turbines with large generators, whether diesel gensets or powered by natural gas or another fuel.

Like other diesel-powered equipment, gensets experience longer lives when given adequate time to warm up and cool down before and after operation. Gensets consume little fuel when idled for extended periods, producing no power. They are then available to quickly respond to load requests.

Capital Costs of Diesel Gensets
The diesel genset and switchgear considered of appropriate size to complement a 1.65 MW wind turbine would cost $350,000 , or $175.00 per kilowatt of standby capacity.[12] To protect the genset and its fuel storage tank from the elements and keep the system ready for quick starts, a building is assumed a necessary expenditure

Operating Costs of Diesel Gensets
Diesel gensets, like most diesel engines, require certain routine maintenance activities such as changes of motor oil, filters, coolants and servicing of fuel injectors. These are relatively minor, but important expenditures for an engine that may operate for long periods of time at constant loads. Many diesel gensets remain operational for decades with typical maintenance schedules. The chief operating expense is that of fuel. Estimates of fuel requirements per kilowatt-hour produced are considered relatively uniform for many gensets available today.

[11] Caterpillar, Inc. Gen Set Package Performance Data for Sales Model 3516BDITA, dated December 3, 2004.
[12] Paul Meyer, Ziegler Caterpillar, Shakopee, MN.

Assumptions

Electrical Revenue, Rules and Tariffs

The Minnesota Electric Rate Book –MPUC No. 2, contains a section entitled “Technical and Special Terms for Cogeneration and Small Power Production,” that identifies a number of rules and definitions needed to determine revenue for wind turbines complemented by generators using renewable fuels. Here are two key regulatory definitions:

Firm Power Firm power is energy delivered by a QF to the utility with at least 65% on peak capacity factor in the billing period. The capacity factor is based upon a QF’s maximum on-peak metered capacity delivered to the utility during the billing period.

On-Peak Period The on-peak period contains all hours between 9:00 am and 9:00 p.m. Monday through Friday, except the following

Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday.

In 2003, capacity payments of $.01 per kWh for Firm Power were offered for on-peak power during the key June-September period by Northern States Power Company (NSP) in Minnesota.[13] In 2005 the published rates per kilowatt hour and for capacity are $.0620 and $.0367, respectively. [14] It must be emphasized that this tariff represents an annual offering, so it would be difficult for a power producer to project earnings at this level for the life of the investment. No qualifying facility (QF) can hope to sell power and receive capacity payments from Xcel Energy (NSP’s successor organization) for more than a year at these rates. In fact, discussion with an Xcel employee[15] revealed that no QF’s were currently receiving such a package of payments.

[13] Northern States Power Company, Minnesota Electric Rate Book-MPUC No.2, Section 9, 5th Revised Sheet No. 3, filed 12/31/02 by Ken T. Larson., with an effective date of 1/01/03.
[14] Xcel Energy Tariff Document, Time of Day Purchase Service, Section No. 9, Rate Code A52 , 7th Revised Sheet No. 4, filed on January 3, 2005.
[15] John Chow, Xcel Energy, phone conversation, August 4, 2005.

Biodiesel Blend Levels in Cogeneration under PURPA
According to PURPA regulations, definitions for renewable energy include the following two standards:

1) Primary fuel (without cogeneration)[16] means a minimum of 75% of the total energy input in any calendar year if cogeneration is not used at the facility.
2) Primary fuel (with cogeneration)[17] means a minimum of 55% of the total energy input in any calendar year if cogeneration is used at the facility.

These standards suggest that electricity derived from biodiesel blends of 75% (B75) in a cogeneration setting shall be accepted as a Qualified Facility (QF). In the event that heat is captured and used by the QF, 55% biodiesel blends (B55) would qualify.

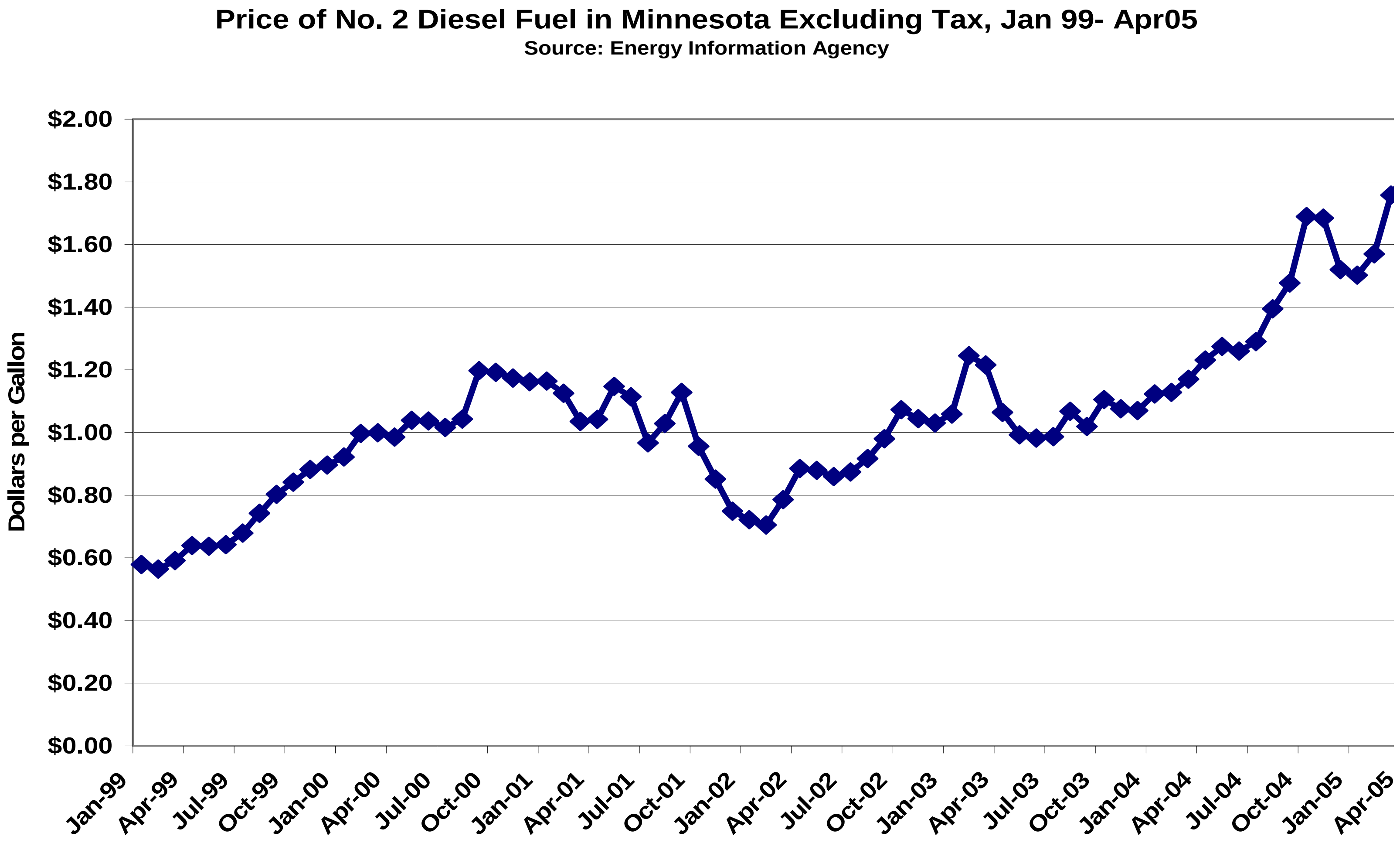
We assume typical operations of diesel gensets to complement wind turbines will be remote from other processing facilities and unable to utilize energy from cogeneration. Because B75 blends are assumed necessary to qualify under PURPA, B75 blends were studied in the analysis section of this paper.

Costs of Diesel and Biodiesel
Data from the Energy Information Agency were used to construct **Figure 15**, which shows Minnesota wholesale prices for No. 2 Diesel fuel for January 1999 through April 2005. This price is comparable to the price that would be paid for bulk delivery of diesel. As this paper is written, historically high prices for crude oil have pushed all petroleum products to record levels in nominal terms, with No. 2 Diesel priced at $1.80 per gallon. Prices for diesel fuel are determined by worldwide markets and are influenced by production levels of crude oil, refinery capacity, and seasonal demand for such uses as fuel oil for home heating. Within the U.S., diesel and petroleum are generally transported quite inexpensively by pipelines to regional distribution centers.

[16] Public Utilities Regulatory Policies Act, Code of Federal Regulations, 18CFR292.204 (b) (1) (i).

[17] Public Utilities Regulatory Policies Act, Code of Federal Regulations, 18CFR292.205 (a)(2)(i)(B).

Figure 15.



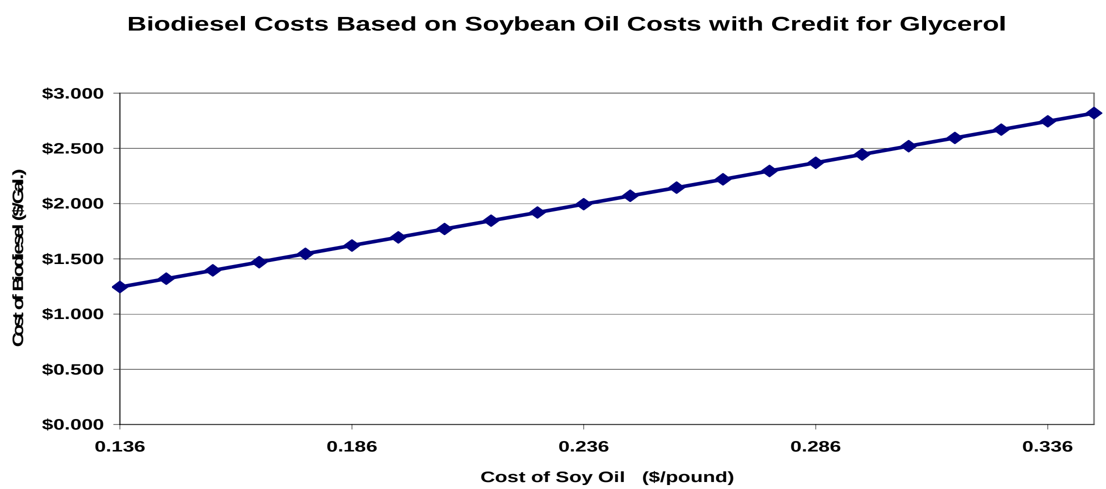
Price of No. 2 Diesel Fuel in Minnesota Excluding Tax, Jan 99- Apr05
Source: Energy Information Agency
Dollars per Gallon
$2.00
$1.80
$1.60
$1.40
$1.20
$1.00
$0.80
$0.60
$0.40
$0.20
$0.00
Jan-99
Apr-99
Jul-99
Oct-99
Jan-00
Apr-00
Jul-00
Oct-00
Jan-01
Apr-01
Jul-01
Oct-01
Jan-02
Apr-02
Jul-02
Oct-02
Jan-03
Apr-03
Jul-03
Oct-03
Jan-04
Apr-04
Jul-04
Oct-04
Jan-05
Apr-05

Costs to produce biodiesel depend largely upon the price of the oil feedstock used to make it, whether from virgin vegetable, recycled vegetable, or animal sources. However, the market clearing prices for biodiesel depend upon its value as a substitute for petro-diesel and its value as a fuel additive to improve lubricity in ultra-low-sulfur-diesel and reduce emissions including particulates. In Minnesota, a 2% mandated blend level of biodiesel will be effective in restoring lubricity of diesel fuel when EPA regulations require Ultra-Low Sulfur Diesel (ULSD) in 2006 in advance of new diesel engines appearing in 2007.

Firms choosing to produce biodiesel generally design and locate their facilities to utilize de-gummed soybean oil even though soybean oil is typically much more expensive than other sources of fats, particularly recycled yellow grease, which is often half the cost. This is evident with the establishment of production facilities at Brewster and Glenville, Minnesota in 2005 as well as a plant planned for Iowa Falls, Iowa in 2006. The behavior of the biodiesel firms demonstrates their preference for using soybean oil despite its higher price and their confidence that the Biodiesel Tax Credit of $1.00 per gallon of agricultural biodiesel will remain in force for some time. Lacking the Biodiesel Tax Credit, one would expect the production of biodiesel to predominate in close proximity to population centers with large supplies of waste grease or in locations near slaughter facilities with large supplies of tallow and lard.

A detailed study of biodiesel production costs by Haas, McAloon, Yee, and Foglia reported the cost of biodiesel at $2.00 per gallon using soybean oil priced at $.236 per pound and revealed that 88% of total estimated production costs are due to the cost of the oil feedstock.[18] Based on Hass et al. and their study, costs of biodiesel derived from soybean oil conform to **Figure 16.**

Figure 16.



(Source: Haas, et al., Bioresource Technology, Elsevier)

[18] Haas, Michael J., et al. "A Process Model to Estimate Biodiesel Production Costs," Bioresource Technology, accepted paper, pending publication.

Biodiesel production in the U.S. is small at 30 million gallons per year in 2005, but is currently experiencing rapid expansion in capacity. [19] The nations of the European Union produced over 450 million gallons in 2003 with heaviest reliance on the feedstock of rapeseed oil, derived from rapeseed grown on set-aside acres.[20]

Anthony Radich performed a detailed study of biodiesel for the Energy Information Agency and predicted the costs biodiesel made from soybean oil or yellow grease and with or without the proposed Biodiesel Tax Credit. Fate and circumstances made his projections of the cost of petro-diesel far lower than experienced in 2005. However, his projections for costs of biodiesel are sound and found in **Figure 17**. [21]

Figure 17.

Projected Production Costs for Diesel Fuel
by Feedstock, 2004-2013 (2002 Dollars per Gallon)

Marketing Year	Soybean Oil	Yellow Grease	Petroleum	Soybean Oil with Credit	Yellow Grease with Credit
2004/05	2.54	1.41	0.67	1.54	0.91
2005/06	2.49	1.39	0.78	1.49	0.89
2006/07	2.47	1.38	0.77	1.47	0.88
2007/08	2.44	1.37	0.78	1.44	0.87
2008/09	2.52	1.40	0.78	1.52	0.90
2009/10	2.57	1.42	0.75	1.57	0.92
2010/11	2.67	1.47	0.76	1.67	0.97
2011/12	2.73	1.51	0.76	1.73	1.01
2012/13	2.80	1.55	0.75	1.80	1.05
Means	**2.58**	**1.43**	**0.76**	1.58	0.93

Yellow grease is usually predicted to be 49% of the cost of soybean oil and soybean oil was predicted based on Energy Information Agency (EIA) models. The transportation bill passed by the U.S. Congress includes excise tax credits for biodiesel blending that can be claimed against Federal motor fuels excise taxes. If the biodiesel is made from virgin oil, the credit is $1.00 per gallon. If the biodiesel is made from non-virgin oil such as yellow grease, the credit is $.50 per gallon of biodiesel used in a blend. Alternatively, business tax income tax credits at the same rates are offered for virgin and non-virgin oil for users not using transportation fuels. The federal tax credits on biodiesel will be available through 2008.

[19] McCoy, M., 2005. "An Unlikely Impact," Chemical Engineering News 83 (8) p. 19
[20] European Biodiesel Board, 2004, "Biodiesel Production Statistics," website: http://www.ebb.eu.org/stats.php>.
[21] Radich, Anthony. Energy Information Agency. Website: http://tonto.eia.doe.gov/FTPROOT/environment/biodiesel.pdf - Aug. 2, 2005

Analysis

Calculations using the workbook were carried out by setting assumptions on the "Wind" and "Genset" spreadsheets with examples following in **Figures 18** and **19.** Discount rates, percentages financed, and interest rates established on the "Wind" spreadsheet are also applied in the "Genset" spreadsheet. The two linked spreadsheets for the two methods of producing power can be altered to conform to various operating expenses and capital costs.

The "Wind" spreadsheet in **Figure 18** establishes the power production by a particular model of wind turbine operating on a site with a specified capacity factor. Under "Assumptions," cells shaded yellow in the spreadsheet allow one to specify wind turbine capacity, capacity factor, and price for purchased power, discount factor for the investment and the salvage value or even additional removal expense at the end of the assumed twenty year life. Additional assumptions should be established for the percent equity and debt as well as the rate of interest charged on debt. Amounts for up-front capital are entered under "Capital Expenditures" and include site investigation costs, legal fees covering sites, easements, and power purchase agreements. Working capital is also included as well as the costs of the very tangible wind turbine and feeder lines.

Under the Revenues or Credits section of the spreadsheet, Revenues for the sale of electricity are listed in each of the twenty years in Row 23. The potential credits available from the federal Production Tax Credit (PTC), which is currently 1.9 cents per kilowatt-hour produced are listed for the first ten years in Row 24. The PTC would have no value if the owner or owners have insufficient tax liability to use the credit on passive income. Some Minnesota wind turbines have received the Minnesota Small Producer Wind Incentive payment for each of the first ten years of operation at the rate of 1.5 cents per kilowatt hour produced. Eligibility is limited to units in the queue and awaiting construction of 2.0 MW or less, with the incentive now reduced to 1.0 cents per kilowatt-hour. It is unknown if this attractive incentive payment will be available beyond 2006. Although no value is listed, another potential source of income for the owners of a wind turbine are the sale of "green tags," which may have value if sold to businesses or utilities that need them in particular states. In many instances green tags are transferred to the utility buying the power in the course of negotiating the power purchase agreement (PPA). In some cases rural businesses and cooperatives can receive U.S. Department of Agriculture grants up to 25% of non-land capital costs in advance of production starting, also noted with a yellow-shaded cell **C27.** This can be a substantial benefit when awarded, but only 10-15% of wind turbines built in recent years have received these grants.[22]

[22] Noty, Lisa. U.S.D.A. Rural Development. Personal Interview April 13, 2006.

Wind operating expenses are listed for each year of the estimated twenty years of operation and include the annual amounts for land lease, service and warranty packages, electricity, insurance, accounting, and local real estate taxes based on production of electricity. These amounts are listed in rows 31 -36 for years 1-20. Debt service consisting of equal amortized principal and interest payments are recorded for the first ten years in **Row 37**.

After Net Operating Expenses are calculated for each of the twenty years in the projected life of the wind turbine, the Net Cash Flow for each year is calculated and recorded in **Row 40**. **Row 41** records the discounted cash flow of each year using the 9.0% rate established in cell C8, while **Row 42** records the accumulated discounted cash flow with each passing year of the wind turbine project. In year 20, $161,300 is assumed to be received as a salvage value of the wind turbine. The Net Present Value of the Project is shown in cells **C44** and also **M4**. Cell **M5** contains the average cost per kilowatt-hour produced over the 20 years. Cell **M6** contains the internal rate of return that was achieved by the cash flows actually received and is 13.30% in **Figure 18** with the wind site having a 35% capacity factor.

The "Genset" worksheet (**Figure 19**) establishes the capital cost to purchase and site a typical diesel genset. The format of this spreadsheet is very similar to the one established for the wind turbine. However, the genset worksheet has some other cells to record assumptions for fuel cost, hours of operation, and the blend percentage of biodiesel utilized. Cell **C5** contains the annual percentage of time that the genset would run and results in the annual hours of operation recorded in cell **C6**. Cell **C7** records the annual production based on the hours of operation and the genset's rated capacity (**C4**). Cells **H5-H7** establish the amount of interest and principal to be repaid. Cells **H9** and **H10** establish the effective prices for diesel and biodiesel, respectively. Cell **H11** establishes the biodiesel blend level to be utilized and become a Qualified Facility (QF).

There are budgeted capital costs for the genset, a building to house it, the tanks for fuel, interconnection equipment, and transmission lines in cells **C15-C19**.[23] Capital amounts required for site negotiation and easement legal fees were based in part on estimates made for wind turbines. Of note is the salvage value established for the genset in cell **C11.**

In terms of revenue and credits, the diesel genset is assumed to receive $.0620 during June through September for each kWh produced as well as $.0367 as a capacity payment for each of the On-Peak Hours that the genset is available to operate in the June-September period. These figures are recorded in **C8** and **C9**, respectively. The assumption is made that the genset is operated only during the summer months and that all the capacity payments should be allocated to the genset even though the genset is responsible for only part of the power output. This is based on the published documents filed by Northern States Power (NSP) with the Minnesota Public Utilities Commission.[24]

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[23] Interview: Paul Meyer, Ziegler Caterpillar.
[24] Xcel Energy Tariff Document, Time of Day Purchase Service, Section No. 9, Rate Code A52 , 7th Revised Sheet No. 4, filed on January 3, 2005.

The revenue from the sale of “green tags” which are sometimes sold at $.01 per kWh is ignored in this analysis because a utility such as NSP may acquire these in the course of granting a power purchase agreement (PPA). The genset spreadsheet (**Figure 19**) may use cell **C29** to portray the situation of rural organizations such as coops and limited liability corporations eligible and fortunate to receive USDA Economic Development grants, which have the effect of reducing the amount of initial capital required.

Annual fees for a maintenance plan for the genset are recorded in **Row 33**. Debt service is shown in the first ten years based on equal amortized annual payments in **Row 34**. Insurance premiums of $2,000 per year were budgeted for each of the twenty years of the genset’s life in **Row 35**. Fuel cost (**Row 36**) reflects the blend level selected, the prices of the petro-diesel and biodiesel, as well as the requirement of 5.5% more biodiesel to satisfy the same amount of power output by the genset.[25] [26] Property taxes of $675 per year were estimated and recorded in **Row 37** for the building and the small lot it would occupy. After "Revenues and Credits" are reduced by "Operating Expenses and Capital Expenditures," "Net Cash" flows are determined for each of the twenty years of the genset’s life. Then the net cash flows are discounted by the established rate 9.0% (**C10**).

The Net Present Value for the genset project is recorded in cells **C43** and **M4**. Among the other conclusions are those for the “Genset Alone” in column **M**, with average cost per kWh in **M5** and the internal rate of return for the genset in **M6**. **M8** has the annual production in kilowatt-hours of the genset with the gallons of two types of diesel and in total in cells **M9-M11**.

Conclusions in **Column N** offer a review of the conclusions from the wind spreadsheet in cells **N5, N6, N7**, and **N8**. In **Column O** we have conclusions for the hybrid operation of the wind turbine and the diesel genset. **Cell O4** contains the overall NPV of the combined project, while **O5** contains the average cost per kilowatt-hour for the combination of wind turbine and genset operation. **Cell O6** contains the combined internal rate of return for both machines producing electrical power, while **O8** contains the amount of electricity produced by the pair.

[25] Determination of fuel requirement for various biodiesel blends was based on the following data: diesel fuel has a LHV of 129,050 BTU per gallon; biodiesel has a LHV of 118,170 BTU per gallon. Biodiesel has a higher density per unit of volume with 7.328 pounds per gallon versus 7.079 pounds per gallon in diesel. Based on these two relationships, it is reasonable to calculate that 5.50% greater volume of biodiesel will be needed to produce the same amount of power as petro-diesel.

[26] “2004 Biodiesel Handling and Use Guidelines.” U.S. Department of Energy, Energy Efficiency and Renewable Energy Division. Website: http: //www.osti.gov/bridge.

Figure 18. **Wind Turbine Production Economics**

by Douglas G. Tiffany, Dept. of Applied Econ., University of Minnesota
7/14/2006

Assumptions:

Wind Turbine Capacity	1.650	MW	Percent Equity	40.00%	
Capacity Factor of Wind Site	35	%	Percent Debt	60.00%	
Annual Production	5,058,900	KWH	Interest Rate	7.00%	
Price for Purchased Power	$0.0330	per KWH			
Discount Factor (%)	9.00%				
Salvage Value(+)/Removal Cost (-)	$161,300				

Conclusions:

NPV of 20 Yr. Project	250,543
Average Cost per KWH	$0.03652
IRR for Project	13.30%

	1,0	Initial	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Capital Expenditures																						
Site Investigation		20,000																				
Legal-- for Site		2,000																				
Legal-- Power Purchase		5,000																				
Interconnection Fees		5,000																				
Tower, Turbine & Installation		1,613,000																				
Transmission Feeder Lines		2,000						50														
Working Capital		8,000																				
Salvage Value/Removal Expense																						-161,300
Total Capital Expenditures		1,655,000																				-161,300
Revenue or Credits																						
Power Purchased	1	0	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944
Production Tax Credit (Federal)	1	0	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119										
MN Sm Producer Paymt @1.5	1	0																				
Sale of Green Tags @ $.01/ kWh	0																					
USDA Rural Develop. Grant	1	0																				
Total Revenue or Credits		0	263,063	263,063	263,063	263,063	263,063	263,063	263,063	263,063	263,063	263,063	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944
Operating Expenses																						
Land Lease			4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Service and Warranty			12,500	12,500	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900
Electricity			1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Insurance			10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Accounting			1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Property Taxes (production)			607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607
Debt Service (P+ I)			141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381										
Total Operating Expenses		0	170,488	170,488	181,888	181,888	181,888	181,888	181,888	181,888	181,888	181,888	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507
Net Cash Flow		-662,000	92,575	92,575	81,175	81,175	81,175	81,175	81,175	81,175	81,175	81,175	126,437	126,437	126,437	126,437	126,437	126,437	126,437	126,437	126,437	287,737
Disc. Cash Flow of Year		-662,000	84,931	77,918	62,682	57,506	52,758	48,402	44,405	40,739	37,375	34,289	48,998	44,953	41,241	37,836	34,712	31,846	29,216	26,804	24,591	51,341
Cumulative Disc. Cash Flows			84,931	162,849	225,531	283,038	335,796	384,198	428,603	469,342	506,717	541,006	590,005	634,957	676,198	714,034	748,746	780,591	809,807	836,611	861,202	912,543
		Initial	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Net Present Value of Project		250,543																				

Figure 19. **Diesel Genset Production Economics**

by Douglas G. Tiffany, Dept. of Applied Economics, University of Minnesota
7/14/2006

Assumptions:

Diesel Genset Capacity	1.650	MW				
Capacity Factor for Genset	5.00	%	Percent Equity		40.00%	
Hours of Annual Operation	438.0	Hours	Percent Debt		60.00%	
Annual Production	722,700	KWH	Interest Rate		7.00%	
Price for Purchased Power	$0.0620	per KWH				
Price for Power Capacity	$0.0367	per KWH	Price of Diesel		$1.80	
Discount Factor	9.00%		Price of Biodiesel		$1.80	
Salvage Value(+)/Removal Cost (-)	$45,000		Blend	B	75	

Conclusions:

		Genset Alone	Wind Alone	Wind & Genset
NPV of 20 Yr. Project		-161,942	250,543	88,601
Average Cost per KWH		$0.19948	$0.03652	$0.05689
IRR for Project		1.57%	13.30%	10.12%
Annual Production	(kWh)	722,700	5,058,900	5,781,600
Petro-Diesel Gallons		12,827		
Biodiesel Gallons (B100)		38,481		
Total Gallons of Fuel		51,308		

	1,0	Initial	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Capital Expenditures																						
Interconnection Fees		5,000																				
Site & Service Road Acquisition		5,000																				
Tanks and Building		100,000																				
Diesel Genset with swithgear		350,000																				
Transmission Feeder Lines		25,000																				
Salvage Value(+)/Removal Cost(-)																						-45,000
Total Capital Expenditures		485,000																				-45,000
Revenue or Credits																						
Power Purchased	1	0	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807	44,807
Power Capacity Payment	1	0	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401
Production Tax Credit (Federal)	0	0																				
Small Wind Producer Payment (MN	0	0																				
Sale of Green-Tags @.01/kWh	1	0																				
USDA Rural Develop. Grant	1	0																				
Total Revenue or Credits		0	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209	133,209
Operating Expenses																						
Maintenance Plan		0	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095
Debt Service (P+I)			41,432	41,432	41,432	41,432	41,432	41,432	41,432	41,432	41,432	41,432										
Insurance		0	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Fuel Cost		0	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354	92,354
Property Taxes			675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Total Operating Expenses		0	142,881	142,881	142,881	142,881	142,881	142,881	142,881	142,881	142,881	142,881	101,449	101,449	101,449	101,449	101,449	101,449	101,449	101,449	101,449	101,449
Net Cash Flow		-194,000	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	31,760	31,760	31,760	31,760	31,760	31,760	31,760	31,760	31,760	76,760
Disc. Cash Flow of Year		-194,000	-8,873	-8,140	-7,468	-6,852	-6,286	-5,767	-5,291	-4,854	-4,453	-4,085	12,308	11,292	10,359	9,504	8,719	7,999	7,339	6,733	6,177	13,696
		Initial	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Net Present Value of Project		-161,942																				
Net Cash Flow Genset		-194,000	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	-9,672	31,760	31,760	31,760	31,760	31,760	31,760	31,760	31,760	31,760	76,760
Net Cash Flow Wind		-662,000	92,575	92,575	81,175	81,175	81,175	81,175	81,175	81,175	81,175	81,175	126,437	126,437	126,437	126,437	126,437	126,437	126,437	126,437	126,437	287,737
Combined Net Cash Flow		-856,000	82,903	82,903	71,503	71,503	71,503	71,503	71,503	71,503	71,503	71,503	158,197	158,197	158,197	158,197	158,197	158,197	158,197	158,197	158,197	364,497

Results of Analysis

Production Economics of Wind Turbines Alone

The first stage of analysis was to use the spreadsheet model to analyze the economic performance of wind turbines alone. In this regard, the effects of various capacity factors were determined on the production and project financial performance, as seen in **Figure 20**. As the capacity factors go up along with the kilowatt-hours produced per year, the costs per kilowatt-hour go down. When capacity factor goes from 25% to 50%, the cost per kilowatt-hour is essentially cut in half. At higher capacity factors net present values for wind turbine projects rise as do their internal rates of return. At capacity factors of 25% and 30% the NPV's are negative, meaning that it would be unwise to develop such a project when considering a 9.0% discount rate along with the other assumptions established. When the capacity factor rises to 35%, the NPV is positive by $250,543 and the IRR is 13.30%. As the capacity factor moves from 35% to 40%, the project's financial performance increases substantially with IRR rising from 13.30% to 18.70%. Projects with capacity factors of 45% are rare or unreported, but improved technology may make them possible near term. The effect of a $300,000 grant on improved internal rates of return can be seen for the respective capacity factors to the right of the Base Case, which is also assumed to lack the Minnesota Incentive Payment.

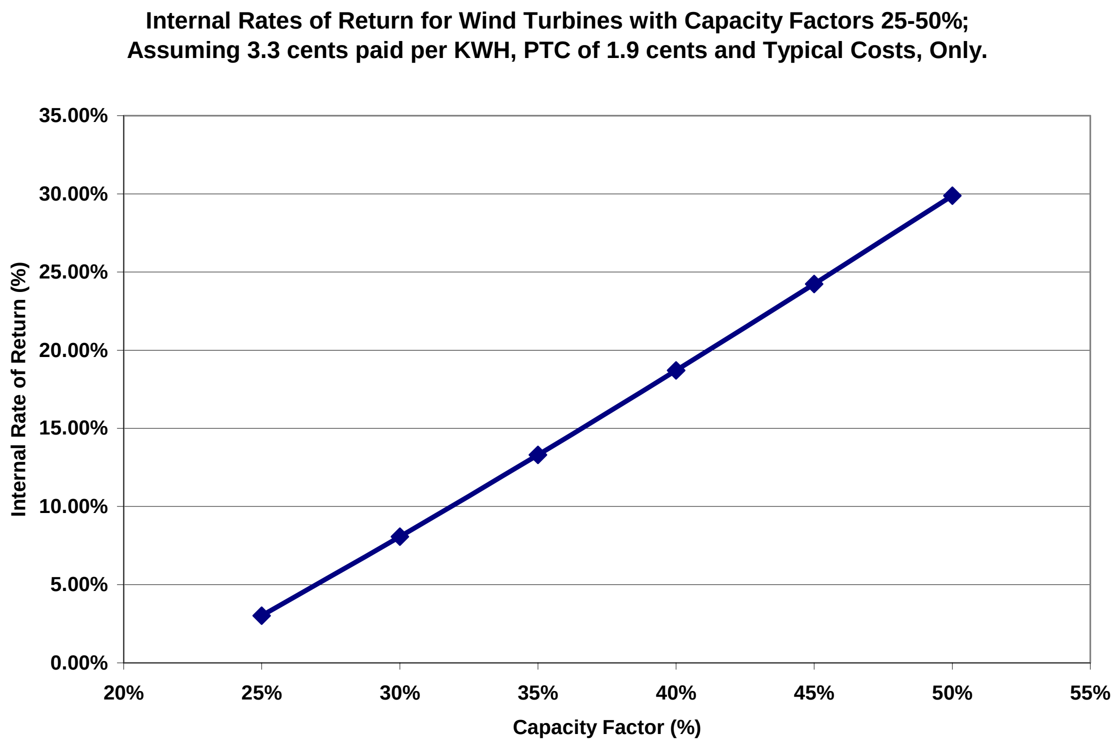
Figure 20.

Financial Performance of 1.65 MW Wind Turbine with Capacity Factors from 25-50%, Without Minnesota Incentive Payment

			Base Case		With $300,000 Grant	
Capacity Factor	Production(kWh)	Cost per kWh	NPV @ 9% Rate	IRR	NPV @ 9% Rate	IRR
25%	3,613,500	$ 0.05108	$ (359,535)	3.03%	$ (59,535)	7.54%
30%	4,336,200	$ 0.04258	$ (54,496)	8.08%	$ 245,504	15.51%
35%	5,058,900	$ 0.03652	$ 250,543	13.30%	$ 550,543	24.64%
40%	5,781,600	$ 0.03197	$ 555,582	18.70%	$ 855,582	34.57%
45%	6,504,300	$ 0.02843	$ 860,620	24.21%	$ 1,160,620	44.89%
50%	7,227,000	$ 0.02560	$ 1,165,659	28.88%	$ 1,465,659	55.35%

Figure 21 graphically displays the relationship between capacity factor and internal rates of return for the wind turbines with the assumptions established. The relationship is linear because we are using capacity factor. Qualification for state incentive payments or U.S.D.A. grants can improve internal rates of returns substantially.

Figure 21.



Production Economics of Diesel Gensets Alone with Biodiesel Credit
The "Genset" spreadsheet was used to determine some of the same financial performance measures that were computed with the wind turbine. In the case of the diesel genset, it was necessary to specify that the biodiesel blend is B75, which is the accepted blend for renewable definitions. In addition, biodiesel and petro-diesel were each considered to be priced at $1.80. This is in keeping with the pricing for biodiesel that will result due to the Biodiesel Tax Credit. **Figure 22** contains figures that allow one to see how the financial performance of the project changes as more and more hours of genset usage occur in a year's time.

Figure 23 graphically shows how IRR drops with increasing annual hours of usage, while **Figure 24** graphically shows the changes in cost per kilowatt hour produced by the diesel genset using B75 and both fuels priced at $1.80 per gallon. As the hours of annual operation go up, the cost per kWh goes up. **Figures 22, 23 and 24** will all be different if the assumptions for price of diesel fuel and biodiesel are changed. It is reasonable to calculate those changes that would occur if higher prices for biodiesel should occur after 2008 if the Biodiesel Tax Credit ends. Instead of presenting this analysis for various biodiesel price levels in the case of a diesel genset operating alone, that analysis will be presented following the case of a wind turbine complemented by a biodiesel powered genset.

Figure 22.

Cost per KiloWatthour of Electricity Produced by Diesel Genset Using B75 and Operating Various Hours per Year Using Petro-Diesel @$1.80 and Biodiesel @$1.80

Capacity %	Hours	KWH Produced	Cost/KWH	NPV
1	87.6	144,540	$ 0.48624	$ (659,960)
2	175.2	289,080	$ 0.30702	$ (785,029)
3	262.8	433,620	$ 0.24727	$ (910,098)
4	350.4	578,160	$ 0.21740	$ (1,035,168)
5	438.0	722,700	$ 0.19948	$ (1,160,237)
10	876.0	1,445,400	$ 0.16364	$ (1,785,584)
20	1752.0	2,890,800	$ 0.14571	$ (3,036,279)
30	2628.0	4,336,200	$ 0.13974	$ (4,286,973)
40	3504.0	5,781,600	$ 0.13675	$ (5,537,667)
50	4380.0	7,227,000	$ 0.13496	$ (6,788,361)
60	5256.0	8,672,400	$ 0.13338	$ (8,039,055)
70	6132.0	10,117,800	$ 0.13291	$ (9,289,749)
80	7008.0	11,563,200	$ 0.13227	$ (10,540,444)
90	7884.0	13,008,600	$ 0.13177	$ (11,791,138)
100	8760.0	14,454,000	$ 0.13137	$ (13,041,832)

Figure 23.

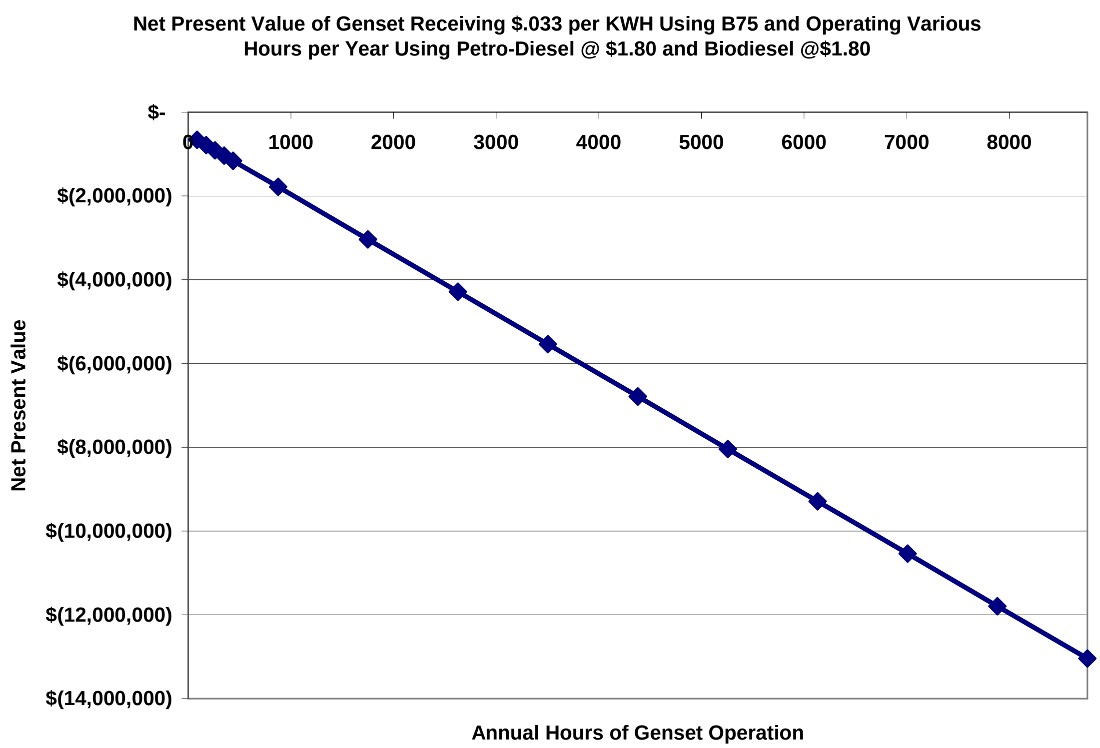
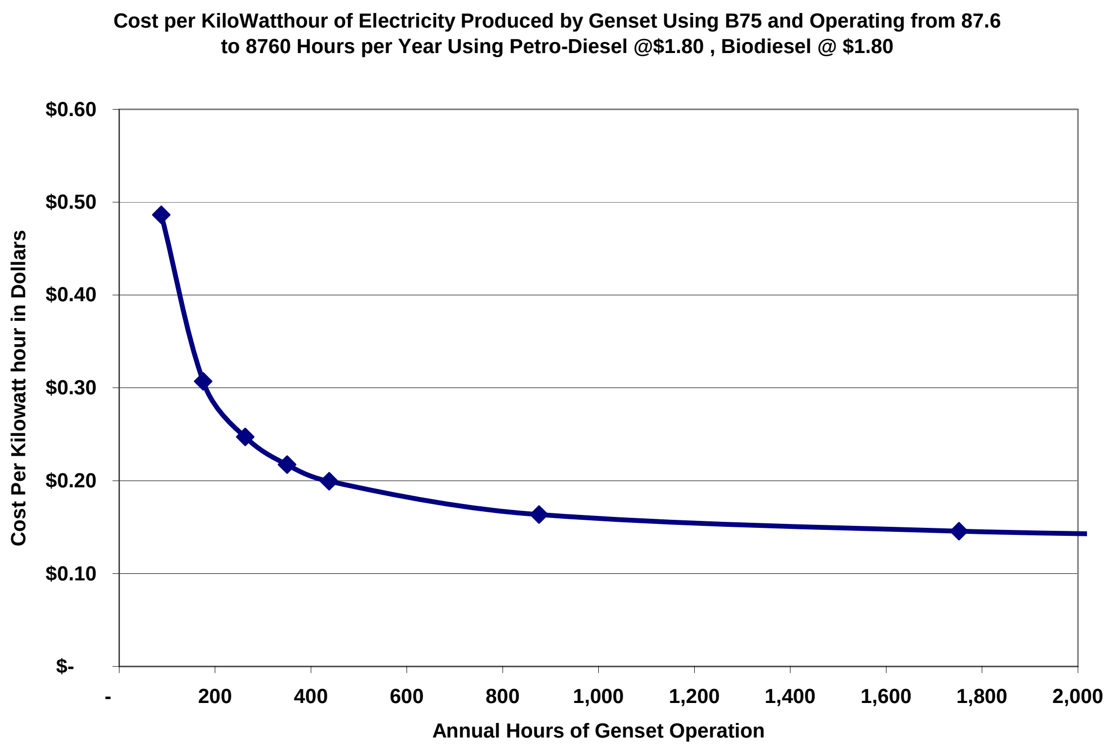


Figure 24.



Production Economics of Hybrid System with Biodiesel Tax Credit

The next stage in the analysis is to combine the operation of a wind turbine with a diesel genset and determine the financial effects of various factors such as capacity factor of wind site, number of hours or capacity required of the genset to reach “firm” power level of 65% during the key on-peak periods June-September, and the costs of diesel and biodiesel used in a B75 blend. The first set of analyses will conform to the current status with price of biodiesel equal to the price of petro-diesel through the use of the Biodiesel Tax Credit.

Figure 25 is a table that contains financial performance of running a biodiesel genset to complement a wind site with a 30% capacity factor using a B75 fuel blend with biodiesel and petro-diesel each costing $1.80 per gallon. According to previous analysis using the model developed, a wind turbine on a site with 30% capacity has a NPV of -$54,496 with standard operating assumptions as shown in **Figure 20**. The 2005 rates for purchased power and capacity offer returns greater than 9.0% only if the genset is operated 219.6 hours or less per year. The presence and usage of a diesel genset result in higher internal rates of returns for the wind turbine and genset the less the combination is used as long as the threshold for “firm” power and the payments for capacity can be reached. It is doubtful that a 30% capacity factor site can reach that threshold even with a genset running just 219.6 hours per year, as opposed to the 416 hours determined in **Figure 14**.

Figure 25.

Financial Performance of Wind Turbine on 30% Capacity Site Complemented by Genset @ B75 with Diesel/ Biodiesel Prices ($1.80/$1.80) for Various Amounts of Genset Operation

%	Hours	Diesel Price	Biodiesel Price	NPV	Cost/KWH	IRR	KWH Produced
1	87.6	1.80	1.80	$ 130,785	$ 0.05690	10.60%	4,480,740
2	175.2	1.80	1.80	$ 43,979	$ 0.05911	9.54%	4,625,280
2.51	219.6	1.80	1.80	$ -	$ 0.06018	9.00%	4,698,510

When considering the more typical wind capacity factor levels of 35%, the addition of the genset can result in positive NPV's for the wind turbine-genset package under the assumptions of existence of the Biodiesel Tax Credit if operating hours for the genset are kept below 527.4 hours per year. This level of genset usage should be attainable. **Figure 26** contains the financial performance of a 35% wind capacity factor site and various hours of operation of the diesel genset to achieve 65% firm power that would be needed for a "qualifying facility." This example most closely conforms to the two wind sites in Petersburg and Valley City, North Dakota with the annual capacity factors near 35%.

Figure 26.

Overall Financial Performance of Wind Turbine on 35% Capacity Site Complemented by Genset @ B75 with Diesel/ Biodiesel Prices ($1.80/$1.80) for Various Levels of Genset Operation

%	Hours	Diesel Price	Biodiesel Price	NPV	Cost/KWH	IRR	KWH Produced
1	87.6	$1.80	$1.80	$ 435,824	$ 0.04901	14.43%	5,203,440
2	175.2	$1.80	$1.80	$ 349,018	$ 0.05114	13.36%	5,347,980
3	262.8	$1.80	$1.80	$ 262,212	$ 0.05316	12.28%	5,492,520
4	350.4	$1.80	$1.80	$ 175,407	$ 0.05507	11.20%	5,637,060
5	438.0	$1.80	$1.80	$ 88,601	$ 0.05689	10.12%	5,781,600
6	525.6	$1.80	$1.80	$ 1,795	$ 0.05862	9.02%	5,926,140
6.02	527.4	$1.80	$1.80	$ -	$ 0.05865	9.00%	5,929,130

It is significant that at 527.4 hours of genset operation the NPV of the combined project is choked down to zero, or a 9.00% IRR. Recall that our estimate of the necessary number of hours needed during the key months during the prime hours of the two North Dakota wind turbines was 416 hours. Up to 175.2 hours of annual hours of annual genset operation, the investment and operation of that piece of equipment result in a higher overall IRR than the wind turbine alone. **For wind turbines of 35% capacity factor and better, the use of biodiesel-powered gensets would be financially prudent as long as the Biodiesel Tax Credit stays in effect to keep biodiesel equal in price to petro-diesel.** Above 175.2 hours of genset operation, the operational costs detract more from the overall project's NPV. Our analysis of the production of the two Minnkota turbines indicates that it should be quite easy to meet standards for firm power and capture the energy and capacity payments.

Higher capacity wind sites are better financial propositions for the use of the diesel genset because their project economics are so much better before the genset is added. Like the 35% capacity factor site, it is always more favorable to run the genset as little as needed to achieve the 65% firm definition. **Figures 27** and **28** show the favorable financial performance of adding biodiesel-fuelled gensets at 40% and 45% capacity wind sites, respectively--- as long as the Biodiesel Tax Credit keeps biodiesel price, essentially equal to the price of petro-diesel. The higher capacity sites can tolerate greater use of the diesel genset and still attain IRR's greater than 9.00%.

Figure 27.

Financial Performance of Wind Turbine on 40% Capacity Site Complemented by Genset with Diesel/ Biodiesel Prices ($1.80/$1.80) for Various Amounts of Genset Operation

%	Hours	Diesel Price	Biodiesel Price	NPV	Cost/KWH	IRR	KWH Produced
1	87.6	$1.80	$1.80	$ 740,862	$0.04350	18.41%	5,926,140
2	175.2	$1.80	$1.80	$ 654,057	$0.04507	17.32%	6,070,680
3	262.8	$1.80	$1.80	$ 567,251	$0.04699	16.23%	6,215,220
4	350.4	$1.80	$1.80	$ 480,446	$0.04883	15.14%	6,359,760
5	438.0	$1.80	$1.80	$ 393,640	$0.05058	14.04%	6,504,300
6	525.6	$1.80	$1.80	$ 306,834	$0.05226	12.94%	6,648,840
7	613.2	$1.80	$1.80	$ 220,029	$0.05387	11.84%	6,793,380
8	700.8	$1.80	$1.80	$ 133,223	$0.05541	10.72%	6,937,920
9	788.4	$1.80	$1.80	$ 46,417	$0.05688	9.60%	7,082,460
9.53	835.2	$1.80	$1.80	$ -	$0.05765	9.00%	7,159,749

Figure 28.

Financial Performance of Wind Turbine on 45% Capacity Site Complemented by Genset with Diesel/ Biodiesel Prices ($1.80/$1.80) for Various Amounts of Genset Operation

%	Hours	Diesel Price	Biodiesel Price	NPV	Cost/KWH	IRR	KWH Produced
1	87.6	$1.80	$1.80	$ 1,045,901	$ 0.03838	22.51%	6,648,840
2	175.2	$1.80	$1.80	$ 959,096	$ 0.04028	21.41%	6,793,380
3	262.8	$1.80	$1.80	$ 872,290	$ 0.04210	20.31%	6,937,920
4	350.4	$1.80	$1.80	$ 785,484	$ 0.04386	19.20%	7,082,460
5	438.0	$1.80	$1.80	$ 698,679	$ 0.04553	18.10%	7,227,000
6	525.6	$1.80	$1.80	$ 611,873	$ 0.04715	16.99%	7,371,540
7	613.2	$1.80	$1.80	$ 525,067	$ 0.04870	15.87%	7,516,080
8	700.8	$1.80	$1.80	$ 438,262	$ 0.05019	14.76%	7,660,620
9	788.4	$1.80	$1.80	$ 351,456	$ 0.05163	13.63%	7,805,160
10	876.0	$1.80	$1.80	$ 264,650	$ 0.05301	12.50%	7,949,700
11	963.6	$1.80	$1.80	$ 177,845	$ 0.05435	11.37%	8,094,240
12	1051.2	$1.80	$1.80	$ 91,039	$ 0.05564	10.22%	8,238,780
13	1138.8	$1.80	$1.80	$ 4,233	$ 0.05688	9.06%	8,383,320
13.05	1143.1	$1.80	$1.80	$ -	$ 0.05694	9.00%	8,390,369

Production Economics of Hybrid System without Biodiesel Tax Credit

The loss of the Biodiesel Tax Credit after 2008 would increase the operating costs of the diesel gensets and would reduce the number of hours that a genset could be operated and still contribute financially to the overall project of a wind turbine and a genset. The cost for biodiesel without the credit was assumed to be approximately $.80 more than the price of petro-diesel. This is based on the assumption that the feedstocks used for U.S. biodiesel production may eventually reach a weighting of 40% from yellow grease and 60% from soybean oil.

In the case of a 35% capacity wind site, it cannot meet the “firm power” requirement of 65% (**Figure 29**) by operating 320.1 hours per year and still achieve a 9.00% IRR. In comparing the 35% cases with and without the Biodiesel Tax Credit, it is evident that with the tax credit, one could afford to run the genset 527.4 hours annually and achieve the same internal rate of return of 9.0%. As demonstrated in **Figure 30**, a 40% capacity wind site allows the genset to be run the genset up to 507 hours per year and have a NPV of zero for the project (which captures a 9.0% IRR). A 45% capacity factor site has the ability to tolerate a higher penetration of genset operation and still maintain the IRR of 9.0% up to 693.8 hours per year. Recall that the object for the power producers with a diesel genset complementing a wind turbine is to keep operation of the genset to a minimum as long as one is certain to meet the requirements for firm power in a qualified facility. **Figures 29, 30,** and **31** contain some of the details for wind sites with capacity factors of 35%, 40% and 45%, respectively,

Figure 29.

Financial Performance of Wind Turbine on 35% Capacity Site Complemented by Genset @B75 with Diesel/ Biodiesel Prices ($1.80/$2.60) forVarious Amounts of Genset Operation

%	Hours	Diesel Price	Biodiesel Price		NPV	Cost/KWH	IRR	KWH Produced
1.00%	87.6	$1.80	$2.60	$	379,620	$ 0.05019	13.74%	5,203,440
2.00%	175.2	$1.80	$2.60	$	236,611	$ 0.05344	11.96%	5,347,980
3.00%	262.8	$1.80	$2.60	$	93,602	$ 0.05652	10.18%	5,492,520
3.65%	320.1	$1.80	$2.60	$	-	$ 0.05845	9.00%	5,587,123

Figure 30.

Financial Performance of Wind Turbine on 40% Capacity Site Complemented by Genset @B75 with Diesel/ Biodiesel Prices ($1.80/$2.60) for Various Amounts of Genset Operation

%	Hours		Diesel Price		Biodiesel Price		NPV		Cost/KWH	IRR	KWH Produced
1.00	87.6	$	1.80	$	2.60	$	684,659	$	0.04409	17.70%	5,926,140
2.00	175.2	$	1.80	$	2.60	$	541,650	$	0.04709	15.91%	6,070,680
3.00	262.8	$	1.80	$	2.60	$	398,640	$	0.04996	14.10%	6,215,220
4.00	350.4	$	1.80	$	2.60	$	255,631	$	0.05271	12.29%	6,359,760
5.00	438.0	$	1.80	$	2.60	$	112,622	$	0.05531	10.46%	6,504,300
5.79	507.0	$	1.80	$	2.60	$	-	$	0.05729	9.00%	6,618,127

Figure 31.

Financial Performance of Wind Turbine on 45% Capacity Site Complemented by Genset @B75 with Diesel/ Biodiesel Prices ($1.80/$2.60) for Various Amounts of Genset Operation

%	Hours	Diesel Price	Biodiesel Price		NPV	Cost/KWH	IRR	KWH Produced
1.00%	87.6	$1.80	$2.60	$	989,698	$ 0.03910	21.80%	6,648,840
2.00%	175.2	$1.80	$2.60	$	846,688	$ 0.04210	19.98%	6,793,380
3.00%	262.8	$1.80	$2.60	$	703,679	$ 0.04477	18.16%	6,937,920
4.00%	350.4	$1.80	$2.60	$	560,670	$ 0.04733	16.33%	7,082,460
5.00%	438.0	$1.80	$2.60	$	417,660	$ 0.04979	14.49%	7,227,000
6.00%	525.6	$1.80	$2.60	$	274,651	$ 0.05216	12.63%	7,371,540
7.00%	613.2	$1.80	$2.60	$	131,642	$ 0.05443	10.76%	7,516,080
7.92%	693.8	$1.80	$2.60	$	-	$ 0.05645	9.00%	7,649,131

Conclusions

It is technically possible to complement the electrical power production of individual or groups of wind turbines with diesel gensets. By complementing the variable nature of wind during the key summer months June-September, it is possible to produce "firm" power for 65% of the "On-Peak" hours, which are 9:00 a.m. to 9:00 p.m., Monday through Friday, except holidays. Efforts to build hybrid systems to complement wind should make wind a more attractive choice at higher penetration levels. However, there is no assurance that power companies will offer rates with adequate capacity payments for periods longer than a year. It will be difficult to establish and finance the purchase of a genset without some guarantee of payment rates for capacity and per kilowatt-hour.

Current annual tariffs posted by Xcel Energy and perhaps other power companies permit economic returns for hybrid systems with wind sites possessing capacity factors greater than 35% as long as biodiesel prices are equal to #2 diesel prices. However, there are many wind sites far superior that would have even better combined economics without being vulnerable to changing rates paid for power purchased and capacity from the genset.

The federal Biodiesel Tax Credit, which offers a credit of $1.00 per gallon for vegetable sources of oil and $.50 per gallon for recycled yellow grease will keep the two fuels approximately equal in price as they comprise B75 blends of biodiesel. If the Biodiesel Tax Credit is removed after 2008, effective prices of biodiesel can be expected to rise. Only wind sites with capacity factors of 40% or better will be able to economically operate their gensets sufficient hours to fulfill the definitions of "firm" power during "On-Peak" hours.

Wind data utilized in this study reflects capacity factors near 35% for identical wind turbines. From the hourly wind data of the months of June-September of 2003 and 2004, we calculated the need to run the genset for 416 "On-Peak" hours. It is unknown to what extent the number of hours of genset operation would be lowered on sites with capacity factors of 40% or even 45%.

The concept of hybrid electrical generation systems has been researched by others, especially in instances serving remote locations with critical needs and expensive fuel supplies. Diesel gensets have low capital costs, and that is fortunate based on the low number of hours they may need to be operated. On the other hand, their operating expenses are high, so it is advantageous to keep their hours of operation to a minimum.

This project investigated the technical solution of adding a diesel genset to complement variable flows of power from wind turbines, especially during the "On-Peak" hours of the key summer months when most areas of the U.S. face peak loads. There may be other technical solutions such as natural gas powered engines of larger scale that may be able to complement many more wind turbines, but that question is beyond the scope of this project.

Appendix 1

C E G
CONSULTING ENGINEERS GROUP
Engineering Powerful Solutions

December 13, 2005

Max Norris
Agricultural Utilization Research Institute
1501 State Street
Marshall, MN 56258

Re: Review of Research Project
Economic Analysis: Co-generation Using Wind and Biodiesel-Powered Generators by Douglas Tiffany and Vernon R. Eidman

Mr. Norris,

As the project sponsor for the above-referenced research project, AURI requested that I provide an engineering review of the completed project and assess its findings. The project is an economic review of the possibility of combining a biodiesel powered generator at a wind turbine site to produce a hybrid project that can gain additional revenue by meeting the definition of a firm power source. I make the assumption that those reading this report have familiarized themselves with the referenced study by Tiffany and Eidman.

In summary, the study provides an excellent review of the concept and its economic and policy foundations as well as a very good means of evaluation future sites. It appears to be primarily suited to smaller projects – it is not clear that it could scale up to be viable with a 100 MW wind farm, but that is not really a failing, since there are numerous smaller projects in the region and a policy bias that encourages future construction of them. It is my view that the most important point of the project deserves much greater emphasis than it received, in that the tariffs used in the evaluation are annual *(refer to page 26 of report)* – and the economic evaluations don't appear to have considered year-to-year ranges for that tariff in the evaluation. Even so, the project shows the policy change that is required to make the concept viable, even if it isn't spelled out explicitly. The change required is that the hybrid project must have a predictable (or variable based on fuel costs), long-term revenue stream that will not strand the investment in the diesel generators.

The criteria I have used in reviewing the project are as follows:

1. Is the overall proposal reasonable and technically feasible?
2. Does the success or failure of the economic model depend on any single assumption?
3. Are any major assumptions fundamentally flawed?
4. Does it appear that this generation model could have practical application – more important, would it be marketable as a completed project without undue risk to the developer?
5. Are there obvious regulatory changes required to allow hybrid generation systems to flourish in the market?

In general, the project is well-researched, clearly documented and honestly evaluates the possible use of the a hybrid generation system in which the output of wind turbines is combined with a biodiesel-fueled generator to produce a combined project that is both "green" and more or less dependable as a capacity source for generation. The greatest single weak point is the dependence on a tariff that does not appear to be in use, for reasons that I will discuss further.

Is the overall proposal reasonable and technically feasible?

First, the overall concept is of course feasible. While most of the deliberate combination of wind and diesel plants occur where the wind turbine is installed to save diesel fuel in remote locations (thus, where the overall cost of energy is already quite high), the projects have been installed – as at Guantanamo Bay, Cuba - and controlled to provide a single combined resource.

Does the success or failure of the economic model depend on any single assumption?

The economic model provided is very flexible *(see page 35 of the report)* with respect to evaluating any particular project. Since it should not be assumed that this would work for every wind installation, it is reasonable that while a single assumption could cause a particular site not to meet economic targets, the overall concept could work – in particular at high-wind-capacity sites located near adequate biodiesel production. In short, there is no single failing.

Are any major assumptions fundamentally flawed?

There is one major assumption that while not flawed is clearly a sticking point for the entire concept. It is not clear that either developers or utility companies have shown any interest in developing "firm" power diesel plants in our region. In fact, most diesel installations are specifically intended to be used only as peaking plants for a very limited number of hours per year. This is because the cost of power from these plants is considerably higher per kilowatt than for most other forms of generation, and only their relatively low cost of installed capacity makes them viable as a resource. In other words –

diesel generators are already in use quite heavily, just not as described in this project – implying that they are already serving an appropriate economic niche.

For example, Dakota Electric Association in Farmington, Minnesota (a rural electric cooperative serving Dakota County and having significant suburban load), has scores of diesel generators sized between 200 and 2000 kW enrolled in their interruptible program. These generators serve to separate the client from DEA during peak demand periods. What are significant about this are the two assumptions that drive the program – the relatively high value of the capacity for a relatively short period of time and the fact that the high cost per kWh for generation is offset by the use being limited to, on average, less than 100 hours per year.

For comparison, the study assumes (while noting that the numbers may vary), a value of \$0.037 per kW and \$ 0.062 per kWh, and run times up to 400 hrs per year. (The usual bias is for fairly high capacity values for units that run only during peak times, at very high availability.)

Further complicating matters, the nature of the electric grid and its other dispatchable resources already allows the variation in wind generation to be covered by other resources – it is not at all necessary to combine them at a single site, in fact, it is not really desirable in any technical sense, since the same biodiesel generator could be located much closer to the load in tradition 'distributed generation' models. Thus the question is simply this: Under what circumstances (other than remote installations) does this make sense?

Does it appear that this generation model could have practical application – more important, would it be marketable as a completed project without undue risk to the developer?

This is where one aspect of the project is particularly important – the observation that the economic value of the diesel generator is higher at sites with high wind capacity factors. The wind projects are paid on an energy basis, with little respect for capacity even though such capacity has value. The bias towards energy is a result of both the inability to dispatch the resource and the fact that the high capital cost makes a predictable revenue stream important. Installation of a biodiesel generator at a site that is already a pretty reliable resource in the key time periods might allow the turbine to receive credit for its natural capacity, at a moderate cost in fuel. – The point of the study then being that the diesel generator can 'firm up' the turbine at reasonable cost.

However, this structure seems to require that the combined plant be evaluated on a common *(refer to the spreadsheet on page 35)* capacity payment and a common payment for energy – since it is not important to the customer how the power was generated. Under such an agreement, the entire output is 'green', and within limits 'firm'. The objective would be to install the minimum kW of diesel generation necessary to make up for the variation in wind resource, while still hitting the given firm capacity factor. A one-for-one match between diesel and wind would describe an attempt to create a plant with dispatchable at its entire output, since the peaking capability where the diesels could be dispatched, but fuel saved by use of wind power.

I must note that the only real difficulty with the project – in fact one of the most significant points with respect to the entire concept – is the fact that there are no qualifying facilities receiving the package of payments on which the entire model is based. *(see page 26)* The obvious reason is spelled out – the fact that the rate may vary from year to year, but it still implies that as the tariffs stand, the concept might not be a good risk for a developer.

Are there obvious regulatory changes required to allow hybrid generation systems to flourish in the market?

As I described in the prior answer, it seems that the required structure would be a single value for energy and capacity based on in effect the energy cost of the wind turbine and the capacity value of the diesel generator. The diesel generator would allow the wind plant to guarantee a certain 'firm' capacity based on the amount of diesel generation installed and the consistency of the wind resource, hopefully at minimum fuel consumption. Further, this resource would be dispatchable – since the wind farms usually have SCADA connections to the utility and there is not reason NOT to use the on-site diesel generator as a peaking plant. Whether this structure should be negotiated on a plant-by-plant basis or described in a tariff is open for consideration.

If you have any further questions, please contact me to discuss the matter. I look forward to working with you to complete the installation of the demonstration installation next summer.

Sincerely,

Vincent L. Granquist, P.E.
Senior Project Engineer
Consulting Engineers Group
651-463-6350

Appendix 2.0

Additional Project Economics that Test Alternatives Involving: Power Price, Capacity Payments, and Peak Production Months

Reviewer comments contained in Appendix 1.0 suggest additional analyses to test the stability of modeled results in addition to those identified and presented in the original paper. These are worthy inquiries grounded in utility experience that enhance the conclusions reached in the original paper. The conclusions reached in the original paper remain intact, but the assumptions modeled here in Appendix 2.0 and their conclusions offer additional information regarding the prospects of utilizing gensets utilizing biodiesel blends to complement wind turbines.

Single Rate Issue

Reviewer comments suggest that a single rate be paid for electricity produced by the wind turbine and the genset. The original paper utilized $.033 per kilowatt-hour for the electricity from wind production, which is the standard wind tariff offered in Minnesota. Payments levels for the electricity produced by the genset were based on the published Xcel A52 tariffs, which were $.0620 per kilowatt-hour for on-peak energy produced between June and September. In addition, capacity payments of $.0367 were calculated for the on-peak hours of the same period.[27] The original analysis was conducted assuming that co-generation activity for the key June through September period would establish a wind turbine-genset combination as a “qualified facility” under existing regulations, although no proposal have been made nor accepted for such a facility by that company.

Capacity Payment Issue with Additional Months of Firm Power

Reviewer responses suggested that analyses be conducted that incorporate the operation of gensets for several months in addition to the key June-September period. The original paper utilized the hourly production data supplied by Minnkota Electric to determine the power production by wind turbines during the on-peak hours (9:00 a.m. – 9:00 p.m., Monday-Friday, excluding holidays) during the months of June-September. The wind hourly data was analyzed to determine the number of hours a diesel genset would be required to run at nameplate capacity for the hybrid system to achieve 65% firm power during the period. The original assumptions were accepted because they represented the key times of the year when utilities require and are willing to pay for reliable power. The June-September period is also the time when output of wind turbines is poorest.

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[27] Northern States Power Company, Minnesota Electric Rate Book-MPUC No.2, Section 9, 7th Revised Sheet No. 4, Effective Date: 01-01-05. Website: www.xcelenergy.com/docs/corpcomm/Me_Section_9.pdf.

Additional Analyses Completed at Reviewer Suggestion

To accommodate the convention of a utility having a single rate and a single meter for the combined wind turbine and genset facility, the power purchase rate of $.038 was suggested by the reviewer and modeled. Additional months of firm power production were also modeled, going from the four months of June-September in the original paper to five and six months, by adding May and October sequentially. In order to add additional months, analysis was performed on the datasets of Minnkota Electric in order to determine the amount of time gensets could be expected to operate in order to have the combined facility of wind turbine and genset achieve 65% firm power during on-peak hours. **Table 1A** shows the number of hours of genset operation needed to achieve firm threshold levels, rising from 415.74 hours for June-Sept., to 496.25 for May-Sept., and finally 566.68 for the half year from May-Oct. When months outside of June-Sept. are added, the capacity payment rate must be adjusted. This was done in accordance with the payment rate of $.0070 applied in the months of May and October and $.0367 applied to the June-Sept. period. [28]

[28] Ibid.

Table 1A.

Hours of Genset Operation at Nameplate Needed to Reach Combined 65% Capacity with Wind Turbine for On-Peak Hours of May-Oct. at Valley City and Petersburg, ND

	May	June	July	Aug	Sept.	Oct.	Totals per Site and Year
Valley City 2003	83.71	107.57	122.28	107.64	69.44	91.05	**581.69**
Valley City 2004	69.39	84.34	138.84	111.55	96.81	49.10	**550.03**
Petersburg 2003	86.15	106.8	129.11	106.4	57.28	90.19	**575.93**
Petersburg 2004	82.76	79.45	140.78	113.39	91.29	51.41	**559.08**
Mean Hours	**80.50**	**94.54**	**132.75**	**109.75**	**78.71**	**70.44**	**566.68**

Hours of Genset Operation at Nameplate Needed to Reach Combined 65% Capacity with Wind Turbine for On-Peak Hours of May-Sept. at Valley City and Petersburg, ND

	May	June	July	Aug	Sept.	Totals per Site and Year
Valley City 2003	83.71	107.57	122.28	107.64	69.44	**490.64**
Valley City 2004	69.39	84.34	138.84	111.55	96.81	**500.93**
Petersburg 2003	86.15	106.8	129.11	106.4	57.28	**485.74**
Petersburg 2004	82.76	79.45	140.78	113.39	91.29	**507.67**
Mean Hours	**80.50**	**94.54**	**132.75**	**109.75**	**78.71**	**496.25**

Hours of Genset Operation at Nameplate Needed to Reach Combined 65% Capacity with Wind Turbine for On-Peak Hours of June-Sept. at Valley City and Petersburg, ND

	June	July	Aug	Sept.	Totals per Site and Year
Valley City 2003	107.57	122.28	107.64	69.44	**406.93**
Valley City 2004	84.34	138.84	111.55	96.81	**431.54**
Petersburg 2003	106.8	129.11	106.4	57.28	**399.59**
Petersburg 2004	79.45	140.78	113.39	91.29	**424.91**
Mean Hours	**94.54**	**132.75**	**109.75**	**78.71**	**415.74**

Conclusions of Additional Analysis

Table 2A contains the internal rates of return for various wind + genset projects. The projects are divided between those based on sites with wind capacity factors of 35% and 40%, and then further divided by the payment rates received and the time required to achieve 65% firm, whether four months, five months, or six months. B75 blends of biodiesel were modeled with prices assumed at ($1.80/ $1.80) of diesel and biodiesel due to the influence of the Biodiesel Excise Tax Credit.

Table 2A. Internal Rates of Return of Projects

	Wind + Genset	Wind Alone
35% Capacity Factor Site		
4 Months, Original Rates (a)	10.39%	13.30%
4 Months, Revised Rates (b)	11.39%	17.16%
5 Months, Revised Rates (c)	8.40%	17.16%
6 Months, Revised Rates (d)	6.05%	17.16%
40% Capacity Factor Site		
4 Months, Original Rates (a)	14.32%	18.70%
4 Months, Revised Rates (b)	15.75%	23.14%
5 Months, Revised Rates (c)	12.74%	23.14%
6 Months, Revised Rates (d)	10.39%	23.14%

The effect of the higher single payment rate of $.038 is evident in the higher internal rate of return calculated for the revised rate four month scenarios, with higher returns shown for both the 35% and 40% capacity factor sites. As wind turbine + genset operations are modeled for scenarios conforming to requirements to produce firm power at 65% of nameplate capacity for periods from four to six months, internal rates of return raise slightly due to the lower payment levels for On-Peak capacity offered in the months of May and October, which are based on the rate of $.0070 per kilowatt-hour versus $.0367 in the June-September period. The costs of genset operation during the additional months of May and October are not large enough to drastically reduce the internal rates of return for the five and six month scenarios, while receipt of capacity payments for a longer period of time is favorable.

Summary

The concept of complementing wind with biodiesel-powered gensets has been substantiated using a single rate for wind and genset power and for periods of four, five, and six months of firm, On-Peak operation.

Appendix 3

C E G

CONSULTING ENGINEERS GROUP

Engineering Powerful Solutions

January 14, 2006

Max Norris
Agricultural Utilization Research Institute
1501 State Street
Marshall, MN 56258

Re: Review of Research Project
Economic Analysis: Co-generation Using Wind and Biodiesel-Powered Generators by Douglas Tiffany and Vernon R. Eidman
As modified with Appendix 2 in response to prior comments

Mr. Norris,

As the project sponsor for the above-referenced research project, AURI requested that I provide an engineering review of the completed project and assess its findings. This letter is a follow up to my comments in my letter to you of December 13, 2005, our conference call with Doug Tiffany after those comments, and further work on the paper.

The paper has been modified by the attachment of my earlier comments as 'Appendix 1' and by further evaluation by the author 'Appendix 2.0'. Per my discussion with Mr. Tiffany, these final comments will be attached as 'Appendix 3' and should conclude the task. The report as it stands is complete and is useful and applicable to the utility market.

After the initial paper was submitted, we asked Mr. Tiffany to re-run a couple of calculations with a change in the base spreadsheet. We suggested that the combined wind and diesel project must be on a single electric rate (this is conventional utility practice), and that it should explore months other than the peak summer months. The second suggestion came as a result of CEG's conversations with Xcel Energy regarding the rate used in the project.

It is not clear that the project would be allowed to meet capacity requirements during just the four months of the year when capacity payments were highest – the rate is silent with regard to the number of months that 65% must be hit, but our assumption is that the utility would perceive using only 4 as 'gaming' the system and would change the rate. Xcel Energy (Barbara O'Neil and John Chow) suggested that the utility would probably require 9 months meeting capacity – thus including 5 'off-peak' months. A final answer on this is pending from Xcel Energy, but until they are approached with a real project the answer is merely a well-informed estimate, not firm policy. Our view was that we needed to know if the extra months burdened the proposed project in an undue manner. It does not appear to have been the ‘concept killer’ we feared.

A review of Appendix 2.0 indicates that the revisions have been properly considered and that a combined wind/diesel project on rate A52 could be viable and attractive to the utility. Our discussions with Xcel Energy seemed to back up that assumption, in that the combined project should qualify for the rate and be of interest in a general sense. We do note that this probably only applies to new wind/diesel projects, since the long-term contracts for existing wind farms are in many respects beneficial to Xcel Energy, and conversion of an existing site to this new concept would require that it benefit both parties – which probably would not be the case on the A52 rate, since it appears that the utility would be paying a premium for wind power they were going to receive at a lower rate under the long term contract.

In conclusion, with the addition of the additional analysis in Appendix 2.0, I consider this project to have met all of the stated objectives and judge it to be complete. The proposed wind/diesel combination could be applicable to a utility generation portfolio at rates that are not unreasonable by existing tariff standards, and appear economically viable within the limits discussed in the report.

If you have any further questions, please contact me to discuss the matter.

Sincerely,

Vincent L. Granquist, P.E.
Senior Project Engineer
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651-463-6350

Appendix 4

At the request of the contractor, an additional simulation was modeled to conform to the conditions of an extended test run of the diesel genset. The conditions conformed to the following:

1) The wind turbine would be on a site with a 40% capacity factor.
2) The wind turbine would be a 1.65 MegaWatt unit.
3) The genset would run on B100.
4) The price of biodiesel would be $1.75 per gallon.
5) The genset would run for 400 hours per year.
6) The price for purchased power would be $.038 per kWh
7) The price for capacity would be $.0367 per kWh.

Figure 4-A shows the conditions modeled for this hybrid system including the price paid for power, which is $.038 per kWh and $.037 per kWh for capacity when the 65% firm threshold is met for On-Peak hours. While a 40% capacity factor wind site produces an internal rate of return (IRR) of 23.24%, operation of the diesel genset using B100 for 400 hours per year reduces the overall IRR to 16.16% .

Figure 4-A

Diesel Genset Production Economics

by Douglas G. Tiffany, Dept. of Applied Economics, University of Minnesota
7/14/2006

Assumptions:

Diesel Genset Capacity	1.650	MW			
Capacity Factor for Genset	4.57	%	Percent Equity		40.00%
Hours of Annual Operation	400.0	Hours	Percent Debt		60.00%
Annual Production	660,000	KWH	Interest Rate		7.00%
Price for Purchased Power	$0.0380	per KWH			
Price for Power Capacity	$0.0367	per KWH	Price of Diesel		$0.00
Discount Factor	9.00%		Price of Biodiesel		$1.75
Salvage Value(+)/Removal Cost (-)	$45,000		Blend	B	100

Conclusions:

		Genset Alone	Wind Alone	Wind & Genset
NPV of 20 Yr. Project		-257,380	819,470	562,089
Average Cost per KWH		$0.20438	$0.03197	$0.04963
IRR for Project		#DIV/0!	23.14%	16.16%
Annual Production	(kWh)	660,000	5,781,600	6,441,600
Petro-Diesel Gallons		0		
Biodiesel Gallons (B100)		47,475		
Total Gallons of Fuel		47,475		

	1,0	Initial	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Capital Expenditures																						
Interconnection Fees		5,000																				
Site & Service Road Acquisition		5,000																				
Tanks and Building		100,000																				
Diesel Genset with swithgear		350,000																				
Transmission Feeder Lines		25,000																				
Salvage Value(+)/Removal Cost(-)																						-45,000
Total Capital Expenditures		485,000																				-45,000
Revenue or Credits																						
Power Purchased	1	0	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080	25,080
Power Capacity Payment	1	0	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401
Production Tax Credit (Federal)	0	0																				
Small Wind Producer Payment (MN	0	0																				
Sale of Green-Tags @.01/kWh	1	0																				
USDA Rural Develop. Grant	1	0																				
Total Revenue or Credits		0	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481	113,481
Operating Expenses																						
Maintenance Plan		0	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095
Debt Service (P+I)			41,432	41,432	41,432	41,432	41,432	41,432	41,432	41,432	41,432	41,432										
Insurance		0	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Fuel Cost		0	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081	83,081
Property Taxes			675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Total Operating Expenses		0	133,608	133,608	133,608	133,608	133,608	133,608	133,608	133,608	133,608	133,608	92,176	92,176	92,176	92,176	92,176	92,176	92,176	92,176	92,176	92,176
Net Cash Flow		-194,000	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	21,305	21,305	21,305	21,305	21,305	21,305	21,305	21,305	21,305	66,305
Disc. Cash Flow of Year		-194,000	-18,465	-16,940	-15,541	-14,258	-13,081	-12,001	-11,010	-10,101	-9,267	-8,502	8,256	7,575	6,949	6,376	5,849	5,366	4,923	4,517	4,144	11,831
		Initial	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Net Present Value of Project		-257,380																				
Net Cash Flow Genset		-194,000	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	-20,127	21,305	21,305	21,305	21,305	21,305	21,305	21,305	21,305	21,305	66,305
Net Cash Flow Wind		-662,000	158,977	158,977	147,577	147,577	147,577	147,577	147,577	147,577	147,577	147,577	179,107	179,107	179,107	179,107	179,107	179,107	179,107	179,107	179,107	340,407
Combined Net Cash Flow		-856,000	138,850	138,850	127,450	127,450	127,450	127,450	127,450	127,450	127,450	127,450	200,412	200,412	200,412	200,412	200,412	200,412	200,412	200,412	200,412	406,712