[Return to Product List]

USING WIND POWER TO OFFSET THE ENERGY REQUIREMENTS OF CO_2 COMPRESSION FOR SEQUESTRATION: A BEST PRACTICES MANUAL

Deliverable Report

Prepared for:

Darin Damiani

U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
PO Box 880
Morgantown, WV 26507-0880

Cooperative Agreement No. DE-FC26-05NT42592

Melanie D. Jensen
Bradley G. Stevens
Kerryanne M.B. Leroux
Troy K. Simonsen
Edward N. Steadman
John A. Harju

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

October 2007

DOE DISCLAIMER

EERC DISCLAIMER

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Plains CO_2 Reduction (PCOR) Partnership

USING WIND POWER TO OFFSET THE ENERGY REQUIREMENTS OF CO_2 COMPRESSION FOR SEQUESTRATION: A BEST PRACTICES MANUAL

Melanie D. Jensen, Energy & Environmental Research Center
Bradley G. Stevens, Energy & Environmental Research Center
Kerryanne M.B. Leroux, Energy & Environmental Research Center
Troy K. Simonsen, Energy & Environmental Research Center
Edward N. Steadman, Energy & Environmental Research Center
John A. Harju, Energy & Environmental Research Center

October 2007

EXECUTIVE SUMMARY

This best practices manual (BPM), developed by the Plains CO_2 Reduction (PCOR) Partnership, illustrates the steps required to estimate the applicability of using wind resources to offset some of the fossil fuel-generated electricity needed for carbon dioxide (CO_2) geologic sequestration activities. The power generated could be fed directly to a transmission line or used directly in the sequestration activities.

Geologic sequestration of CO_2 requires energy for capture, separation, compression, and injection. The most likely steps for which power from wind resources could be used are the compression and injection steps. When fossil fuel-produced electricity is used for these steps, it reduces the amount of power that is available to be transmitted to the grid. Wind power could be used to provide energy for some of the equipment needed for sequestration, eliminating some of this "energy penalty."

Some opportunity may exist to use wind energy to power compression of CO_2 in enhanced oil recovery (EOR) and enhanced coalbed methane (ECBM) production if it can be integrated without impacting the operational needs of the end users.

In addition, injection of CO_2 strictly for sequestering purposes would also be a viable process for utilizing wind energy to drive the compression step since the process would not be determined by an end user's operational requirement.

It should be noted that in any case where it is operationally feasible to utilize wind energy to compress and deliver the CO_2, emissions from the source, assuming the source is a continuous process, will have to be emitted during times when the wind energy system is idle.

To determine the CO_2 emissions that can be offset through the use of wind power, the quantity of CO_2 that is emitted during the production of the electricity needed must be estimated, taking into account the fossil fuel type and generator design.

The available wind resources can be estimated from wind resource maps if measurements cannot be taken at the actual location. Assuming that the wind resources are sufficient for operating wind turbines, the power requirements of the sequestration step (e.g., pipeline compression) are determined and the number of wind turbines needed to generate that much electricity is calculated.

Finally, the cost of the power produced by the wind turbines is estimated, including any offsets in terms of carbon credits and tax credits. The CO_2 emissions that will be avoided by utilizing wind power can be determined as well.

A case study investigating the use of wind energy to replace lignite-produced electricity for CO_2 compression estimated an economically viable revenue of $3.2 million annually and a 13-yr simple payback. Eighteen 1.5-MW wind turbines are required to match the 27-MW demand of the compressors for a CO_2 pipeline located in western North Dakota. The capital investment is $40.5 million to generate approximately 70,800 MWh. Interest is estimated at $1.5 million annually, assuming a 6% loan. Utilization of wind energy in this case study would generate 86,400 short tons of carbon credits. The potential revenue from carbon credits is $350,000 annually using the average price of $4.05 per short ton CO_2. Other income or savings include the production tax credit ($1.3 million) and electricity savings from utilizing wind energy ($3.0 million). Economic viability was based on a 20-year service life for the wind turbines.

Having access to information such as can be produced using this BPM allows decision makers to make more informed choices about how best to sequester CO_2 and when to consider wind generation as an option to offset compression and injection penalties.

Plains CO_2 Reduction (PCOR) Partnership

USING WIND POWER TO OFFSET THE ENERGY REQUIREMENTS OF CO_2 COMPRESSION FOR SEQUESTRATION: A BEST PRACTICES MANUAL

Melanie D. Jensen, Energy & Environmental Research Center
Bradley G. Stevens, Energy & Environmental Research Center
Kerryanne M.B. Leroux, Energy & Environmental Research Center
Troy K. Simonsen, Energy & Environmental Research Center
Edward N. Steadman, Energy & Environmental Research Center
John A. Harju, Energy & Environmental Research Center

October 2007

INTRODUCTION

Greenhouse gases, including carbon dioxide (CO_2), trap a portion of the sun's energy in the Earth's atmosphere and make our planet warm enough to support life. Human (anthropogenic) activity, including the use of fossil fuel, generates a significant volume of greenhouse gases such as CO_2. There is concern that the anthropogenic greenhouse gases entering the atmosphere are causing increased warming and that this warming will affect climate on a global scale. The capture and long-term storage of CO_2 could help to stabilize and eventually reduce CO_2 levels in the atmosphere.

Each year, humans release CO_2 into the atmosphere through fossil fuel use, farming, industrial activity, and the like. World governments and industries can curb the growth of CO_2 levels in the atmosphere by reduction of emissions and/or through sequestration. Sequestration refers to the storage of CO_2. For example, plants remove CO_2 from the atmosphere through photosynthesis and store it as organic matter in the soil. Similarly, industry can extract CO_2 from its emissions and store it underground. Reductions in emissions can also be achieved by improving process efficiency, utilizing cleaner fossil fuels, and/or decreasing fossil fuel consumption.

Renewable energy (such as wind power) will be useful for all of these approaches. Renewable energy can offset or displace energy from fossil fuels, thereby reducing the consumption of fossil fuel. It can also be used to provide at least a portion of the energy required to extract CO_2 from exhaust gases or power the pumps and compressors that are used to transport CO_2 into the ground for storage. As of the beginning of the 21st century, wind energy is the low-cost emerging renewable energy resource. State-of-the art wind power plants produce energy at a cost that is competitive with energy from fossil fuels when federal tax credits or other incentives are available (American Wind Energy Association, 2007).

Wind energy can be used to replace at least a portion of the energy required by various processes, reducing or eliminating their CO_2 emissions. The United States currently does not regulate CO_2 emissions, although the growing concern over greenhouse gases may change this. One strategy put forth by the Kyoto Conference is the use of an emission credit market (U.S. Department of State, 1998). In the United States, a carbon market is developing as well. If the demand for carbon offsets continues to grow, renewable energy projects would likely increase, including the use of wind energy.

CO_2 EMISSION REDUCTION OPTIONS

CO_2 emissions can be limited through processing changes (such as increased efficiency, improved capture methods, and/or changes in fuel type), by capture and long-term storage, and by removal from the atmosphere with subsequent storage in soils and plants. The storage of CO_2 is referred to as sequestration. There are two types of CO_2 sequestration: geologic and terrestrial.

Terrestrial CO_2 sequestration involves capturing CO_2 that has already been released to the atmosphere through uptake by plants or by fixing carbon in the soil. Improved land management can increase organic matter in the soil, thereby reducing the amount of CO_2 in the atmosphere. Replacing petroleum fuels with renewable fuels, such as ethanol or biodiesel, in the equipment used for land management can increase the overall effectiveness of terrestrial sequestration. For example, farmers who irrigate their crops may replace pumps that require fossil fuel with those that can operate on renewable energy, which would reduce current CO_2 emissions.

Geologic CO_2 sequestration involves capturing CO_2 at its point of generation before it is released to the atmosphere. During this type of sequestration, CO_2 is removed from the exhaust stream of factories and power plants and is stored deep underground in a secure geologic formation. Storage is long-term (thousands of years) and environmentally sound. Geologic sequestration requires energy to capture, separate, compress, transport (typically via pipeline), and inject CO_2. In addition to providing a method for sequestering CO_2, geologic sequestration can also provide a positive technical and economic benefit when utilized for either enhanced oil recovery (EOR) or enhanced coalbed methane (ECBM) recovery.

Pipeline Transportation

Transport of large quantities of CO_2 is usually performed by pipeline. The United States has several CO_2 pipeline networks, most of which are located in Texas, New Mexico, and Colorado. In the future, a broader network of CO_2 pipelines may be constructed to accommodate movement of captured CO_2 for use in EOR, ECBM recovery, or for sequestration. It should be noted that CO_2 delivered for the purpose of EOR and conventional sequestration is done so under a supercritical state, and in the case of CO_2 delivered for ECBM, the CO_2 is in the gaseous phase. The initial legs of a pipeline system probably will be developed for EOR projects and will be used for saline formation injection after the EOR opportunities have been exhausted. The CO_2 sources that are first adopters will benefit from the revenues produced through the commercial sale of CO_2. Once carbon markets fully develop, the economics of carbon credit trading will control the development of sequestration opportunities.

Geologic Sequestration in a Saline Formation

While the injection of captured CO_2 into saline formations is considered to be an emerging approach to carbon management, the concept has been evaluated in the field at scales ranging from experimental (one-time injection of a few thousand tons at Frio in Texas) to commercial (ongoing injection of 1 million tons a year at Sleipner in the North Sea). Numerous research-oriented projects focused on the injection of CO_2 into brine formations at several locations throughout the world are planned for the near future.

Mechanistically, the CO_2 capacity of a brine formation may be considered in terms of free-phase CO_2 in the pore space of the rock, dissolved-phase CO_2 in the formation water, and CO_2 converted to solid minerals that become part of the rock matrix. The degree to which each mechanism will affect sequestration under the range of geologic, hydrodynamic, and geochemical conditions that can occur in any given location is currently not well understood and is difficult to predict.

Enhanced Oil Recovery

Oil can be produced from a reservoir in three distinct phases, or stages, of operation. During the first stage, commonly referred to as the primary recovery phase, the production of oil is driven primarily by the natural pressure of the oil field. Once the rate of primary production has fallen below an economically acceptable rate, an operator may choose to stimulate production by a variety of means, which is collectively referred to as EOR operations. Secondary-phase EOR typically involves the injection of large volumes of water into the production zone to maintain reservoir pressure and to sweep oil from the reservoir. This technique is commonly referred to as waterflooding, or waterflood EOR. In many cases, it can be conducted economically for decades longer than the primary recovery phase. The secondary recovery stage reaches its limit when the injected water is produced in considerable amounts along with the oil and the overall production of the reservoir is no longer economical. The successive use of primary recovery and secondary recovery in an oil reservoir typically produces about 15% to 40% of the original oil in place (OOIP). If economic and technical conditions are favorable, an operator may elect to move the reservoir into a third, or tertiary, stage of oil production. Tertiary EOR techniques are generally centered around the injection of fluids that alter the original properties of the oil in the reservoir—most often CO_2. The injection of CO_2 not only restores pressure, but the dissolution of CO_2 into the oil also lowers its viscosity, improves oil displacement and flow in the reservoir, and incrementally increases its productivity. As with waterflooding, CO_2-based EOR can increase the operational lifetime of an oil field by decades.

Enhanced Coalbed Methane Recovery

Numerous laboratory- and field-based studies have shown that coal beds can have significant capacities for sequestering CO_2 (Nelson et al., 2005). Coal can physically adsorb many gases and has a higher affinity for CO_2 than for methane (Chikatamarla and Bustin, 2003). Gaseous CO_2 injected into a coal seam will flow through the cleat system and become adsorbed onto the coal surface, effectively replacing and releasing gases with lower affinity for coal, such as methane. The injection of gaseous CO_2 into a coal seam can result in simultaneous sequestration of CO_2 and ECBM production.

Issues and Opportunities Related to the Use of Wind Energy for Compression of CO_2

If the energy used in the process is derived from fossil fuels, then the net effect of CO_2 sequestration is less. Use of renewable energy provides a means to maximize the efficiency of sequestration processes with respect to net CO_2 emissions. Wind energy can produce power for equipment used in the removal of CO_2 from exhaust gases or power to the equipment used to store CO_2 during geologic sequestration (specifically compression). A case study is presented in Appendix A that investigates the use of wind energy to replace lignite-produced electricity for CO_2 compression.

Much of the focus of this document has been on the use of wind energy to power the compression of CO_2. As stated previously, CO_2 for use in EOR and conventional sequestration is compressed to and delivered in a supercritical state. In other words the compressed CO_2 acts more like a liquid than a gas, with specific gravities of 0.9 to 0.95. This makes the pipeline pressure very responsive to changes at the compression step, which would take place if wind energy was the sole power provider for the compressors. In the case of EOR, this pipeline responsiveness also means that the end user senses any changes at the compression step quickly as well. Based on our understanding of the EOR process, operators of oil fields utilizing EOR would not be tolerant of the intermittency that wind energy-driven compression would provide.

With that said, some opportunity may exist to use wind energy to power compression of CO_2 in EOR where compressed CO_2 is delivered to suitable underground storage as in the saline formation sequestration process and, when sufficient volume has been accumulated, EOR users could draw on the CO_2 reservoir for EOR requirements. In this scenario, the underground reservoir provides the surge capacity to mitigate the intermittency of the wind energy.

Wind energy-driven compression would also be a technically feasible option when the CO_2 is utilized for ECBM production. In ECBM production CO_2 is injected as a gas and the process does not require a continuous supply of CO_2 for the resulting enhanced recovery of methane. In addition, injection of CO_2 for strictly sequestering purposes would also be a viable process for utilizing wind energy to drive the compression step since the process would not be determined by an end user's operational requirement. It should be noted that in both of these cases, the CO_2 emissions from the source, if the source is a continuous process, will have to be emitted during times when the wind energy system is idle.

A method that can be used to determine the number of wind turbines needed and the amount of CO_2 emissions that could be avoided through the use of wind energy is outlined in the following sections.

QUANTIFICATION OF CO_2 EMISSIONS

Fossil fuels play a critical role in meeting electricity demands. Data collected by the U.S. Energy Information Administration (EIA) indicate that over 70% of U.S. electricity is derived from fossil fuels (Energy Information Administration, 2007a). This is shown in Table 1. Consequently, the electric power industry is a significant emitter of CO_2. Renewable energy can play an important role in reducing emissions from the electric power industry by offsetting fossil fuel consumption.

Table 1. Percentage of Electricity Produced in the United States in 2006 by Various Fossil Fuels (Energy Information Administration, 2007a)

Fuel Type	Percentage
Coal	49.0
Natural Gas	20.0
Petroleum	1.6
Other Gases	0.4
Total % of U.S. Production	71.0

The quantity of CO_2 produced during the generation of electric power depends upon the fuel, generator type, facility design, and emission controls. The generator type and facility design determine the efficiency of the power plant, which impacts CO_2 emissions. Plant efficiency is never 100% because energy is lost in both the conversion and transfer processes. The type of generator significantly impacts the extraction of energy from the fossil fuel, while facility design determines the transmission efficiency of energy between the generator and power lines.

The majority of power generation facilities across the United States utilize one of the following four types of generators: steam turbine, combustion turbine, internal combustion engine, or combined-cycle turbine (Energy Information Administration, 2007b). Thermal efficiencies for each of these generators vary and are also dependent on fuel type.

The first step in determining how much CO_2 can be offset by wind power is quantifying the CO_2 emissions. Sometimes the quantity of CO_2 that is emitted is known. When it is not, or when a specific facility has not been identified, the quantity can be estimated. The quantity of CO_2 emitted during the generation of electricity can be estimated by dividing the fuel's CO_2 emission coefficient by the average facility efficiency for a given generation method. The data needed for this estimation are available from EIA. One method of calculating the CO_2 emissions is presented in the following paragraphs.

The type of fuel used by a power generation facility has the greatest impact on CO_2 emission rates. EIA provides statistics on the quantity of CO_2 produced from the combustion of various fossil fuels. These values, called CO_2 emission coefficients, are listed in Table 2. The amount of CO_2 generated per unit of electricity can be calculated for coal and other common

Table 2. EIA Fossil Fuel Emission Coefficients (Energy Information Administration, 2007c)

Fossil Fuel	CO_2 Emission Coefficients		
	lb CO_2 per Unit	Unit	lb CO_2 per Million Btu
Aviation Gasoline	18.4	gal	152.7
Distillate Fuel (No. 1, No. 2, No. 4 fuel oil and diesel)	22.4	gal	161.4
Jet Fuel	21.1	gal	156.3
Kerosene	21.5	gal	159.5
Liquified Petroleum Gases	12.8	gal	139.0
Motor Gasoline	19.6	gal	156.4
Petroleum Coke	6768.7	ton[a]	225.1
Residual Fuel (No. 5 and No. 6 fuel oil)	26.0	gal	173.9
Methane	116.4	mcf[b]	115.3
Flare Gas	133.8	mcf	120.7
Natural Gas	120.6	mcf	117.1
Propane	12.7	gal	139.2
Anthracite	3852.2	ton	227.4
Bituminous Coal	4931.3	ton	205.3
Subbituminous Coal	3715.9	ton	212.7
Lignite	2791.6	ton	215.4

[a] Short ton.
[b] Thousand cubic feet.

types of fossil fuels. In addition to the CO_2 emission coefficient, estimation of annual CO_2 emission should also take into account the energy efficiency of the power plant. EIA provides monthly and annual data on power generation, method of generation, fuel type, and fuel consumption for nearly all of the power generation plants in the United States (Energy Information Administration, 2007d).

The annual power production for each generator type is summed, divided by the annual power production total for power plants using that fuel, and converted to a percentage. The percentage that was calculated from the EIA data for 2005 for each generator type is listed in the third column of Table 3, which summarizes CO_2 emissions from utilities.

Next, power plant energy efficiencies are calculated from fuel consumption rates and net generation statistics. This information is provided by EIA (Energy Information Administration, 2007e). Net annual generation of electricity (in units of MWh) and annual fuel consumption are determined for each facility. Consumption values are converted from Btu to MWh. The data are then sorted by fuel type and generation method within fuel type. For each facility, the electricity generated is divided by the fuel consumption and the resulting fraction converted to a percentage. As an example, the percentages for several fuel–generation method combinations were averaged; the average values are shown on Table 3. Percentages greater than 100% or less than or equal to zero were eliminated as they did not represent reliable data. Each percentage shown in Table 3 represents the average power plant energy efficiency for a particular facility, taking into account generation and fuel type.

Table 3. CO_2 Emissions During the Conversion of Various Fossil Fuels to Electricity at Utilities

Fuel Type	Method of Generation	Electricity from Generation Method by Fuel Type, %	Power Plant Energy Efficiency[a], %	Fuel Emission Coefficient[b], lb CO_2/million Btu	Facility Emissions, short ton CO_2/MWh	Weighted Average CO_2 Emissions, short ton CO_2/MWh
Distillate Fuel Oil	Steam turbine	29.1	31.3	161.4	0.88	1.01
	Combustion turbine	33.9	21.5	161.4	1.28	
	Internal combustion engine	13.6	29.8	161.4	0.92	
	Combined-cycle turbine	23.1	32.5	161.4	0.85	
Petroleum Coke	Steam turbine	> 99.9	33.5	225.1	1.15	1.15
Residual Fuel Oil	Steam turbine	97.9	34.1	173.9	0.87	0.88
	Combustion turbine	0.4	21.5	173.9	1.38	
	Internal combustion engine	0.1	28.2	173.9	1.05	
	Combined-cycle turbine	1.6	24.6	173.9	1.21	
Natural Gas	Steam turbine	14.1	30.7	117.1	0.65	0.57
	Combustion Turbine	11.0	26.4	117.1	0.76	
	Internal combustion engine	0.2	28.3	117.1	0.71	
	Combined-cycle turbine	70.8	35.7	117.1	0.56	
Coal	Steam turbine (anthracite and bituminous coal)	54.0	35.2	205.3	1.00	1.05
	Steam turbine (lignite)	4.7	30.1	215.4	1.22	
	Steam turbine (subbituminous coal)	41.3	32.7	212.7	1.11	

[a] Energy efficiency was calculated from 2005 fuel consumption and generation data provided to EIA by utility and nonutility power plants (Energy Information Administration, 2007d).
[b] Energy Information Administration, 2007c.

Finally, the estimates of power plant energy efficiencies and CO_2 emission coefficients can be used to determine the amount of CO_2 produced per MWh of generation. From Table 2, it can be seen that natural gas, for example, produces about 117 pounds of CO_2 for every million Btu of generated energy. This can be converted to lb CO_2/MWh using Equation 1.

$$\frac{117\ lb\,CO_2}{1\ million\ Btu} \times \frac{1\ million\ Btu}{0.293\,MWh} = 399\ lb\,CO_2\ /\ MWh \qquad \text{[Eq. 1]}$$

Energy losses in any facility result in the consumption of a larger amount of fuel to generate a megawatt (MW) of power. The energy losses are reflected in the power plant energy efficiencies. When an emission coefficient is divided by the power plant energy efficiency, the result is a more accurate emission rate. For example, a natural gas facility with a combined-cycle turbine has an energy efficiency of roughly 36%, so the emission rate for the facility is 0.55 short tons/MWh, as shown by Equation 2.

$$\frac{399\ \text{lb CO}_2/\text{MWh}}{0.36} \times \frac{1\ \text{ton}}{2000\ \text{lb}} = 0.55\ \text{tons}/\text{MWh}$$

[Eq. 2]

Column six of Table 3 provides the calculated emissions for various types of power generation facilities. The weighted average CO_2 emission for a fuel type is calculated by multiplying the CO_2 emission coefficient for a generation method by the fraction of electricity produced by that generation method for a given fuel type. All of the generation values are added together to get the weighted average emissions for a specific fuel type.

The type of fuel has a greater impact on the production of CO_2 than the method of generation. In fact, differences in the CO_2 emission coefficient between methods are not statistically significant. A weighted average was, therefore, calculated for each fuel type. Petroleum coke power generation facilities emit, on average, the largest amount of CO_2 per MWh of electricity.

WIND RESOURCE ASSESSMENT WITH RESPECT TO THE DEVELOPMENT OF WIND FARMS

Wind resources are typically evaluated using direct measurement methods. They can also be estimated using wind resource maps. The wind resources of the PCOR Partnership region will be used as an example to illustrate the latter approach.

The PCOR Partnership has identified CO_2 sources and sinks for geologic sequestration projects across the PCOR Partnership region. Sinks include oil fields that are candidates for EOR, unminable coalbeds, depleted oil and gas zones, and deep saline reservoirs. Geographical information systems (GISs) were used to compare locations of these CO_2 sinks and sources to potential areas for wind development. Figure 1 illustrates the data sets as viewed in GIS over the

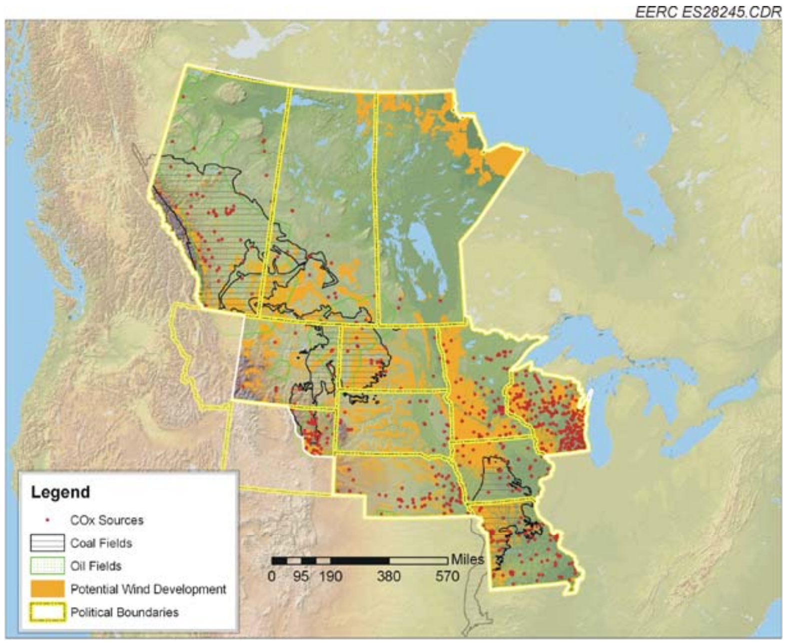

Figure 1. Coalfields (black), oil fields (light green), and sources of CO_2 (red dots) are superimposed on a map of the PCOR Partnership region, with areas of potential wind development shaded in orange.

entire PCOR Partnership region. Wind resource information was gathered from individual state wind resource maps and the Canadian Wind Energy Atlas (Energy & Environmental Research Center, 2006; Canadian Wind Energy Atlas, 2006). These maps were created based on in situ and model-derived data at a height of 164 ft above ground level. The state resource maps were not all generated using the same methodology and the wind data available for the generation and validation of each map also varied from state to state. As a result, discontinuities are evident in the wind resource across the state and country borders.

Wind power density (WPD) data, if not provided by the data sets, can be calculated from wind speed and air density data. The National Renewable Energy Laboratory's wind resource classification system can be used to classify WPD data into seven categories, shown in Table 4. In this classification system, the larger the class number, the better the wind resource.

Table 4. National Renewable Energy Laboratory Wind Power Classification System

Wind Power Class	Resource Potential	Wind Power Density at 50 m, W/m^2	Wind Speed[a] at 50 m, m/s	Wind Speed[a] at 50 m, mph
2	Marginal	200–300	5.6–6.4	12.5–14.3
3	Fair	300–400	6.4–7.0	14.315.7
4	Good	400–500	7.0–7.5	15.716.8
5	Excellent	500–600	7.5–8.0	16.8–17.9
6	Outstanding	600–800	8.0–8.8	17.9–19.7
7	Superb	800–1600	8.8–11.1	19.7–24.8

In addition to the wind resource, factors such as terrain, land use, proximity to electricity transmission lines, and economic incentives should be taken into account in the determination of developable land. Terrain characteristics important to wind developers include land classification and slope. More specifically, land classified as lakes or other large bodies of water, erodible land, and flood plains are not ideal locations for wind turbines. Additionally, wind turbines cannot be built on steep slopes such as those found on the sides of mountains or bluffs.

Land use is also an important consideration. Obviously, wind farms are not likely to be constructed in population centers; state, provincial, and federal parks; or wildlife preserves. Proximity to power lines may be important if a wind energy project is built a significant distance away from the source of demand. Finally, economic incentives vary across political boundaries and depend on demand. All of these factors are geographically dependent. With the use of GIS software, they can be combined with the wind resource maps to identify areas that are suitable for development.

For the PCOR Partnership example, areas collocated with lakes or other large water bodies were removed from consideration. Federal-, state-, or province-protected lands, with the exception of Native American and Bureau of Land Management public domain lands, were also eliminated from potentially developable land. Other than the removal of mountainous regions, terrain (specifically slope) was not analyzed by this study. Terrain plays a more important role in local-scale analyses. Proximity to electrical transmission, another factor that would be analyzed on a local scale, was not evaluated in this example study either.

Economic incentives were indirectly taken into account. Information gathered on the locations of existing and future wind farms was used to identify wind classes where wind energy development is potentially economical. Table 5 summarizes by state and province the minimal wind resource where existing wind farms or prospective wind energy developments are currently found.

Table 5. Minimum Wind Resource Class for Each State or Province Deemed Sufficient for Potential Wind Energy Development

Government Entity	Wind Resource Class
Alberta	2+[a]
Iowa	4
Manitoba	2+
Minnesota	4
Missouri	2
Montana	4
Nebraska	4
North Dakota	4
Saskatchewan	2+
South Dakota	4
Wisconsin	2
Wyoming	4

[a] "+" indicates the upper half of the class.

The application of these parameters to the wind resource maps for the PCOR Partnership region resulted in the orange-shaded areas shown in Figure 1. A comparison of wind resource to CO_2 sources and areas of coal and oil reserves suggests that the following areas might be favorable for the development of wind power for geological sequestration projects: southern Alberta, southwestern Saskatchewan, eastern Montana, western North Dakota, northeastern Wyoming, and northern Missouri. Figures C1–C3 in Appendix C provide a closer look at these regions.

The annual energy demand of the compressors or pumps for which wind energy will be used is determined from the load requirement and annual electricity usage. The total number of wind turbines required can be derived from the power rating of the wind turbines to be installed.

CARBON-TRADING SYSTEMS

The Kyoto Protocol established emission limits for each nation that ratified the agreement. The limits were determined by taking into account population, potential economic growth, and past emission history. Each national government is responsible for allocating emission allowances to industries, businesses, and consumers within its political boundaries. Individuals, companies, or governments that reduce emissions below allowances through the use of renewable energy, energy efficiency, improved land use, etc., could earn credits that would be tradable with other entities, including other nations.

A global carbon-trading system has not yet been established, although Europe and North America have established carbon-trading programs. The European Union Emissions Trading Scheme (EUETS) establishes a system for greenhouse gas emission allowance trading with member countries of the European Union (Lloyd's Register Quality Assurance, 2007). The Chicago Climate Exchange (CCX®) is a self-regulatory, rules-based trading system for North America (Chicago Climate Exchange, 2007a). CCX members join voluntarily but agree to make legally binding commitments to reduce greenhouse gas emissions through various mostly agriculture-based activities. Eligible activities include adopting continuous no-till, strip-till, or ridge-till cropping practices; grass planting; tree planting; and reduction of emissions resulting from agricultural methane collection or combustion systems. Carbon credits are issued based on storage quantification protocols developed by CCX.

Other North American programs include the Voluntary Reporting of Greenhouse Gases 1605 (b) Program (Energy Information Administration, 2007f), the Regional Greenhouse Gas Initiative (RGGI) (Pew Center for Global Climate Change, 2007), and the California Climate Action Registry (California Climate Action Registry, 2007).

In the trading programs, members must agree to reduce the amount of greenhouse gases, including CO_2 that are released into the atmosphere. Members are given allowances or credits, which represent the right to emit a specific amount. Companies that produce more than their allowance must buy credits from other members, resulting in a market that, in effect, fines the buyer for polluting, while rewarding the seller for reducing emissions.

Carbon credits may be referred to as certified emission reductions (CERs). Each CER is equivalent to 1.1 short tons of CO_2 reduction (Foundation for International Environmental Law and Development, 2007). Market forces drive the price of the CERs. For example, if more firms need to buy CERs, the price is higher, making emission reduction cost-effective in comparison. CERs can also be purchased by nonindustrial entities that see an investment opportunity or simply want to increase demand in order to provide additional incentive for CO_2 reduction.

VALUE OF CARBON CREDITS TO WIND ENERGY

In determining the cost of wind energy, the economic impact of carbon credits to wind energy projects should also be considered. Their impact depends on their quantity and price. The fossil fuel being offset is the determining factor for the number of carbon credits earned by a wind energy project. As shown in Table 3, the various fossil fuels produce different CO_2 emissions for every MWh of electricity generated. This quantity of CO_2 is the amount that can be offset by carbon credits. Although carbon credits are calculated on a "per metric ton" basis, carbon credit equivalents in this report were determined on a "per short ton" basis to maintain consistency throughout the report and with other PCOR Partnership documents. Table 6 shows the potential carbon credits for various fuel types.

Table 6. Carbon Credit Obtained for Offsetting CO_2 Emissions from Coal, Fuel Oils, Natural Gas, and Petroleum Coke

Fossil Fuel	Carbon Credit, short tons/MWh
Distillate Fuel Oil	1.01
Petroleum Coke	1.15
Residual Fuel Oil	0.88
Natural Gas	0.57
Coal (weighted mean)	1.05
Anthracite and Bituminous Coal	1.00
Lignite	1.22
Subbituminous Coal	1.11

As with any commodity, carbon credit prices will vary over time. For example, between the CCX inception in December 2003 and October 2007, the value of a carbon credit has varied between \$0.64 and \$4.54/ton (Chicago Climate Exchange, 2007b). End-of-year closing has been about \$4.05/ton for several years. In Europe, where participation in carbon trading is mandatory for certain industries, carbon credit prices are significantly higher, at one point in April 2006 reaching \$35.89/ton of CO_2 (European Climate Exchange, 2007).

Figure 2 paints an overall picture of the economic impact carbon credits have on the price of wind energy. The price range for carbon credits is assumed to be between \$0 and \$18 per

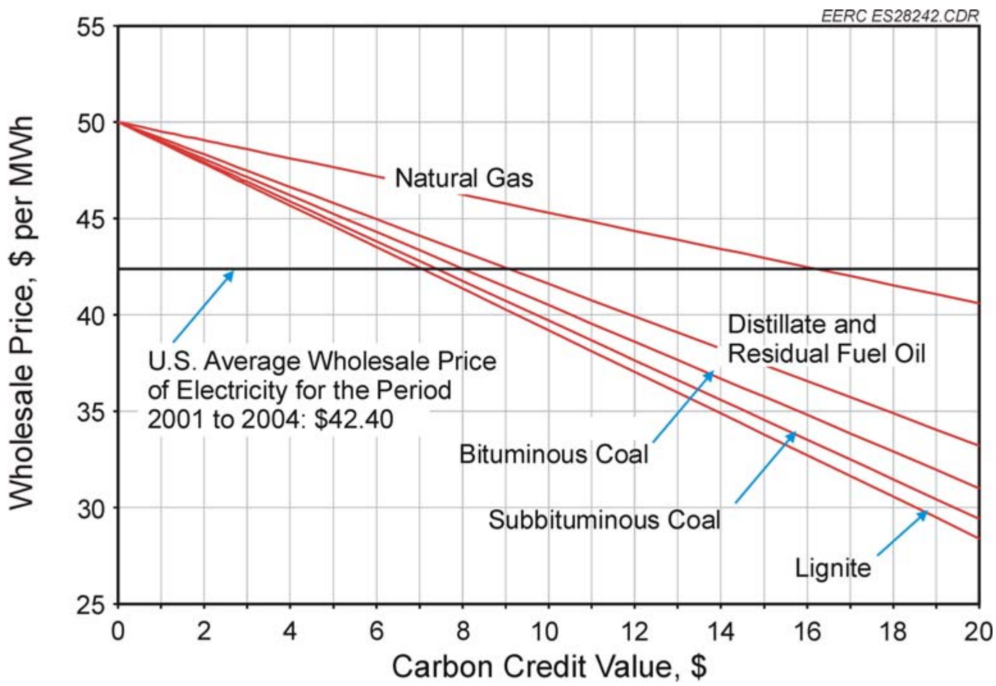

Figure 2. The benefit of carbon credits to wind energy is dependent upon the fossil fuel and the value of the credits. The national average cost of wind energy without a production tax credit (PTC) is estimated to be $50 per MWh.

short ton of CO_2, the range that brackets current high and low price ranges. Each line represents the displacement of a particular fossil fuel by wind energy. The slope of a line represents the value of the carbon offset for that particular fossil fuel. For example, the displacement of power from lignite results in 1.11 carbon credits per MWh of electricity. In the absence of carbon credits, all scenarios converge to the American Wind Energy Association's estimated national average wholesale price of wind energy with the federal PTC, or $0.05/kWh, or $50/MWh (American Wind Energy Association, 2007). Other wind power price estimates for projects built in 2006 range from $30/MWh to $64/MWh with the federal PTC (Wiser and Bolinger, 2007).

The federal production tax credit is a tax credit for electricity that is generated by specific renewable energy resources. It currently stands at $0.02/kWh ($20/MWh) (North Carolina Solar Center, 2007). If the average wholesale price of wind energy is $50/MWh, the PTC can drop this price to $30/MWh. Likewise, if the wholesale price is $85/MWh, the PTC can drop the price to $65/MWh.

If carbon credits are worth $7 each, the added value to 1 MWh of wind electricity is $7.77, which decreases the wholesale price of wind energy from a range of $50/MWh to $85/MWh to $42.23/MWh to $77.23/MWh, respectively. The average wholesale price of electricity in the United States in 2005 was $50.50 (Energy Information Administration, 2007g). Obviously, incentives such as a PTC and/or carbon credits are necessary for wind energy to compete with existing conventional power sources.

Because coal is used to produce a significant fraction of the electricity in the United States and it has one of the higher emission rates of CO_2 for fossil fuels, wind energy may more often be used to offset emissions from coal power plants. Figure 2 shows that, for a wholesale price of electricity of \$42.40/MWh, wind energy projects will be competitive on the wholesale market without federal tax credits for carbon credit prices between \$7 and \$8/ton. This is an encouraging result considering that the carbon credit value has reached as high as \$4.54 per short ton in North America's voluntary market (during the third quarter of 2006).

The method of generation impacts CO_2 credits in a way that is not illustrated in Figure 2. Figures B1–B3 in Appendix B show the impact that the generation method (e.g., combined-cycle turbine versus steam turbine) has on the carbon offset value for distillate fuel oil, residual fuel oil, and natural gas, respectively. Thus both the buyer and seller of carbon credits should be aware of the source of CO_2 and method of production.

A similar comparison was not performed for coal because all of the coal power plants listed by EIA utilize steam turbines. Although the generation method does have an impact, the dominant factor in the determination of CO_2 emissions is the choice of fossil fuel.

SUMMARY AND CONCLUSIONS

Renewable energy, such as wind, can be used to reduce the emission of CO_2 to the atmosphere or allow a facility to increase power generation while maintaining current emission levels. The applicability of using wind resources to offset some of the fossil fuel-generated electricity needed for CO_2 geologic sequestration activities can be estimated using the methodology outlined in this document.

The quantity of CO_2 offset (i.e., the emissions reduced) required from wind energy depends on the fossil fuel and type of power plant. CO_2 emissions can be calculated for several types of fossil fuel power plants. The results indicate that fossil fuel type has a greater impact on emission than the method of generation. Petroleum coke and lignite produce the most CO_2, while natural gas has the lowest emission rate.

A case study investigating the use of wind energy to replace lignite-produced electricity for CO_2 compression estimated an economically viable revenue of \$3.2 million annually and a 13-yr simple payback. Eighteen 1.5-MW wind turbines are required to match the 27-MW demand of the compressors for a CO_2 pipeline located in western North Dakota. The capital investment is \$40.5 million. Utilization of wind energy in this case study would generate 86,400 short tons of carbon credits and a potential revenue of \$350,000 annually from carbon credits. However, the PTC and electricity savings have a greater impact on economic viability, representing 92% of the estimated revenue.

It seems increasingly likely that some type of incentives or penalties will be put in place to encourage carbon management. CCX, a carbon-trading market, exists for North America, but participation is voluntary. Carbon credit prices on the CCX for the third quarter of 2006 hovered around \$4.54 per short ton. Preliminary calculations indicate that the cost of unsubsidized wind energy approaches wholesale market prices (based on prices from 2001 to 2004) when carbon credit prices reach $7 to $8/ton and the energy is used to offset emissions from coal power plants. In summary, these credits could help alleviate federal subsidies currently in place to encourage renewable energy development.

REFERENCES

American Wind Energy Association, 2007, www.awea.org/faq/wwt_costs.html (accessed October 2007).

California Climate Action Registry, 2007, www.climateregistry.org/ABOUTUS/ (accessed October 2007).

Canadian Wind Energy Atlas, 2007, www.windatlas.ca/en/index.php (accessed October 2007).

Chicago Climate Exchange, 2007a, www.chicagoclimatex.com/ (accessed October 2007).

Chicago Climate Exchange, 2007b, www.chicagoclimatex.com/trading/stats/daily/index.html (accessed October 2007).

Chikatamarla, L., and Bustin, M.R., 2003, Sequestration potential of acid gases in western Canadian coals: 2003 International Coalbed Methane Symposium, University of Alabama, Tuscaloosa, Alabama, May 5–8, 2003, Proceedings: p. 16.

Energy & Environmental Research Center, 2007, www.undeerc.org/wind (accessed October 2007).

Energy Information Administration, 2007a, www.eia.doe.gov/cneaf/electricity/epa/figes1.html (accessed October 2007).

Energy Information Administration, 2007b, www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html (accessed October 2007).

Energy Information Administration, 2007c, www.eiq.doe.gov/oiaf/1605/coefficients.html (accessed October 2007)

Energy Information Administration, 2007d, www.eia.doe.gov/cneaf/electricity/page/eia860.html (accessed October 2007).

Energy Information Administration, 2007e, http://tonto.eia.doe.gov/FTPROOT/electricity/034806.pdf (accessed October 2007).

Energy Information Administration, 2007f, www.eia.doe.gov/oiaf/1605/policy.html (accessed October 2007)

Energy Information Administration, 2007g, www.eia.doe.gov/cneaf/electricity/wholesalet2.xls (accessed October 2007).

European Climate Exchange, 2007, www.europeanclimateexchange.com/default_flash.php (accessed October 2007).

Foundation for International Environmental Law and Development, 2007, www.cdmguide.net/glossary.html#ii (accessed October 2007).

Lloyd's Register Quality Assurance, 2007, www.lrqa.co.uk/productsandservices/environment/euets (accessed October 2007).

Nelson, C.R., Steadman, E.N., and Harju, J.A., 2005, Geologic CO_2 sequestration potential of the Wyodak–Anderson coal zone in the Powder River Basin: Draft Plains CO_2 Reduction (PCOR) Partnership topical report for U.S. Department of Energy and multiclients, Grand Forks, North Dakota, Energy & Environmental Research Center.

North Carolina Solar Center and the Interstate Renewable Energy Council, 2007, www.dsireusa.org/library/includes/incentive2.cfm?Incentive_code=US13F&State=federal&currentpageid=1&ee=1&re=1 (accessed October 2007).

Pew Center for Global Climate Change, 2007, www.pewclimate.org/what_s_being_done/in_the_states/rggi (accessed October 2007).

U.S. Department of State, 1998, The Kyoto Protocol on Climate Change, Fact Sheet. http://usinfo.state.gov/usa/infousa/laws/treaties/fact0198.htm (accessed October 2007)

Wiser, R.; Bolinger, M. Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006: DOE/GO–102007–2433; U.S. Department of Energy Office of Energy Efficiency and Renewable Energy: Washington, D.C., 2007.

PCO2R Partnership

For more information on this topic, contact:

Edward N. Steadman, EERC Senior Research Advisor
(701) 777-5279; esteadman@undeerc.org

John A. Harju, EERC Associate Director for Research
(701) 777-5157; jharju@undeerc.org

Visit the PCOR Partnership Web site at www.undeerc.org/PCOR.

Sponsored in Part by the U.S. Department of Energy

NETL

APPENDIX A

UTILIZING WIND POWER TO REDUCE THE CO_2 FOOTPRINT OF COMPRESSORS AT THE DGC GREAT PLAINS SYNFUELS PLANT

UTILIZING WIND POWER TO REDUCE THE CO_2 FOOTPRINT OF COMPRESSORS AT THE DGC GREAT PLAINS SYNFUELS PLANT

INTRODUCTION

The Energy & Environmental Research Center (EERC) investigated the use of wind power to provide energy for CO_2 compression at the Dakota Gasification Company (DGC) Great Plains Synfuels Plant. Fossil fuels are currently used to meet the energy demands of the compressors, resulting in CO_2 emissions. These emissions lower the net amount of CO_2 captured and compressed at the plant. The concept outlined here is to utilize wind energy near DGC for compressor operation, displacing the fossil fuels used. The incentive is to maximize the potential for carbon credits and to minimize the potential CO_2 emission penalties.

CONCEPT DESCRIPTION

This study investigated the potential for a locally developed wind energy facility (i.e., wind farm) to supply the power required to compress CO_2 at the DGC plant. The plant is located in North Dakota, a state with abundant wind energy potential. Wind energy is a renewable resource which could be used to reduce CO_2 emissions attributed to compressor operation. Because wind is an intermittent source of energy, it is assumed that coal-generated electricity from Basin Electric Power Cooperative (BEPC) will supplement the electricity from the wind farm.

The DGC plant utilizes compressors that each have a load requirement of 27 MW and an estimated annual usage of 223,000 MWh (Perry and Eliason, 2004). Each compressor houses a 19,500-hp motor. The compressors run continuously and have an availability of 94%, operating about 8260 hr/yr. They are rated at 55 mmscf CO_2 per day, or 130 short tons/hr each. The compressors process approximately 1.9 million short tons CO_2 per year.

The electricity currently consumed by two of these compressors contributes to the release of 272,000 short tons of CO_2 annually, or 13% of the total annual CO_2 compressed. BEPC currently supplies electricity to DGC for compressor operation via a lignite-fired power plant. Electricity produced from lignite, also abundantly available in North Dakota, is estimated to release 1.22 short tons CO_2 per MWh electricity produced (shown in Table 3 of the best practices manual to which this document is an appendix; calculated using information from Energy Information Administration, 2007a, b).

WIND RESOURCE ASSESSMENT

Site Data Analysis

The best method to estimate project performance is to collect wind data at the site. Because wind resources have not been monitored at the DGC facility, the National Renewable Energy Laboratory's (NREL's) wind resource map for North Dakota (Energy Efficiency and Renewable

Energy, 2007) and wind data from tall tower sites in the region were used to estimate the performance of a GE 1.5s utility-scale wind turbine near the DGC facility. The GE 1.5s wind turbine has a nameplate production capacity of 1500 kW (1.5 MW), and it was selected because it is currently the most widely installed utility-scale wind turbine in the United States (GE Energy, 2006).

Based on this distribution and a hub height of 213 feet, a GE 1.5s wind turbine can be expected to produce between 3880 and 4710 MWh electricity per year if placed in close proximity to the DGC facility. The NREL wind resource map, Figure A-1, indicates that the DGC plant is located in an area with Class 3 winds at 164 ft, corresponding to average annual wind speeds of 14.3–15.7 mph (see Figure 2 of the report). A Weibull distribution with a shape factor of 2.0 is assumed for the wind speed frequency distribution. The hub height was selected based on current general knowledge of installation heights for today's utility-scale wind turbines.

In an attempt to refine the wind speed estimate, analyses were performed on wind data collected at nearby monitoring sites. According to the Plains Organization for Wind Energy Resources® (POWER®) database, wind-monitoring data are available for eight sites within a 60-mile radius of the DGC facility. Three sites were the Killdeer, Green River, and Wilton sites. Their locations are shown in Figure A-1. These sites had three or more monitoring heights, with a maximum height of 131 or 165 feet. For comparison purposes, energy production analyses were based on the data sets from a height of 131 feet.

The five remaining sites were not analyzed because of incomplete or incomparable data. Three of these sites have only one monitoring height at 66 feet. Because these sites have only one sensor at one height, it is difficult to evaluate the data quality. Consequently, these sites were removed from consideration. Only 11 months of data had been collected at a fourth site, so it was eliminated as well. A fifth site was eliminated because of its unique topographical location: the Missouri Escarpment, a prominent ridge along the north and east side of the Missouri River. Because the DGC plant is not located near this escarpment, the site likely experiences significantly different wind characteristics.

Each data set was examined for data gaps and data quality. For example, the Killdeer tower experienced an icing event beginning the evening of April 27. During a 12-hour period, icing on the sensor at 131 feet prevented an accurate wind measurement. A lower sensor at 33 feet, however, did not appear to be affected by ice. Therefore, data from the 33-ft sensor were extrapolated to 131 ft to provide a more accurate representation of wind speeds. For reasons of data quality and to facilitate annual energy calculations, data sets were narrowed to 1 year (8760 hours) of data. The year selected for each site, shown in Table A-1, had the fewest data gaps and the best quality of data compared to other years. Time intervals of an hour were included in all three data sets.

WindPRO was used to generate energy production statistics for the GE 1.5s wind turbine at a hub height of 213 feet. WindPRO is industry-accepted software used to design and plan both single wind turbines and wind turbine farms. A summary of results from WindPRO is presented in Table A-2. A 1.5 MW turbine is predicted to produce more than 4000 MWh of electricity at

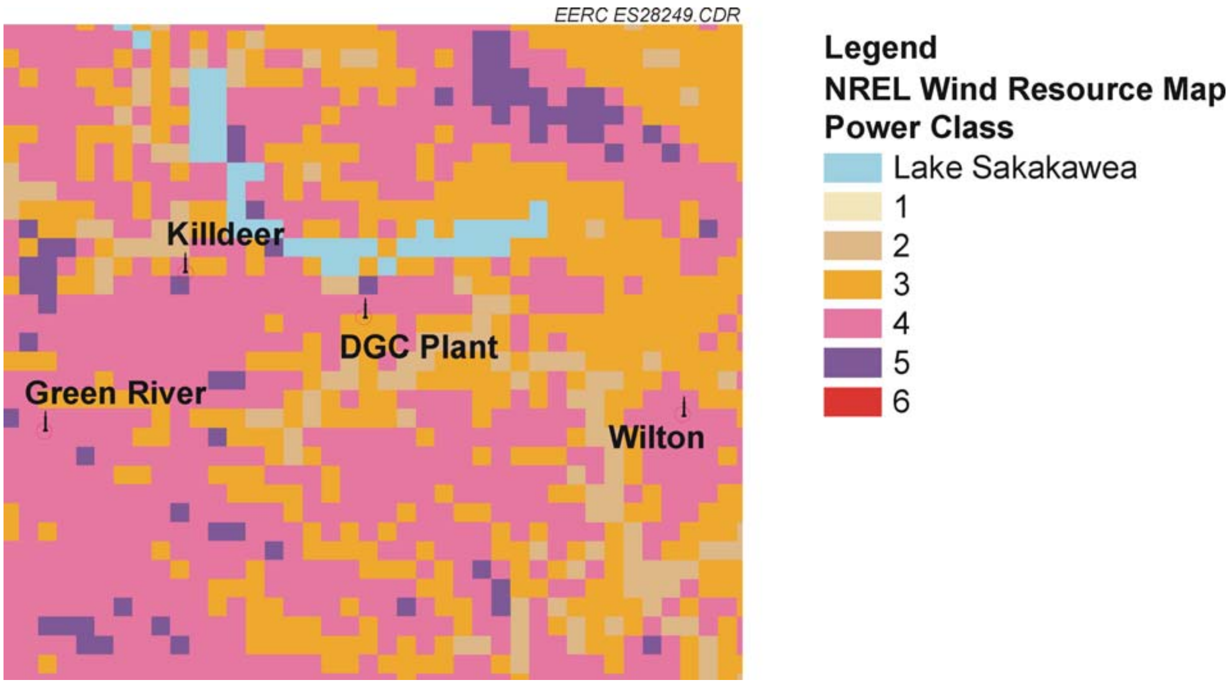

Figure A-1. Wind resource map of the region around the DGC facility.

Table A-1. Year of Data Analyzed for Monitoring Sites

Site	Year
Green River	1996
Killdeer	2002
Wilton	1996

Table A-2. Results from WindPRO Analyses of 1 Year of Quality-Controlled Data*

Site Name	Production	Turbine Capacity
Green River	4031 MWh	31%
Killdeer	4622 MWh	35%
Wilton	4706 MWh	36%

* Statistics account for a 10% deduction. The deduction is an estimate of potential error due to measurement uncertainties and losses due to turbine availability, transmission, control system, etc.

all three sites. An examination of wind power densities indicates that the Green River site has a high Class 3 wind resource, while Killdeer and Wilton have low-to-mid Class 4 resources, respectively. Although these data contradict the classes shown for each site in Figure A-1 (e.g., Killdeer–Class 5, Green River–Class 4), the map does provide useful information regarding the relative change of the wind resource across the landscape. Turbine capacity factors did not drop below 30% for any of the sites, suggesting a good wind resource for utility-scale wind turbines.

Long-Term Data Extrapolation

The data from Green River, Killdeer, and Wilton were compared to data from the Bismarck Municipal Airport (BMA) and modified to approximate long-term site conditions. The results presented in Table A-2 are valid only for the data collection year in question, and a long-term assessment of the wind resource is needed for accurate estimation of wind energy potential. Because a long-term reference site with average hourly wind speeds could not be identified, a long-term reference of average daily wind speeds was used. BMA was identified as the nearest reference site.

Table A-3 presents the average annual wind speed for the airport calculated from the daily values for years 1985 to 2005. The daily average wind speeds for the airport were obtained from the National Climatic Data Center. Wind speeds were measured at a height of 30 ft aboveground. It should be noted that the annual average wind speed for 1996 (Green River and Wilton

Table A-3. Average Wind Speed for Each Year Between 1985 and 2005

Year	Annual Wind Speed, mph
1985	10.34
1986	9.49
1987	9.25
1988	10.26
1989	10.01
1990	9.83
1991	10.28
1992	9.34
1993	9.94
1994	10.37
1995	10.17
1996	9.74
1997	9.51
1998	8.57
1999	9.40
2000	9.23
2001	8.84
2002	9.39
2003	9.30
2004	9.62
2005	9.62
Overall Average	9.64

data year) is greater than the overall average over 21 years, while the year of 2002 (Killdeer data year) is below the average.

A long-term average and standard deviation were also computed for each month using the average daily values, shown in Table A-4. Average wind speeds for each month in 1996 and 2002 were compared to the calculated long-term averages by means of standardized anomalies. A standardized anomaly provides a nonbiased measure of the departure from normal, and it is a nondimensional value that removes the influences of location and spread from the data. It was thus assumed that departures from the long-term monthly normal values would be similar between BMA and the three wind-monitoring sites and that these departures are independent of height. For example, if the mean wind speed for March 1996 at BMA was 10% below normal, then the mean wind speeds for 10, 25, and 40 meters at Green River were also assumed to be below normal by 10%.

Standardized anomalies computed for each month in 1996 and 2002 at BMA were applied to the data from each wind-monitoring site accordingly. The use of standardized anomalies eliminated comparison errors resulting from differences in the magnitude and spread of wind speed data between the monitoring sites and BMA. The monthly average wind speeds and standard deviations for the monitoring sites along with the standardized anomalies by month were used to back-calculate long-term monthly average wind speeds for each site.

It is important to note that values of monthly average standard deviations should represent the long-term average when performing this back-calculation. Because a long-term data set was not available for each site, the monthly average standard deviations were instead computed from the current data set (i.e., 1996 or 2002). Although this introduces error into the estimate of the long-term monthly average wind speeds, the error should be relatively small. Several reasons exist for this assumption. First, the change in standard deviation between months is typically 0.1 to 0.5 mph, as shown in Table A-4. This variability between months should be larger than the year-to-year variability because of the seasonal effect. The second reason is that the variability in

Table A-4. Standard Deviation of Hourly Wind Speed Averaged over Each Month at the Wilton Site

Month	Standard Deviation of Wind Speed, mps
January	7.25
February	7.72
March	7.67
April	8.10
May	6.53
June	6.64
July	6.44
August	6.73
September	6.82
October	7.47
November	7.20
December	9.35

average monthly wind speed from year to year is small. For example, average wind speeds for all months of January from 1985 to 2005 are within 1.81 mph. Hence, the annual variability in the monthly averages of hourly standard deviations should be small as well.

The average hourly wind speed data for each site were adjusted to reproduce the back-calculated long-term average monthly wind speeds, which then were imported into WindPRO for energy analysis. The results are summarized in Table A-5; again, turbine capacity factors did not drop below 30% for any of the sites, suggesting a good wind resource for utility-scale wind turbines. The long-term estimation of wind power density indicates that Green River has a Class 3 wind resource, while both Wilton and Killdeer have Class 4 wind resources. Based on Figure A-1, the area surrounding the DGC facility has a Class 3 wind resource. Therefore, the Green River site is expected to provide an accurate representation of wind energy production near the DGC facility.

Table A-5. Energy Production Estimates from WindPRO Analysis of Quality-Controlled Data Representing Climate Conditions*

Site Name	Production	Turbine Capacity
Green River	3933 MWh	30%
Killdeer	4769 MWh	36%
Wilton	4623 MWh	35%

* Statistics account for a 10% deduction. The deduction is an estimate of potential error due to measurement uncertainties and losses due to turbine availability, transmission, control system, etc.

ECONOMICS

Because of the intermittency of wind, two approaches are available for utilization of wind energy to supply power to the compressors: match of energy requirement or match of power requirement. Two of the compressors currently in operation at DGC have a load requirement of 27 MW and annual usage of approximately 223,000 MWh. The annual energy required by the two compressors could be met with the installation of 57 GE 1.5s (1.5 MW) wind turbines on location to generate 223,000 MWh/yr. At capacity, the wind turbines would produce 86 MW of electricity. Another option is to match the wind power output to meet the 27 MW demand of the compressors, requiring eighteen 1.5-MW wind turbines for the project. The average generation (i.e., long-term estimate) over the course of a year for this wind farm is approximately 70,800 MWh.

The capital investment for each scenario is $40.5 million and $128 million for the power and energy approaches, respectively. The rule of thumb for the installed cost of a GE 1.5s wind turbine is $1500/kW (personnel communication, 2007), or $1.5 million per MW per turbine. An assumed service life of 20 years is used. Interest is estimated to cost $1.5 and $4.8 million annually for each respective scenario, assuming a 6% loan.

The potential revenue from carbon credits is \$350,000 annually for the power approach or \$1.1 million a year for the energy approach. Electricity from a lignite-fired plant generates 1.22 short tons of CO_2 per MWh; the current compression electricity needs generate 272,000 short tons CO_2 per year. Utilization of wind energy for all or a portion of the compression would generate 86,400 short tons or 272,000 short tons of carbon credits annually for the power and energy scenarios, respectively. Calculations are based on an average carbon credit value of \$4.05 per short ton of CO_2 (Chicago Climate Exchange, 2007).

Other incomes or savings to consider include the production tax credit (PTC) and electricity savings from utilizing wind energy, amounting to \$4.3 million for the power scenario and \$14 million for the energy scenario. The federal PTC is for electricity generated by specific renewable energy resources, such as wind, and currently stands at 1.9¢/kWh, or \$19/MWh (North Carolina Solar Center, 2007). The average wholesale price of \$42.40/MWh for electricity given in the best practices manual was used for calculations. The PTC income is estimated to be \$1.3 million and \$4.2 million a year, respectively, and the electricity savings is about \$3.0 million and \$9.5 million a year, respectively.

The economics of each scenario are summarized in Table A-6, showing estimated revenues of \$3.2 million annually for the power approach and \$10 million annually for the energy approach, as well as a 13-yr simple payback for both scenarios. Although the energy scenario has the potential to generate the most revenue, more than 3 times the demand of the two compressors would be produced. For the energy to be available at a constant rate to the compressors, this approach would require a storage device, increasing capital as well as higher energy output to compensate for recovery losses or selling the power generated to BEPC as a form of storage, which may require considerable negotiations for carbon and PTCs, lowering potential revenue. Therefore, the power approach is recommended as the most economical solution for utilization of wind energy for CO_2 sequestration.

Table A-6. Wind Energy CO_2 Sequestration Economics

	Power Approach	Energy Approach[a]
Quantity, turbines	18	57
Power, MW	27	86
Energy, MWh	70,800	223,000
Carbon Credits	86,400	272,000
Capital	\$40,500,000	\$128,000,000
<u>Revenue</u>	<u>\$3,190,000</u>	<u>\$10,000,000</u>
Interest Payment (6%, 20-yr)	−\$1,510,000	−\$4,770,000
Annual Credit Increase	\$350,000	\$1,100,000
Electricity Savings/Income	\$3,000,000	\$9,450,000
Production Tax Credit	\$1,350,000	\$4,240,000
Payback, yr	13	13

[a] Requires storage, selling power to BEPC, and/or credit negotiations.

REFERENCES

Chicago Climate Exchange, 2007, www.chicagoclimatex.com/trading/stats/daily/index.html (accessed October 2007)

Energy Efficiency and Renewable Energy, 2007, www.eere.energy.gov/windandhydro/wind poweringamerica/maps_template.asp?stateab=nd (accessed October 2007).

Energy Information Administration, 2007a, www.eia.doe.gov/cneaf/electricity/page/eia906_ 920.html (accessed October 2007).

Energy Information Administration, 2007b, www.eia.doe.gov/oiaf/1605/coefficients.html (acessed October 2007)

GE Energy, 2007, www.gepower.com/prod_ser/products/wind_turbines/en/15MW/index.html (accessed October 2007).

North Carolina Solar Center and the Interstate Renewable Energy Council, 2007, www.dsircusa.org/library/includes/incentive2.cfm?Incentive_code=US13F&State=federal &currentpageid=1&ee=1&re=1 (accessed October 2007).

Perry, M., and Eliason, D. CO_2 recovery and sequestration at Dakota Gasification Company: Presented at 19th International Conference on Lignite, Brown, and Subbituminous Coals, Billings, Montana, October 2004.

Personnel communication, Brad Stevens to Melanie Jensen, Energy & Environmental Research Center, January 9, 2007.