

Citation:

J. DeCarolis and D.W. Keith. *Is the Answer to Climate Change Blowing in the Wind?* Proceedings of the first International Doctoral Consortium on Technology, Policy, and Management. E. F. ten Heuvelhof, ed. Delft, The Netherlands, Delft University (17-18 June 2002) p. 199-215. ISBN: 90-5638-094-x.

Is the Answer to Climate Change Mitigation Blowing in the Wind?

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Abstract

The use of fossil fuels to produce electricity generates significant environmental impacts, and has led to an intense interest in a cleaner and more affordable electricity supply. Electricity from wind power provides an alternative to conventional generation that can yield significant reductions in carbon dioxide emissions and fossil fuel use. Discussions of large-scale wind must address the problems posed by the spatial distribution and intermittency of the wind resource. The greenfield analysis presented in this paper provides a first-order economic characterization of wind in a baseload system in which long-distance electricity transmission, storage, and backup gas capacity are used to supplement the variable wind power output to meet a fixed load. The utilization of wind to help meet a fixed load simplifies the analysis and provides a useful proxy for a model that incorporates the complex supply and demand dynamics that characterize electricity markets. The results of this preliminary model indicate that baseload wind is capable of effecting deep cuts in carbon emissions at a cost competitive with other zero emissions energy technologies such as nuclear or coal with carbon capture.

Keywords: wind, baseload, optimization

1. Introduction

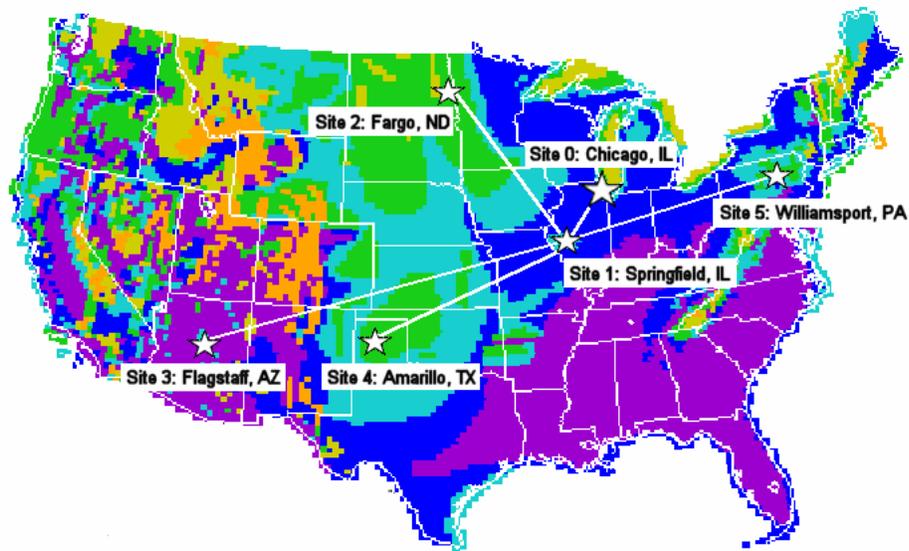
The use of fossil fuels to produce electricity has generated significant environmental impacts, and has led to an intense interest in a cleaner and more affordable electricity supply in both the United States and abroad. In addition, the electricity sector will likely bear the brunt of future greenhouse gas reductions to mitigate climate change since electric power plants are among the largest and most manageable point sources of CO₂. Wind energy has both the economic and technological potential to serve a large proportion of electricity demand in a carbon-constrained regulatory environment and is capable of effecting deep reductions in emissions.

1.2 Cost of Wind

Wind is among the most cost-competitive renewables, comparable to biomass and an order of magnitude cheaper than photovoltaics (Cassedy and Grossman, 1998). The generation cost of wind has decreased from about 40 ¢/kWh in the early 1980s to 4 ¢/kWh today in areas with good wind resources. The lowest unsubsidized generation cost from wind in the best wind class 6 sites is 4 ¢/kWh (Robinson, 2001). These generation costs combined with the 1.5 ¢/kWh federal credit for wind energy producers currently make wind competitive with

conventional fossil sources in many areas. The goal of the National Renewable Energy Laboratory (NREL) is to reduce the cost of wind to 3¢/kWh in wind class 4 sites by 2007 (Parsons, 2001). Advances in turbine strength and aerodynamics, variable speed generators, and electronic power controls coupled with taller towers to access strong winds may reduce the cost of wind to 2¢/kWh in the near future (Bull, 2001). In addition, wind turbine mass production has and will continue to reduce the capital cost at which manufacturers sell their turbines. Already, in deals with Florida Power and Light, the Danish turbine manufacturer Vestas is rumored to be selling turbines alone for \$400 / kW, resulting in a greenfield cost of \$600 / kW (Parsons, 2001).

The overall cost-effectiveness of a wind farm depends not only on the incurred capital costs, but also by the characteristics of wind at a particular site. The wind map of the U.S. presented below has been translated into average wind energy generation cost by taking into account the capital cost, fixed and variable operation and maintenance (O&M) costs, and the capacity factor. The capacity factor represents the percent of a year that a turbine would have to run at its rated output to produce its annual output (McGowan, 2000). Wind power exhibits a cubic dependency on wind speed, making turbine performance very sensitive to location. According to Figure 1, increasing the average wind speed by roughly 40 percent yields a fourfold decrease in the average cost of generation.



Power Class	Wind Power (W/m ²)	Speed (m/s)	Capacity Factor	Average Cost
1	<200	<5.6	10%	\$0.204
2	200-300	5.6-6.4	18%	\$0.113
3	300-400	6.4-7.0	24%	\$0.085
4	400-500	7.0-7.5	28%	\$0.073
5	500-600	7.5-8.0	32%	\$0.064
6	600-800	8.0-8.8	38%	\$0.054
7	>800	>8.8	45%	\$0.045

Figure 1. Map of US wind potential (NREL, 2000). The table above translates the wind class into an average cost by taking into account capital costs, fixed and variable O&M costs, and the capacity factor. The average cost was estimated by amortizing the capital cost over the 20-year lifetime of the turbine at a 10 percent discount rate and adding it to the annual fixed and variable O&M costs. This total annual cost is divided by the product of

the number of hours in a year (8766) and the capacity factor. The assumed capital cost was \$800 / kW, variable O&M was \$8 / MWh, and the fixed O&M was \$15 / kW-yr (McGowan, 2000). In addition, the capacity factors were estimated from a plot of annual generation for a Vestas 600 kW machine (McGowan, 2000). The map also shows the geometric configuration of wind sites used in the optimization model presented in Section 2. Sites were selected for sufficient geographic diversity to span synoptic scale weather patterns. Chicago, IL is the demand center being served.

If the current generation costs for wind-generated electricity are scale-invariant, such that a significant fraction of the U.S. electricity demand can be met at 4 ¢/kWh, wind appears to be a cheap, clean alternative to conventional fossil sources. As such, wind should dominate new electricity capacity installations under even a moderate constraint on CO₂ emissions. But the spatial distribution and intermittency of wind resources must be addressed for large-scale applications and raise the real cost of large-scale wind.

1.3 Intermittency

Wind resources are intermittent, meaning that the power extracted from the wind depends on whether, when, and how hard the wind blows. Under future climate regulation, large wind farms on the order of 1 – 10 GW producing highly variable power output would require more backup capacity. For small wind farms currently in operation, system operators utilize existing contingency reserves, quick-start units, and slow-start units to compensate for periods of low wind turbine power output. Contingency reserves are online generating units capable of producing electricity but not providing current to the grid (Milligan, 2000). The reliability requirements for contingency reserves are based on either maximum peak daily load or the largest single contingency. Since most current wind farms do not exceed 500 MW and the largest contingency due to a large fossil or nuclear plant is typically 1 GW, small wind turbine arrays do not contribute to the need for these reserves (Hirst, 2001). Quick-start units consisting of combustion turbines with lead times measured in minutes, while slow-start units such as coal or nuclear have lead times that span hours or days (Milligan, 2000). Unit commitment is the process of dispatching slow-start units, requiring hours or days to be brought on-line, in order to meet demand and relies on accurate forecasts of daily supply and demand.

Because current wind farm capacities are small relative to overall generation capability within a particular control area, system operators can treat wind energy as a negative load and compensate unpredictable wind power output by using standard load-following control procedures (Richardson and McNerney, 1993). But as wind farms increase in size relative to the control area, the amplitude of power fluctuations from intermittent wind resources increases, making it difficult for system operators to utilize limited reserve capacity to compensate for periods of low wind power output (*ibid*). In a scenario with wind serving 50 percent of U.S. electricity demand, system operators would have to rely on very accurate wind speed forecasts in order to balance the risk of wind being a non-contributor against the risk of committing excess capacity (Milligan, 2000). Thus as wind becomes a larger contributor to U.S. electricity supply, accurate forecasts on both an hourly and daily timescale will become crucially important to avoid under- or over-commitment of capacity from contingency reserves, quick-start units, and slow-start units.

The capacity factor for wind systems can be increased by constructing backup capacity and storage facilities exclusively for large wind farms. Such an approach makes wind energy more reliable, but adds to the cost of the system. Such an economic penalty for making a wind farm reliable stems from the fact that dispatchable capacity is worth more than uncontrollable, intermittent capacity in wholesale electricity markets. In other words, large-scale wind should be reliable to prevent economic inefficiency and grid instability, and

reliable wind costs more than unreliable wind. This concept will be explored further in the optimization model presented in Section 2.

1.4 Location, Location, Location

Figure 1 indicates that much of the exploitable wind resources are located far from major demand centers that are mostly concentrated along the U.S. coastlines. Also, while there are significant wind resources near existing transmission infrastructure, these sites are not likely exploitable on a large-scale for two reasons: these resources tend to be of lower quality and the location of massive turbine arrays near demand centers is likely to cause considerable public opposition. If wind is to be utilized at a large scale, such as 50 percent of U.S. electricity supply, then the need for cheap land, low population densities, and strong wind resources will likely dictate that the bulk of the wind capacity be located in the remote, windy regions of the Great Plains and transmitted via long-distance transmission lines to demand centers.

Because wind power exhibits a cubic dependence on wind speed, wind turbine power output is very sensitive to location. Strategic exploitation of wind resources close to existing transmission infrastructure may not be cost-effective if the quality of the wind resource is lacking when compared to more remote wind sites. For instance, an investor looking to build a large wind farm with an average output of 1 GW could build the wind farm on the Pembina Escarpment of North Dakota in a wind class 5 area, and transport the electricity roughly 1000 miles to the Pennsylvania-New Jersey-Maryland (PJM) grid via high-voltage DC (HVDC) lines and incur roughly the same costs as simply installing the wind turbines in southwestern Pennsylvania, in a wind class 4 area and neglecting transmission costs. See Table 1.

Parameters	North Dakota Case	Pennsylvania Case
Wind Class	5	4
Capacity Factor (% of year at rated output)	32	28
No. of 1 MW turbines to meet 1 GW average demand	3030	3571
Capital Cost (\$/kW)	800.00	800.00
Fixed O&M (\$/kW-yrh)	15.00	15.00
Variable O&M (\$/MWh)	8.00	8.00
Average cost for 1000 mile HVDC-bipole (\$/kWh)	0.01	-
Average Cost (\$ / kWh)	0.04	0.04

Table 1. Simple spreadsheet to demonstrate the importance of wind farm location. The average generation cost was calculated as before in Figure 1, with the cost of transmission added into the North Dakota case. The average transmission cost (\$/kWh) was adapted from Hauth *et al*, 1997, and accounts for the low transmission line loading resulting from a wind farm with an assumed capacity factor of 25 percent.

Constructing long-distance transmission lines to utilize the best wind resources also provides the opportunity to geographically disperse wind turbine arrays and increase the reliability of the aggregate wind energy system. Geographic dispersion of turbine arrays over sufficiently large areas on the order of 1000 km can also increase the reliability of wind by averaging output over the scale of prevailing weather patterns. Kahn quantifies the reliability benefit of geographically dispersed wind turbine arrays using California data (Kahn, 1979). While the main thesis of the paper is that the geographical dispersal of turbine arrays improves the aggregate reliability, the ratio of ELCC (effective load carrying capability) to wind turbine capacity indicates that the diversity benefit reaches diminishing returns when the model is extended beyond Northern California to the entire Pacific region (*ibid*). However, the Pacific region may not be large enough to exploit the full benefits of turbine array dispersal by spanning synoptic scale weather patterns.

To investigate the degree of association between geographically dispersed wind turbines, wind data from the National Climatic Data Center (NCDC) was used to calculate the covariance matrix of wind speed vectors (NCDC, 2001). Covariance is the expected value of the product of the deviations of corresponding values of two variables from their respective means, and as such serves as a useful measure of association between dispersed wind sites. As the association between wind speed measurements drops, the covariance approaches zero. Figure 2 demonstrates that covariance decreases with distance and indicates that geographic dispersal of wind turbines serving the same load shows promise as a method to increase the reliability of wind power output.

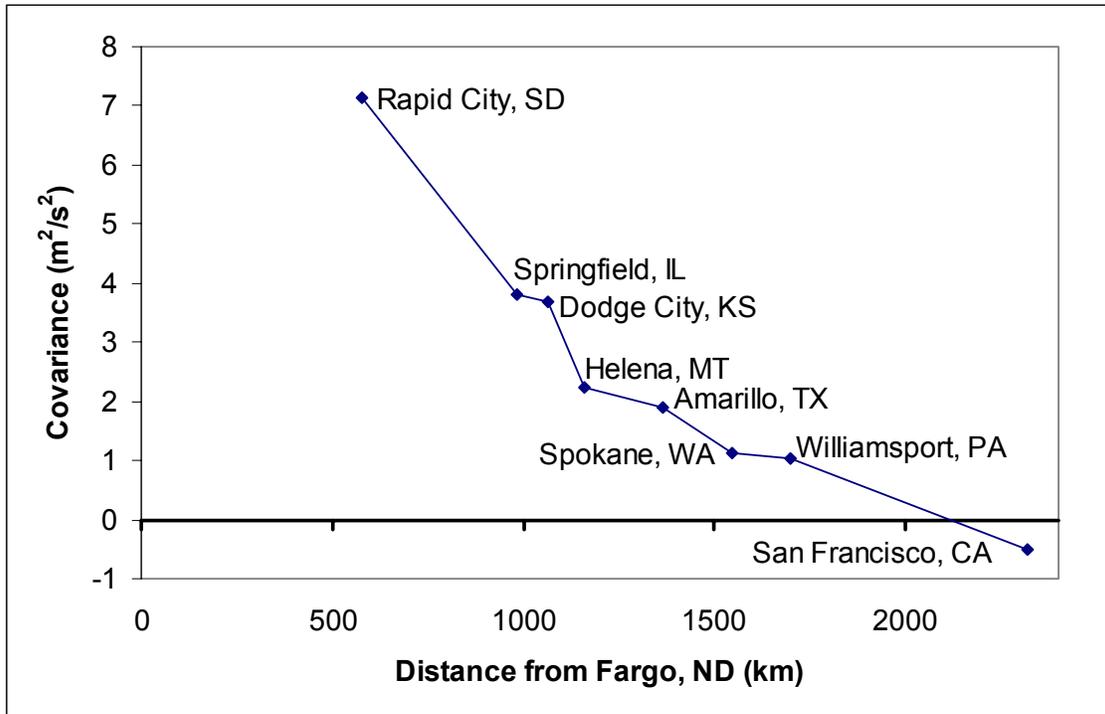


Figure 2. Covariance in m²/s² between wind speed vectors recorded at 8 different sites around the country and the wind speed vector from Fargo, ND. As expected, the greater the geographic separation between sites, the smaller the covariance.

2. A Nonlinear Constrained Optimization Model

The purpose of this optimization model is to provide a first-order economic characterization of large-scale wind when intermittency and remoteness cannot be ignored, thereby quantifying the difference between current estimates of average generation cost for small-scale wind energy and the future cost of reliable large-scale wind energy. The model utilizes geographically dispersed wind turbine arrays, a compressed air energy system (CAES) for storage, and backup gas turbines to meet a fixed load. The assumption of a baseload system with wind to meet a fixed load is a crude approximation to a model that incorporates the complex supply and demand dynamics that characterize electricity markets, but simplifies the analysis and provides a useful proxy.

2.2 Technologies in the Model

The model considers three technologies to increase the reliability of the wind energy system: 1) gas turbines, 2) compressed air energy storage (CAES), and 3) long-distance HVDC transmission.

2.2.1. Gas Turbines

Installing gas turbines is straightforward, and the costs are easily quantified. Gas turbines are a good choice for backup because the capital costs and CO₂ emissions are low compared to other fossil sources, and the turbine ramp rates are fast enough to adjust to quickly changing wind patterns. There will always be periods of zero wind turbine power output, so the backup gas capacity should be equal to the fixed load requirement the wind farm is trying to meet. Variable costs from gas consumption depend on the gas turbine utilization, which in turn depends on the meteorological characteristics of the wind site. Unfortunately, the use of gas turbines introduces CO₂ emissions.

The model includes both gas turbines (GT) and combined-cycle gas turbines (GTCC). Combined-cycle turbines have a heat recovery loop that increases efficiency and raises the capital cost. GTCC is more cost-effective than GT when run consistently over a long period of time because the savings in gas purchases stemming from higher efficiency outweigh the additional capital costs. However, GT is more cost-effective than GTCC when run as peaking units, because the lower capital cost outweighs the additional cost stemming from larger gas requirements. In the model, GT costs \$350 / kW at a Higher Heating Value (HHV) efficiency of 35 percent and GTCC costs \$500 / kW with an HHV efficiency of 55 percent.

2.2.2. Storage Systems

Adding storage flattens the wind energy supply curve without using additional generating units, but the functionality of both compressed air and pumped hydro systems is limited by the need for specific geologic formations, the size of the reservoir, and the installed compressor capacity. The degree to which a storage system can increase the capacity factor of a wind farm depends on the correlation between wind speeds measured at different points in time. The longer the autocorrelation time, the smaller the capacity factor of the wind-storage system will be. A storage system size of at least five times the autocorrelation time is needed to insure that its impact on the total system capacity factor (including all generators involved in electricity production) is negligible (Cavallo). The autocorrelation time for winds over the US Great Plains is between 6 and 10 hours, and the storage capacity should be approximately 60 to 80 hours (Cavallo). This result makes intuitive sense since synoptic scale weather patterns have an average period of a few days, and the storage system should be able to supplement wind at times of low energy production over this timescale.

Pumped hydro is a mature storage technology, with about 300 systems operating worldwide with capacities ranging from 20-2100 MW (Schoenung *et al*, 1996). Only two compressed air energy storage (CAES) facilities are in operation today. A third is being constructed in Norton, OH with an ultimate capacity of 2.7 GW to be achieved by adding 300 MW units incrementally (Sandia, 2001). The capital costs for both pumped hydro and CAES facilities are approximately \$500-\$600 / kW (Energy Storage Association, 2002).

The model is allowed to construct a single CAES facility at the Springfield, IL site. The assumed capital cost is \$500 / kW and the model was run twice with storage reservoirs of 1 and 10 hours. These small timescales reflect the size of the wind farms in the model, which could quickly deplete a compressed air reservoir in a matter of hours if the wind stopped blowing. The model optimizes the compressor capacity at the storage facility, which represents the maximum flux of energy in and out of the system. The maximum amount of energy that the facility is capable of storing is determined by the compressor capacity and the

storage reservoir volume. It is important to note that for simplicity the model does not take into account the gas consumed by the turboexpander to generate electricity at the storage site.

2.2.3 HVDC Transmission

Long-distance electricity transmission will be a critical component to the development of large-scale wind, particularly the geographic dispersal of wind turbines to work as a means of increasing reliability. To span the several hundred miles separating Great Plains wind energy from coastal demand centers, high voltage direct current (HVDC) lines will be in many cases more cost-effective than the equivalent three-phase HVAC lines. Assuming the same transmitted power, DC bipole line losses including skin effects and core losses are typically 65-73% of the equivalent 3-phase AC line (Hauth *et al*, 1997). Smaller DC line losses must be balanced by the higher capital cost and cost of losses associated with the DC to AC substations. Thus there is a break-even distance beyond which DC becomes more cost effective than AC, on the order of 100-400 miles depending on the specific configuration (*ibid*).

In the model, 408 kV DC-bipole transmission lines with a thermal line rating of 1934 MW are used to transport wind-generated electricity to the Chicago demand center. The cost of such a line is estimated to be \$530,000 / mile (Hauth *et al*, 1997). The cost per unit power (\$ / kW) depends on the length of the line, so the capital cost for each transmission line in the model was calculated by dividing the cost per mile by the thermal line rating and multiplying by the length of the transmission line. Finally the cost of the substations for AC/DC switching is added to the cost of the transmission line and towers. The transmission line cost calculation described above is given below in general form (quantities in parentheses represent units):

$$\text{capital cost} \left(\frac{\$}{\text{kW}} \right) = \text{capital cost} \left(\frac{\$}{\text{mile}} \right) \times \frac{1}{\text{thermal line rating}} \left(\frac{1}{\text{kW}} \right) \times \text{line length}(\text{miles}) \\ + \text{substation cost} \left(\frac{\$}{\text{kW}} \right)$$

2.3. Model Overview

The model's objective function minimizes fixed capital costs and variable gas costs by optimizing the amount of installed wind capacity, transmission capacity, storage capacity, backup gas turbine (GT) capacity, and backup gas turbine combined cycle (GTCC) capacity over a range of carbon taxes. Five wind sites were chosen and connected to Chicago via long-distance HVDC lines. All sites are at least wind class 4, and were selected for sufficient geographic diversity to span synoptic scale weather patterns in order to maximize the diversity benefit. The geometric configuration of wind sites is given in Figure 1.

The model contains 13 decision variables described in the list below. The number in parenthesis indicates the number of decision variables involved.

- Wind capacity at each of the five sites (5).
- Transmission line capacities between sites Fargo, Flagstaff, Amarillo, Williamsport and Springfield (4).
- Transmission line capacity between site Springfield and Chicago (1).
- Capacity of the storage system at Springfield (1).
- GT and GTCC capacities located at the Chicago demand center (2).

The parameter values used for capital costs, natural gas turbine efficiencies, and natural gas costs in the model are presented in Table 2.

Parameters	Values	Units
Natural gas cost	3.5	\$ / GJ
GT capital cost	350	\$ / kW
GTCC capital cost	500	\$ / kW
Wind capital cost	700	\$ / kW
Transmission line cost ¹	530,000	\$ / mile
Transmission substation cost	100	\$ / kW
CAES capital cost ²	500	\$ / kW
GT Efficiency (HHV)	0.35	
GTCC Efficiency (HHV)	0.55	

Table 2. Parameters used in the optimization model. The capital cost for wind is optimistic given the currently cited costs (McGowan, 2000), but is a reasonable projection for the next decade.

2.4 Model Input

Hourly wind data for each wind site in Figure 1 was obtained from the National Climatic Data Center (NCDC). NCDC makes available hourly wind recordings since July 1, 1996 from WBAN (Weather Bureau Army-Navy) stations (NCDC, 2001). Sites were chosen from a large database to reflect geographic diversity and reasonably strong wind resources (wind class 4). The data is stored as wind vectors roughly 50,000 elements in length. The NCDC data is unfiltered, such that a small fraction of hourly measurements were often missing or redundant. To correct this, the data was linearly interpolated in MatLab to reflect hourly measurements. Because the WBAN Station data is recorded at ground level, the wind vectors were scaled such that the mean of its elements was 7.25 m/s, or the mean wind speed of a wind class 4 site recorded at 50 meters above ground level. Wind turbine power output was obtained by running the wind speed vectors through a parametrized wind power output curve for a Vestas 1.75 MW turbine (Vestas, 2001). The cut-in speed was 4 m/s and the cut-out speed was 26 m/s. Below the cut-in speed and above the cut-out speed, the turbine produces no power. Between 4 m/s and 15 m/s, the power output has a cubic dependency on wind speed and between 15 m/s and 26 m/s, the turbine produces its rated power. These wind power vectors are loaded during execution of the cost function, and used to optimize the decision variables. For purposes of reducing the computational time, only the first 10,000 hourly measurements, representing slightly over a year, were used in the optimization. At least a single year of wind speed measurements must be used to be able to accurately capture seasonal variations in wind patterns.

2.5 Model Structure

The various functions and programs used in this model are presented in Figure 3.

¹ Hauth et al, 1997

² Cavallo, 2000

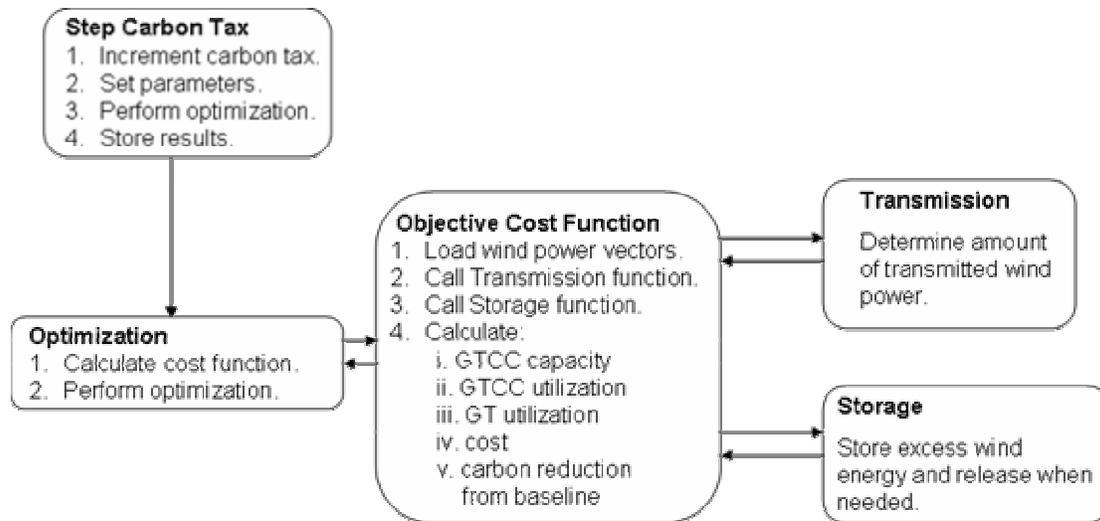


Figure 3. Structure of the optimization model showing the various functions and programs, and how they interact. The constraints in the optimization model were the decision variables can not be negative.

The model begins by incrementing the carbon tax and setting the parameters defined in Table 2. The cost of natural gas must be updated with the incremented carbon tax since gas combustion produces carbon dioxide emissions. Next, the optimization routine in MatLab is invoked to minimize the objective cost function by installing the optimal transmission, wind, gas, and storage capacities.

The cost function utilizes the wind power vectors described in the previous section. The cost function then implements the transmission and storage to functions. The transmission function is modeled as an arctangent for numerical simplicity because modeling the transmission line with a defined thermal line limit led to convergence problems within the optimization routine. Wind power traveling from Fargo, Flagstaff, Amarillo, and Williamsport to the central node in Springfield is sent to the storage function. Excess power from all five sites is stored in the CAES facility when capacity exists, and power from the CAES facility is released if the wind power delivered is less than the load to be met and a nonzero amount of energy is stored in the CAES facility at the time. Next, the GT and GTCC utilization needed to compensate the intermittent wind power to meet the fixed load is calculated. The gas utilization is used in the objective function to calculate the variable cost associated with natural gas usage. Finally the objective function, representing the sum of fixed and variable costs of the composite system, is calculated using capital costs, the cost of natural gas, and calculated capacities for each technology.

The optimization routine iterates the cost function to achieve minimum cost by changing the levels of installed capacities of the various technologies. The model is a time simulation of wind turbine power output embedded within an optimization routine. The installed capacities are unitless, and are calculated as the fraction of the fixed load. The model simulates a large-scale wind system due to the inherent scale of the transmission lines and the storage facility and their associated costs, which obey economies of scale.

2.3 Model Results

The optimization model calculates three quantities: 1) the optimal wind, transmission, storage, and gas turbine capacities at a given carbon tax, 2) the average cost per kWh, and 3) the fraction of carbon emissions reductions.

Five model runs were performed. In the first run, the dimensionality of the model was collapsed such that the model only had the option of installing wind capacity at Springfield, IL and the other wind sites were added one-by-one in arbitrary order in the four remaining runs. Forcing the model to optimize over different numbers of wind sites allowed for the quantitative assessment of the benefits of geographic diversity. In Figure 4, the marginal cost of carbon mitigation as a function site diversity is presented.

According to Figure 4, the carbon tax must be greater than \$175 per ton before the model begins buying wind capacity. The parabolic shape of the curve at high carbon taxes is a manifestation of the intermittency problem: no matter how much wind capacity is purchased, there are still times when the wind doesn't blow and the backup gas turbine capacity must be employed to meet the load. While adding geographically diverse wind sites reduces the number of hours in which wind output is zero and expands the carbon reductions frontier, there is still an effective limit imposed by intermittency. Despite this observable limit, Figure 4 indicates that there are significant benefits to geographical distribution of the wind turbine arrays. For example, in order to reduce carbon emissions by 40 percent with only a single wind site, the carbon tax must be nearly \$600 per ton. By comparison, reducing carbon emissions by 40 percent with access to all 5 wind sites only requires a carbon tax of roughly \$250 / ton. Also note that adding Flagstaff site does not add any benefit. Figure 1 provides the explanation: the cost of the transmission line from Flagstaff to Springfield is prohibitive due to its length relative to the other transmission lines.

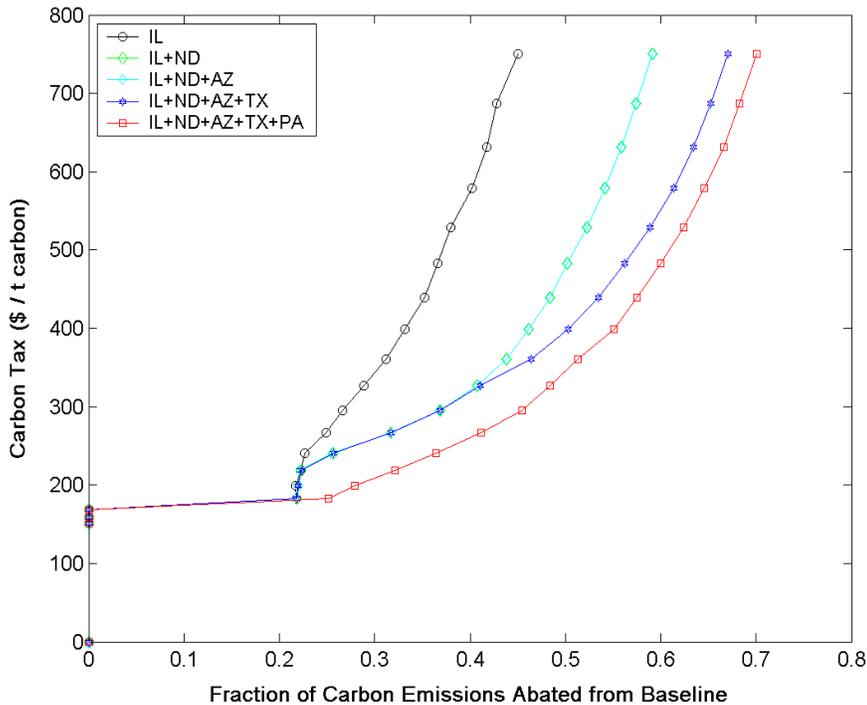


Figure 4. Carbon emissions reductions as a function of carbon tax. These curves represent the marginal cost of carbon mitigation as a function of site diversity. Note that making additional wind sites available to the model increases the achievable carbon reductions. Also note that when wind is first purchased in the greenfield model around a carbon tax of \$175/ton, the emissions reductions achieved are relatively small. This phenomenon may be an artifact of the optimization routine or indicate that small purchases of wind have a disproportionately small effect on carbon emissions, stemming from the intermittency problem. The baseline scenario corresponds to zero carbon tax and the purchase of only GTCC capacity. The abbreviations in the legend are the state codes for states in which the wind sites are located.

The carbon tax determines the optimum amount of wind capacity to purchase, which increases as the tax rises. As more wind is purchased, the amount of carbon emissions reductions increases from the baseline scenario. Figure 5 presents the cost of electricity as a function of the fractional carbon reductions from the baseline scenario. It is important to note that the carbon tax is not included in the cost of electricity. The economic benefits of geographic site dispersal are significant: for a 40 percent reduction of carbon emissions from the baseline scenario, the cost of baseload electricity employing one wind site is 5.5 ¢/kWh whereas the cost with five wind sites is 4.8 ¢/kWh.

Figure 5 represents the key model result: for a given level of desired carbon emissions reductions, the cost of baseload wind is provided. This figure quantifies the difference in cost between current small-scale applications and potential large-scale wind applications. For example, the added cost to make the wind system capable of meeting a fixed load is 2.5 ¢/kWh if the desired carbon reductions target is 50 percent below the baseline. Thus the model indicates that the cost of reliable wind is in the range of 5-7 ¢/kWh, comparable to other zero emissions energy technologies such as nuclear or coal with carbon capture.

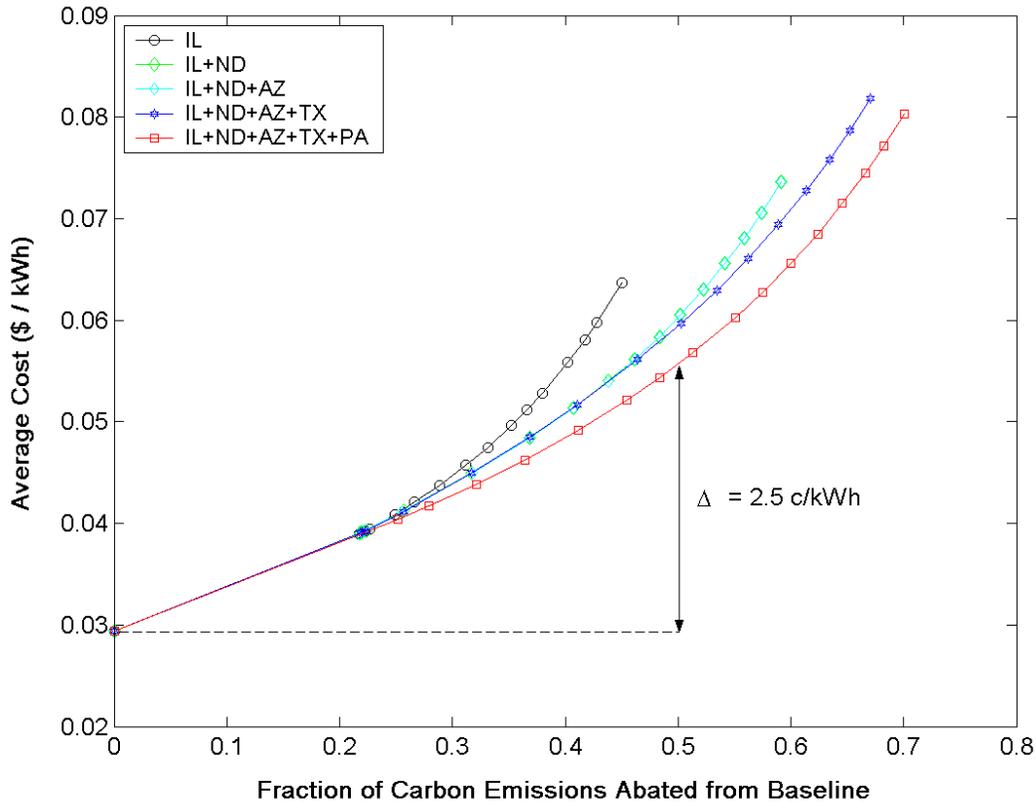


Figure 5. This is the key result from the model: the cost of electricity from a baseload system incorporating wind as a function of the level of carbon reductions. For example, the cost to reduce carbon emissions 50 percent below the baseline using wind averages 5.5 ¢/kWh, which is comparable to other zero emission energy technologies. Also note that the utilization of geographically diverse sites substantially lowers the cost of electricity for a given level of carbon reductions.

In addition to geographical site diversity, storage was added to increase the reliability of wind power reaching the demand center. Storage was implemented in the model for storage capacities of 1 hour and 10 hours. Since the purpose is to assess the cost of large-scale wind, the rated discharge power of the facility must be large to affect the variance of wind power output. As such, the amount of time the storage facility will be able to discharge at rated power will be relatively short, justifying the choice of short storage timescales for this model. See Figure 6.

Storage and wind are purchased together beginning at an entry level carbon tax of \$175/ton, which allows for the attainment of higher carbon reductions by displacing gas turbine capacity. For example, at a carbon tax of \$500/ton, the 10 hour storage facility allows for a 12 percent increase in carbon reductions in the single wind site case and an 8 percent increase in the five wind site case. The baseload wind system costs with storage are equal to or slightly less than the systems without storage. For example, at a 50 percent reduction of carbon emissions, there is little cost difference between the 1-site system with 10 hours of storage and same system without storage (5.5 ¢/kWh). The same is true for the 5-site system.

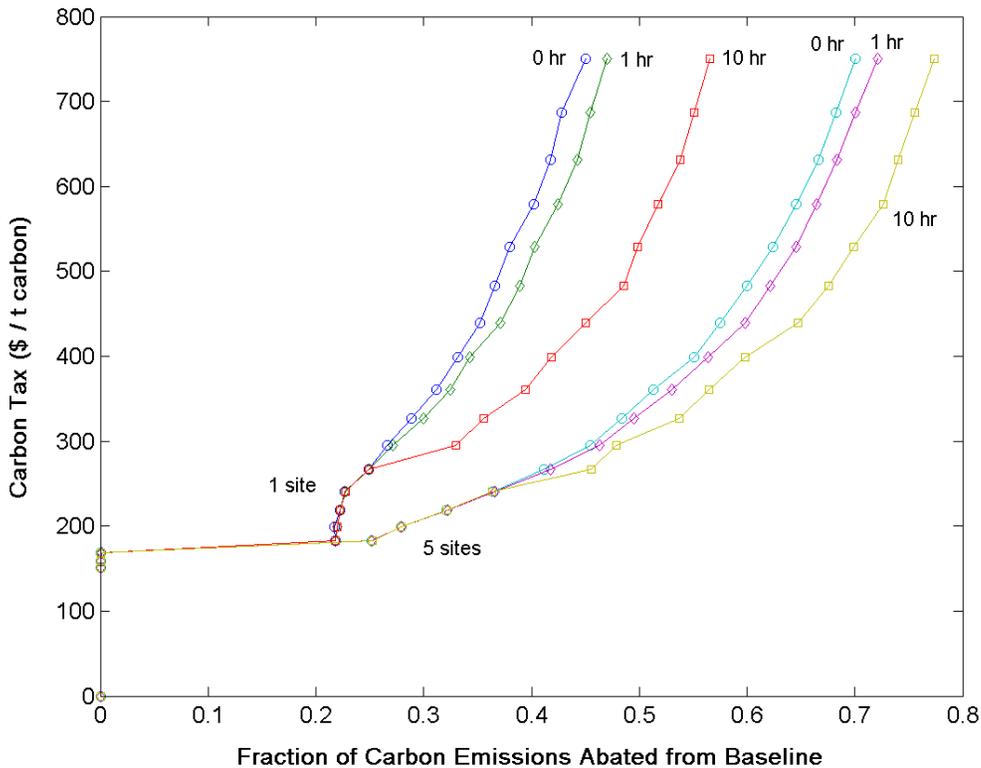


Figure 6 Carbon emissions reductions as a function of carbon tax for the 1-site and 5-sites case, both with and without storage. The storage capacity is listed above each curve in hours. While the 1-hour facility only yields marginal benefits, the 10-hour facility significantly expands the ability of a wind system to meet higher levels of carbon reductions.

3. Conclusions

Wind could enable deep reductions (~50 percent) in CO₂ emissions from electricity generation, but at this scale the problems posed by the remoteness and intermittency of the

wind resource must be addressed. Our objective was to quantify the difference between current cost estimates of small-scale wind energy and the future cost of large-scale wind energy. The greenfield analysis presented in Section 2 of this paper provides a first-order economic characterization of a baseload system involving wind in which long-distance transmission, backup gas capacity, and storage are used to supplement the variable wind power output to meet a fixed load. The greenfield model of wind in a baseload system represents a crude approximation to real electricity markets and provides a rough estimate of the additional costs beyond the cost of power at the wind turbine. As evidenced by Figures 4 and 5, a 50 percent cut in carbon emissions is achievable with a \$350/ton carbon tax at a cost of roughly 5.5 ¢/kWh. The model suggests that baseload wind is competitive with other carbon-mitigating energy technologies, such as coal with carbon capture or nuclear, and warrants further investigation. Though the carbon tax to motivate wind development is quite large, it is important to realize that the average cost calculated for the wind system does not include the carbon tax. Thus other regulatory mechanisms could be employed to motivate the development of large-scale reliable wind at the same costs.

Unfortunately, there are significant regulatory impediments that will tend to frustrate the development of large-scale wind in the United States. A major regulatory problem is the difficulty in siting transmission lines. The institution of federal eminent domain over transmission lines may be a crucial step towards alleviating the archaic system of overlapping federal, state, and local siting processes that delay many badly needed transmission projects. The greenfield analysis underscores the importance of long-distance electricity to the successful development of baseload wind. Another problem stems from the short-term wholesale electricity markets and the limited ability of wind generators to accurately predict future output. The closer intermittent renewables are allowed to schedule to dispatch time in the wholesale market, the less chance of incurring schedule deviation costs.

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