

Integrated Coal and Wind Power Development in the U.S. Upper Great Plains

A CONCEPT PAPER¹



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Overview

The U.S. Upper Great Plains is blessed with both vast quantities of low-cost lignite coal resources and high-quality wind resources. These resources lend themselves to the development of domestic power sources that have the potential to improve the environmental performance of the U.S. electricity industry and provide a source of stable and secure domestic energy supplies for the nation. For these reasons, there is an emerging interest in the joint development of both wind and coal resources in the region.

The potential for wind development in the Upper Great Plains is significant. By our estimate, as much as 104 gigawatts (GW) of the region's wind power resources may be suited for development, yet only 110 MW of these resources have been developed. The Upper Great Plains is also home to the northern lignite coal supply region in eastern Montana and western North Dakota, which contains enough lignite to provide the lifetime fuel requirements for over 220 GW of additional reliable, low-cost coal-fired generating capacity.² These lignite reserve estimates do not include the considerable sub-bituminous reserves found in the Northern Powder River Basin region of Montana. More than 25 million tons of lignite per year from this region are currently produced and utilized in several mine-mouth power plants with a combined electricity generating capacity of 4,173 MW. These plants are concentrated to the northwest of Bismarck, North Dakota. Substantial additional lignite reserves are available, but have not yet been developed in other parts of the region.

The problem is that the areas with the highest concentration of coal and wind resources are far from major electricity markets, and the transmission capacity currently does not exist to move electricity from prospective generation facilities to the market. Great Northern Power Development L.P. (GNPD), an affiliate of Great Northern Properties L.P. (GNP) – the nation's largest private coal landowner, has offered a potential solution to this problem. GNPD, as part of its project development activities, has been exploring opportunities for the development of a coal plant with a co-located wind farm that is dispatched to respond to minute-to-minute wind farm output variations to ensure a constant combined plant output. These plants would be jointly connected to electricity markets through newly constructed transmission capacity. If constructed, these transmission and generation assets would begin the process of opening up the region's vast untapped energy resources, while providing much needed stimulus and diversification for the regional economy.

If, indeed, new coal power plants possess the technical ability to match minute-to-minute variations in wind power output, then the joint system would be capable of delivering a non-intermittent bundled power product to the market via new transmission capacity. The responsibilities and duties traditionally associated with integrating an intermittent resource into the power system would be transferred from the system operator to the power supplier.³ This would enhance the value proposition of the joint coal-wind system

² Lignite Energy Council, from <http://www.lignite.com/why/abundant.htm> (accessed September 18, 2003).

³ In the context of this report, we define system operator as the power purchaser, who is presumed to have a control area or has contracted for control area services.

by making the integration of wind power seamless from the system operator's perspective.

While there are clear conceptual advantages to the development of an integrated coal-wind system that is capable of delivering constant output to the market, there are also significant uncertainties surrounding this concept, which has not been commercially demonstrated in practice. For instance, do new coal power plants have operational characteristics that would allow for minute-to-minute co-dispatching with wind output? If so, what are the economic and environmental characteristics of the joint system? Could a joint system—with a coal plant operating below maximum capacity during windy periods—accrue enough revenue to provide adequate cash flow and returns in order to support joint project development? If so, what is the appropriate wind farm size? The answers to these questions depend upon the market value for power in the Upper Great Plains, the technical performance of new coal-fired power plants, and the minute-to-minute variability of wind power production. All of these questions will be examined in this report.

Platts Research & Consulting (PR&C) has been engaged by GNPD to conduct an operational, financial, and environmental analysis of the prospects for an integrated coal-wind power project in the Upper Great Plains. GNPD has asked PR&C to answer the following three questions:

1. What is the technical feasibility of co-dispatching a new coal-fired power plant to match variations in expected wind power output?
2. What is the appropriate capacity of wind farm to be developed with the coal plant?
3. What is the expected economic and environmental performance of a joint coal-wind system at alternative wind farm capacities?

In Section I, we provide context for the discussion by characterizing and assessing wind resources in the Upper Great Plains. In Section II, we explore the feasibility of coal-wind co-dispatch from a technical and operational perspective. Section II contains a summary of a series of interviews with coal plant equipment vendors and operators designed to assess the technical ability of a new coal-fired power plant to vary output rapidly enough to match variations in wind output. This section also contains a characterization of historical minute-to-minute wind farm output variations based on wind generation data for two major wind farms in the Midwest from the National Renewable Energy Laboratory (NREL). Section II concludes with an analysis of wind farm size, which is a function of the coal plant ramp rate, expected minute-to-minute variation in wind power output, and other factors.

The economic and environmental performance of a prospective combined coal-wind system is analyzed in Section III. This analysis was conducted using PR&C's proprietary generation and transmission asset financial valuation model. The economic and environmental analysis presented in Section III is performed for a hypothetical 500 MW coal plant across a range of wind farm sizes from 1 to 100 MW. We explore both stand-

alone and co-dispatch scenarios and examine the impact of transmission costs on integrated system costs. In addition, the impact of wind resource quality on project economics is examined. The role of the federal production tax credit (PTC) is also discussed.

Key Findings⁴

Overall, we find that while coal-wind integration has not yet been commercially demonstrated, it is expected to be both operationally and environmentally feasible. Its financial feasibility will vary on a site-specific basis, and will be dependent upon energy market prices, project hurdle rates, wind farm size, wind resource quality and policy support, and transmission access and economics. In particular, we find that:

- The Upper Great Plains has vast quantities of undeveloped low-cost coal and wind resources. However, transmission capacity limitations restrict the development potential of the region's vast electrical energy resources.
- Wind's intermittence impacts its transmission economics – both in terms of justifying transmission expansions and in securing transmission rights. One potential solution is for new wind projects to rely on non-intermittent resources such as coal to provide the assured dispatchable capacity required to support the development of new transmission capacity or the acquisition of “firm” transmission rights, and then cause the dispatchable resource to operate below maximum capacity in order to “make room” for wind energy.
- This approach would rely upon the co-dispatch of coal and wind generators to allow for firm utilization of transmission capacity. Based on a series of interviews with coal-fired power plant equipment suppliers and operators, and an examination of minute-to-minute wind power output variability for large wind farms, we find that there is a high theoretical degree of technical feasibility for the co-dispatch of a new coal-fired power plant to match minute-to-minute wind power output variations.
- At a coal plant ramp rate of 5-15 MW/minute, a combined system with a 500 MW coal plant and a 20-60 MW wind farm is expected to support co-dispatch that yields a combined system output as constant as that of a stand-alone coal plant. This analysis is based on the two predominant technical factors in wind farm sizing under coal-wind co-dispatch: wind farm output variability and coal plant ramp rate. In this case, wind generation would account for 4-12% of total capacity and about 2-5% of combined system energy output. At this juncture in exploring the coal-wind integration concept, however, there is no basis for calculating the “correct” size of a co-located wind farm.

⁴ All findings presented in 2003 \$s.

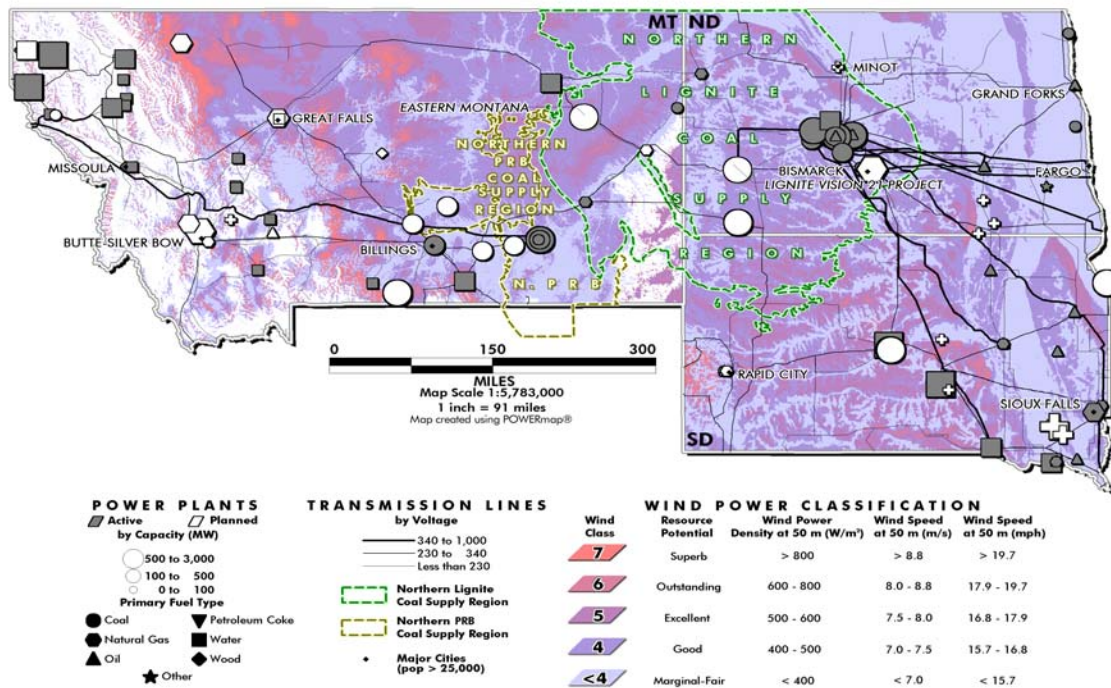
- The larger the wind farm size, the lower the internal rate of return (IRR) for the combined system, assuming co-dispatch, because of the decrease in the coal plant's capacity factor and impacts on coal plant operations. We estimate that the IRR for a new hypothetical 500 MW circulating fluidized bed (CFB) coal plant will decrease by approximately 1 percent for every 30 MW of wind capacity incorporated into the project. This highlights the economic constraints on the wind farm capacity. Investors and other project stakeholders are likely to tolerate some IRR reduction to incorporate wind capacity, but at high levels of wind capacity, the IRR may erode to an unacceptable level.
- Our analysis shows that SO₂ and NO_x from a new hypothetical 500 MW CFB equipped with required pollution control equipment will decrease by 1 percent for every 13.6 MW of wind capacity incorporated into the project.

Section I. Wind Resources in the Upper Great Plains

Resource Characterization

As illustrated in Figure 1, the potential for wind development in the Upper Great Plains is significant. According to our geographic information system (GIS) analysis using the latest wind resource assessment, as much as 104 gigawatts (GW) of the region's wind power resources may be suited for development. To date, only 110 MW of these resources have been developed. Figure 1 also highlights the northern lignite coal supply region in eastern Montana and western North Dakota, which contains enough coal to provide over 1,360 years of reliable, low-cost power supply at current production levels, or the lifetime fuel requirements for over 220 GW of additional coal-fired generating capacity.⁵ More than 25 million tons of lignite per year from this region are currently produced and utilized in several mine-mouth power plants with a combined electricity generating capacity of 4,173 MW (an additional 6 million tons of lignite per year is consumed in a large mine-mouth gasification plant). These plants are concentrated to the northwest of Bismarck, North Dakota. Substantial additional lignite reserves are available, but have not yet been developed in other parts of the region.

FIGURE 1: ELECTRICAL ENERGY RESOURCES IN THE U.S. UPPER GREAT PLAINS



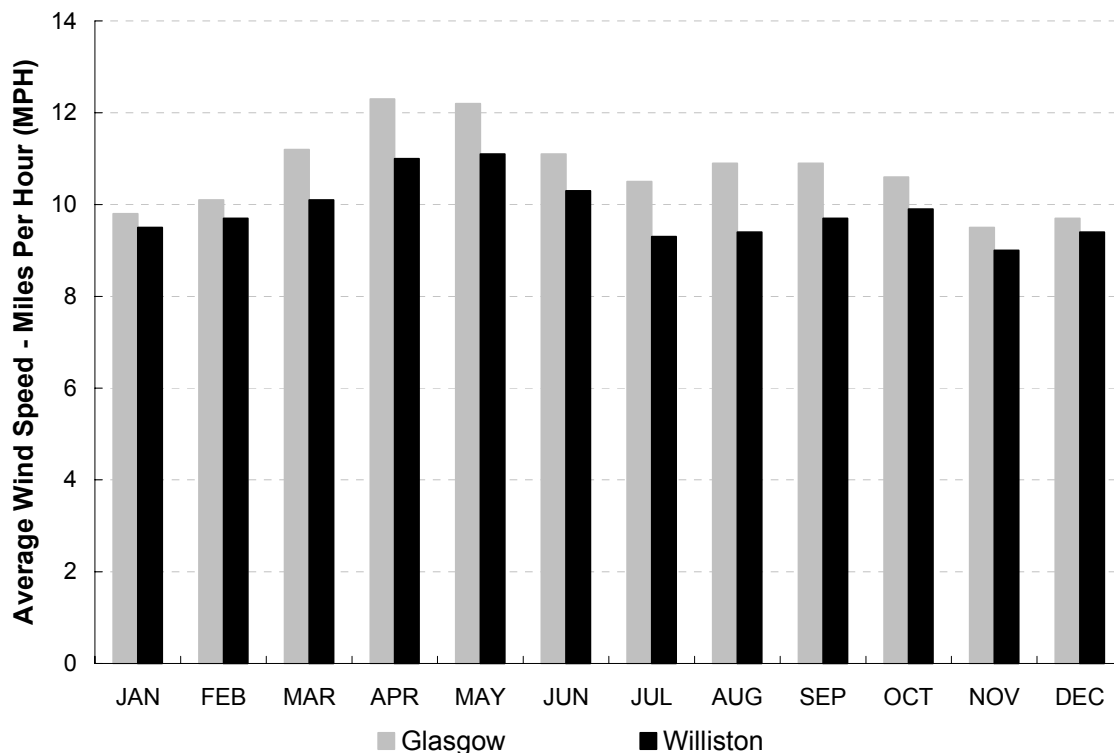
The wind power resource estimates were produced by TrueWind Solutions using their Mesomap system and historical weather data. This map has been validated with available surface data by the National Renewable Energy Laboratory and wind energy meteorological consultants.

SOURCE: PLATTS

⁵ Lignite Energy Council, from <http://www.lignite.com/why/abundant.htm> (accessed September 18, 2003).

To develop a preliminary assessment of wind resources in the Upper Great Plains on a daily and seasonal basis, we turned to data from airport-based weather stations operated by NWS. We selected two airport locations, which we believe are most representative of the wind resources in the Upper Great Plains. These locations are at Glasgow in northeastern Montana, and at Williston, in western North Dakota. These locations were selected based on data availability. Ideally, locations near lignite resources would have been selected, but data availability from such sites was limited. Wind patterns at the two airports (roughly 145 miles apart) are similar both seasonally and daily, so it can be expected that wind speed patterns are relatively similar across the Upper Great Plains. As illustrated in Figure 2, average wind speeds are fairly consistent on a monthly basis, with the highest and lowest months within 25 percent of each other. Both locations report a strong average wind speed through the spring months of March, April, and May – months where load demand tends to be soft and electricity markets are depressed. Wind speeds fall in June and July, and then increase somewhat in the fall months. Wind speeds are weakest in the winter months from November to February when electricity demand is generally strong. The month-to-month average wind speeds are based on more than 30 years of data at each airport.

FIGURE 2: ANNUAL WIND PROFILES BY MONTH IN THE UPPER GREAT PLAINS



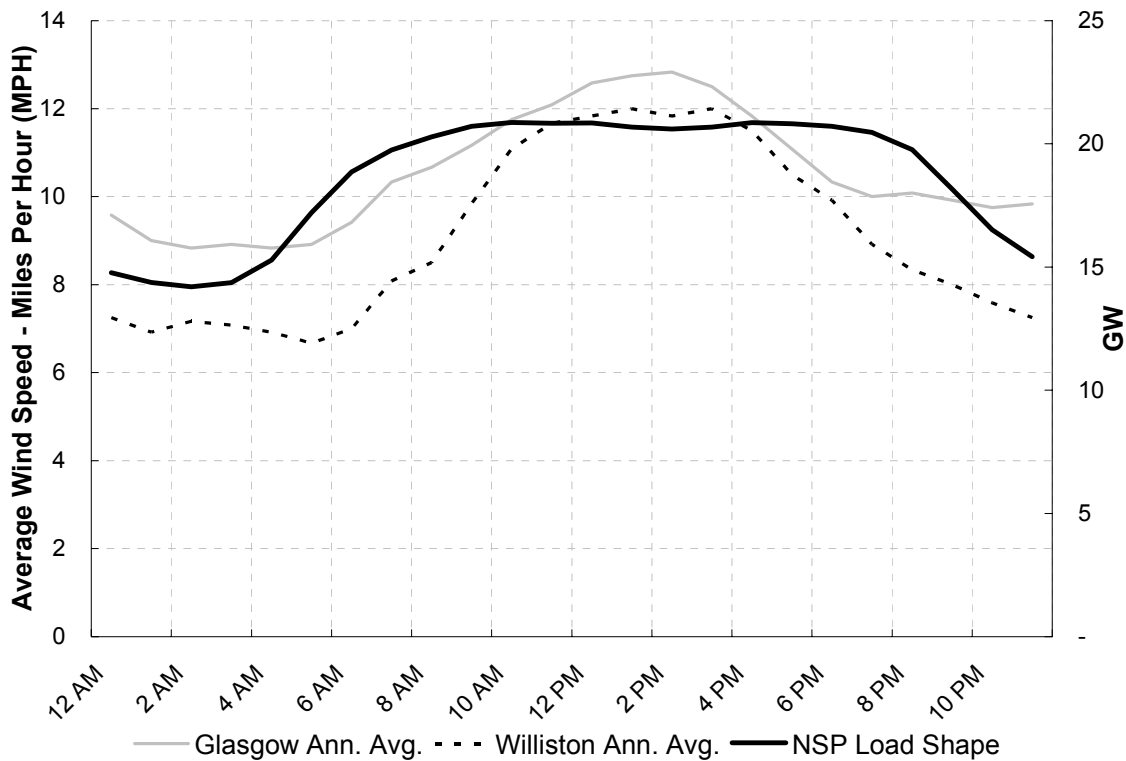
SOURCE: PLATTS

As illustrated in Figure 3, the daily profiles of wind speed are also similar at these two airports. Data was available for average wind speed by hour in each month in 2002. The two sites show a daily wind profile that is generally favorable with respect to typical load matching requirements, and we have plotted an average daily load profile for Northern

States Power (NSP) against wind speeds to illustrate this. On an average day, wind speed starts to increase at roughly 6 AM, reaches a peak between noon and early afternoon, and then declines in the late afternoon or early evening. Average wind speeds are lowest during the off-peak hours at night. The overall wind speed profile appears to be largely consistent from season to season, ramping up in the morning and down later in the day. There are seasonal differences in what time the wind speeds begin to decrease in the afternoon and early evening, but wind speeds are consistently lowest at night when the demand for power is low.

Although these wind patterns are not a perfect match to load requirements, the data shows the possibility for a better-than-average system match compared to a typical wind site. Some wind sites in the U.S. have not matched load nearly as well as this data indicates will occur in the Upper Great Plains.

FIGURE 3: DAILY WIND PROFILES BY HOUR IN THE UPPER GREAT PLAINS



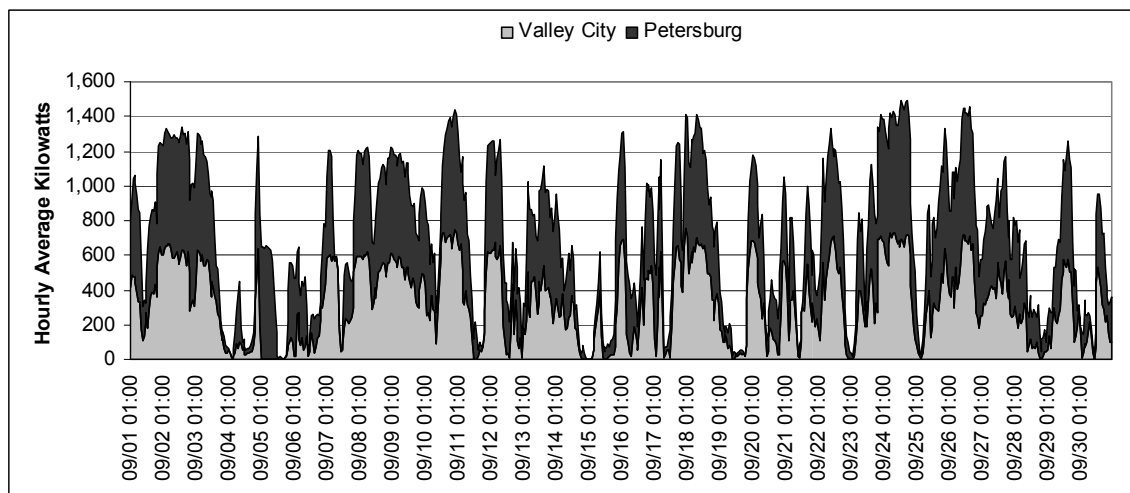
SOURCE: PLATTS

Up to this point, we have looked only at wind speed data. In addition to this wind speed data, there is some public data for actual wind generation available from Minnkota Power Cooperative, who has developed two 900 kW wind turbines in North Dakota. While the generation from these projects does not represent the output from a large-scale wind farm, these projects demonstrate that good capacity factors are possible in the Upper Great Plains – both projects have produced 34% average capacity factors. This data also demonstrates that projects roughly 80 miles apart can have similar generation profiles.

An output profile is shown in Figure 4 to illustrate actual wind generation in the Upper Great Plains:

FIGURE 4: WIND GENERATION IN THE UPPER GREAT PLAINS

Stacked September 2003 generation data for two 900 kW wind turbines in North Dakota



SOURCE: MINNKOTA POWER COOPERATIVE

Accounting for Transmission

The wind resources illustrated in Figure 1, and the seasonal and diurnal patterns in Figures 2 and 3, indicate that the Upper Great Plains is a highly attractive region for wind power development. However, the availability of high-quality load matching wind resources is not the only criterion to consider in examining wind potential. To complete this assessment, we must consider the costs and impacts of transmission on the delivered wind-generated electricity to the system operator. Because wind energy is an intermittent resource, it is optimally delivered on an “as-available” basis. Under this delivery method, if wind is available, then electricity is transmitted and the cost of the transmission is ascribed to the wind-generated electricity. On the other hand, if wind is not available, then power is not produced and the cost of transmission is not ascribed to the wind-generated electricity. The challenge of this as-available or “non-firm” approach is that transmission may not be available when the wind is blowing.

The break-even point for determining whether to use non-firm or firm transmission services to move energy from the generator to the market occurs where the cost of hourly non-firm transmission and long-term firm transmission are equal. This break-even point varies based on underlying transmission asset economics, but is likely to occur between 50 and 100 percent of transmission capacity utilization. Since even the most promising wind farm development locations cannot support a 50 percent capacity factor, this means that as-available wind energy output is best suited to the utilization of non-firm transmission services. Of course, this also means that transmission upgrades and

expansions cannot be supported exclusively by wind projects; these costs must be borne by more dispatchable resources.

If, however, dispatchable resources, such as coal-fired generators, which have the ability to operate at a high capacity factors in order to support new transmission investments and contract for firm transmission rights, were to operate at reduced capacity levels to “make room” for wind energy on the newly constructed transmission lines, then both coal and wind energy could be delivered to electricity markets. This is the solution proposed by GNPD, with the additional aspect of co-dispatch between the coal plant and wind farm on a minute-to-minute basis to ensure a constant combined plant output and maximize transmission capacity utilization. Of course, the wind farm must be developed on a scale that does not result in the underutilization of the coal-fired asset to a degree that negatively impacts coal plant operations or pushes the rate of return for the integrated project below a level that is acceptable to equity investors. We explore the technical feasibility of GNPD’s concept in Section II, and examine its economic feasibility in Section III.

Section II. The Technical Feasibility of Coal-Wind Co-Dispatch

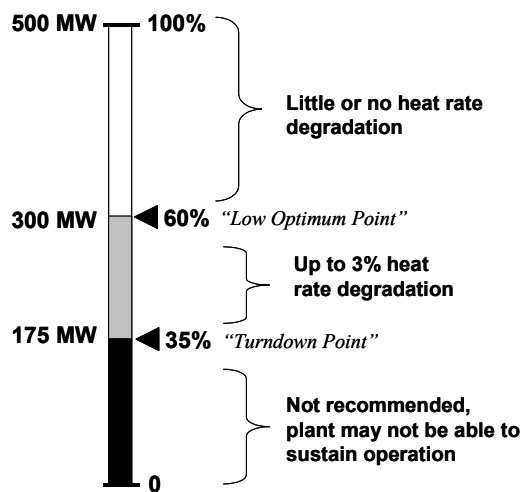
We conducted interviews with coal plant equipment vendors and operators to determine if coal-fired power plants possess the capability to follow the minute-to-minute output of a wind farm. Two major coal plant equipment manufacturers and operating superintendents from five major coal plants were interviewed. Operators of four large circulating fluidized bed (CFB) coal plants (two new plants and two ~15 year old plants) were interviewed, and an operator of a modern pulverized coal (PC) plant in a system considering adding wind capacity was also interviewed. The findings from these interviews are summarized below.

Coal Plant Technical Capability

Heat Rate

The first issue to be examined when validating the feasibility of coal-wind co-dispatch is whether or not the heat rate of the coal plant is affected by operating below maximum output. Interviews with CFB vendors indicate that the heat rate of a new CFB plant would remain very close to its optimum heat rate within the range of 60 to 100 percent of plant output. In other words, a hypothetical 500 MW CFB plant should be able to obtain a near-optimal heat rate if operating between 300 MW and 500 MW. In addition, according to interviewees, it becomes impractical to operate a coal-fired power plant below 35 percent of maximum output, or 175 MW for a hypothetical 500 MW plant. These two points are defined herein as the “low optimum” and “turndown” points, respectively, as illustrated graphically in Figure 5.

FIGURE 5: GRAPHICAL ILLUSTRATION OF COAL PLANT EFFICIENCY WITHIN ALTERNATIVE OPERATIONAL REGIEMES.



SOURCE: PLATTS

The PC plant operator suggested that the heat rate would suffer slightly as a result of the coal plant having to “chase” a moving load target as it follows wind generation. The minor efficiency loss results from the coal plant not being able to optimize its heat rate at one steady-state output level. This operator estimated this heat rate penalty at 50-100 btu/kWh.

Ramp Rates

Next, we asked interviewees about coal plant ramp rates to determine if a modern coal plant could change its output quickly enough to follow output changes from a linked wind farm. The interviewees indicated that new coal plants have sufficient ramping capabilities to follow minute-to-minute wind farm output fluctuations. As expected, coal plant equipment vendors were more optimistic than operators of existing coal-fired power plants about ramp rates. Ramp rates of 3-10 MW/minute (0.6-2.0% of plant capacity) were reported by operators, while vendors quoted ramp rates in the 15-25 MW/minute range (3-5% of plant capacity). However, these ramp rates are dependant upon actual plant loading, so in the case of unit loading at the “low optimum point”, such ramp rates would only be 60% of the values noted in the preceding sentence to ensure that the plant isn’t negatively affected.

Ramping Frequency

Another important question is the extent to which frequent ramping to follow wind farm output will detrimentally affect the coal plant, particularly in terms of variable operating and maintenance cost increases. The interviewees indicated that frequent ramping of a coal plant would have minimal detrimental effects on the variable operating and maintenance costs of a coal plant.

When asked how frequent ramping would affect the plant and its costs over the plant lifetime, vendors were confident that ramping between the low optimum point and maximum output, at the ramping rates discussed above, would present minimal technical difficulties for the new generation of coal plants. One CFB operator was similarly confident that a CFB plant could operate under a frequent ramping scenario with little performance degradation or cost impact, and pointed out that his plant responds to ramp requests from the local electric grid operator frequently; load-following operation is routine for the plant. The operator noted that this plant ramped from its turndown point to maximum output and back down on a daily basis for several years to follow a daily peak load profile. It is acknowledged, however, that such ramping is considerably less intermittent than that which would be experienced in co-dispatching with wind.

However, another CFB plant operator was more skeptical about the ability of a CFB plant to ramp frequently. This operator represented a plant that is operated strictly for baseload purposes and not subject to load-following. This operator speculated that ramping up in response to a drop in wind farm output would be relatively easy, but ramping a CFB down may be more difficult due to fuel overloading problems. These problems could be mitigated if ramping instructions were given 15-20 minutes ahead of when the ramp

down would be required, well within the temporal range provided by current wind forecasting systems, which combine real-time metrological information with sophisticated forecasting techniques.

Coal Plant Technology Comparison

It appears that a new PC plant could co-dispatch with a wind farm with largely the same performance as a CFB plant. In addition to the PC operator interviewed, one vendor was asked specifically about PC versus CFB technology in a wind-following operational scenario. The representative felt that a PC plant would perform similarly to a CFB plant. He felt that a “negligible” amount of non-fuel variable cost increases might be seen in a PC unit as compared to CFB technology.

Hypothetical Coal Plant Operational Characteristics

Based on input from the above interviews, PR&C developed a set of baseline operating assumptions for a new hypothetical 500 MW lignite-burning coal plant located in the Upper Great Plains. These assumptions are listed in Figure 6.

FIGURE 6: HYPOTEHTICAL COAL PLANT OPERATIONAL CHARACTERISTICS

General	
Plant Size (MW)	500
Plant Type	CFB/PC
Fuel Type	Lignite
Capability (MW)	
Maximum	500
Low Optimum	300
Turndown	175
Heat Rate (btu/kWh)	
Maximum Output	10,300
Low Optimum	10,300
Turndown	10,600
Ramp Rate (MW/min.)	
Ramp Rate Up	5-15
Ramp Rate Down	5-15

SOURCE: PLATTS RESEARCH & CONSULTING

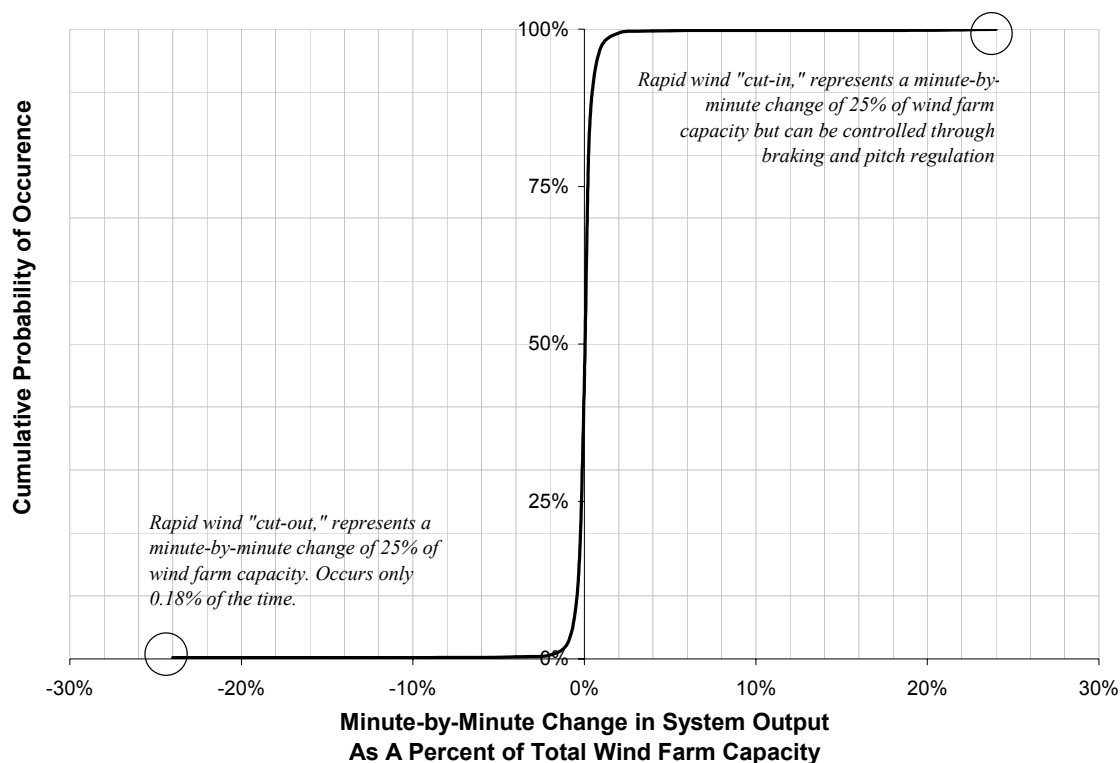
Wind Farm Output Variability

It is clear from operator and vendor interviews that coal plants possess the capability to adjust output very quickly to meet changes in wind farm output, with the new generation of coal plants potentially more responsive than the fleet of coal plants currently in operation. Still, in order to determine the feasibility of coal-wind co-dispatch, we must understand how quickly a coal plant would be required to change its output in response to real-time wind farm output variations and determine if the required ramp rate falls within the capability of the coal plant. To do this, we need to understand the minute-to-minute generation profile of a wind farm in the Upper Great Plains. Note that this analysis reflects the collective intermittence of a wind farm and not individual wind turbines which are expected to exhibit more pronounced intermittence.

We estimate the wind power output profile of a hypothetical wind farm in the Upper Great Plains by examining the minute-to-minute historical generation profile of two large wind farms in the Midwest. This data was generously provided by the National Renewable Energy Laboratory (NREL), and represents minute-to-minute electrical output over a two-year period from two anonymous wind farms with over 50 MW of capacity each, representing a total of more than 100 units. We assumed that the minute-to-minute variation in the NREL wind farm electrical output data is representative of the likely minute-to-minute variation for an Upper Great Plains wind farm. NREL's wind resource and technology specialists opined that this is likely to be a valid assumption.

In our examination of the NREL wind generation data set we found that, on a minute-to-minute basis, wind farm output variation falls within 1 percent of total wind farm capacity 97 percent of the time (one standard deviation). This means that output from a 100 MW wind farm will vary by 1 MW or less on a minute-to-minute basis 97 percent of the time. Further, we found that wind farm minute-to-minute output variation falls within 2 percent of total wind farm capacity 99 percent of the time (two standard deviations). Figure 7 shows a minute-to-minute wind system output change cumulative probability of occurrence diagram based on the NREL data set. There are a small number—less than 1 percent of occurrences—of instances where wind farm output could vary by up to 24 percent of rated capacity. This is due to wind turbines “cut-in” and “cut-out” speeds, points that determine when the wind is too slow or too fast for generation. As wind speeds reach these points, the turbines come on-line or go off-line, and these events cause the higher variances in minute-to-minute wind output along the tails of the distribution presented in Figure 7.

FIGURE 7: MINUTE-TO-MINUTE WIND SYSTEM OUTPUT CHANGE PROBABILITY OF OCCURRENCE DIAGRAM



SOURCE: PLATTS WITH DATA FROM THE NATIONAL RENEWABLE ENERGY LABORATORY (NREL)

It is important to note that the data points along the right tail of the distribution presented in Figure 7 are not relevant for the purposes of assessing the prospects for coal-wind co-dispatch. This is because modern wind turbines have the ability to control the rate of wind power cut-in. This type of control is achieved through braking systems and turbine blade feathering. Braking systems were originally designed to protect turbines by stopping them in very high winds, or for maintenance purposes, but can be used in conjunction with blade feathering capability to keep ramp-up rates within a desired range, which means that the wind farm operator can control positive minute-to-minute variations.

Less can be done to control wind output ramp-down rates. Thus, the data points along the left tail of the distribution presented in Figure 7 are more problematic. The momentum of the rotating wind turbines provides an intrinsic ramp-down rate mitigation effect, and due to the spacing between turbines, each turbine reaches its cut-out speed independently at low wind speeds, which helps keep wind farm ramp-downs from being too extreme at wind speeds near the turbine cutout point. Still, we find that rapid wind power cut-out can result in a 25 percent reduction in wind power output within 1 minute. This occurred 0.18 percent of the hours in the NREL dataset, which translates to approximately 946 occurrences per year. Thus, in order to deliver constant output product to the system, these rapid variations must be addressed by the integrated coal-wind plant operator by ramping the linked coal plant to match wind's variability.

Wind Farm Size

Based on wind farm output characteristics and new coal plant technical capabilities, it may be possible to make estimates of how much wind capacity can be integrated with a particular coal plant. We assume, based on our research, that wind output variability and coal unit ramp rates are the predominant variables in determining wind farm size under scenarios in which the coal plant follows, and is capable of accommodating, wind output variations. We have gathered data and analyzed wind farm size based on these two variables, but there are other technical factors that could potentially affect wind farm size. These other factors are listed and briefly summarized at the end of this section.

The relationship between coal plant ramp rates and wind farm output variability provides some indication of appropriate wind farm size for the proposed GNPD project. It should be noted that the technical data suggests only a range of sizes for the wind component of the system, and the resultant overall system performance within these ranges. At this juncture there is, however, no basis for calculating the “correct” size of a wind farm.

100% Following

As stated in the beginning of this report, one of the operating scenarios being considered by GNPD is ramping the coal plant to follow all variations in wind output, creating a constant combined-system output profile. This can be called 100% following. With 100% following, if achievable, the combined system output profile should be indistinguishable from that of a stand-alone coal plant on a minute-to-minute basis.

In order for a new coal plant to follow a variable output wind farm, the wind farm capacity must be sized as a function of the maximum ramp rate of the coal plant. This wind farm size estimate methodology is based on the reasoning that as wind farm output varies, the coal plant will follow the variations within its ramping capabilities. Our estimates for 100% following, based on the NREL wind data and our coal plant ramp rate assumptions, suggest that a 500-MW coal plant would integrate well with a wind farm in the range of 20-60 MW. Scenarios under which the coal plant follows less than 100% of the wind farm output variability are considered in the following section of this paper.

Imperfect Following

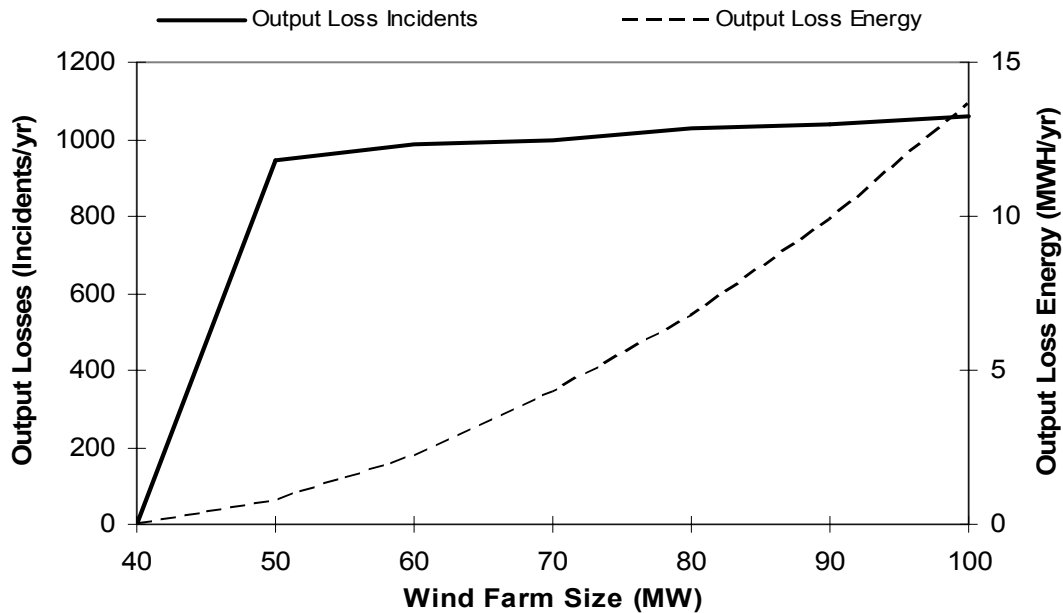
In certain cases, 100% following may not be achievable or desirable. For example, wind farm sizes larger than that allowed by 100% following may be tolerated, or actual ramp rates achievable by the coal plant may be less than our base assumption of 10 MW/minute. The ability of a coal plant to follow minute-to-minute wind output variations, which can increase one minute and decrease the next, has not been commercially demonstrated. It is possible that some lower ramp rate than our base assumption will have to be used to accommodate the type of following required by coal-wind integration.

Due to these possibilities, we explore the case of “imperfect” following, where most, but not all, variations in wind farm output are followed by the coal plant. In particular, we examine the effects of different wind farm sizes and ramp rate assumptions.

Larger wind farm sizes result in greater wind output variations, and some combined system output reductions. To examine the effects of imperfect following under a likely range of wind farm development, we examine cases from 40-100 MW.

FIGURE 8: IMPERFECT FOLLOWING: WIND FARM SIZE AND COMBINED SYSTEM OUTPUT LOSSES

Assumes 500 MW coal plant size and 10 MW/minute coal plant ramp rate



SOURCE: PLATTS

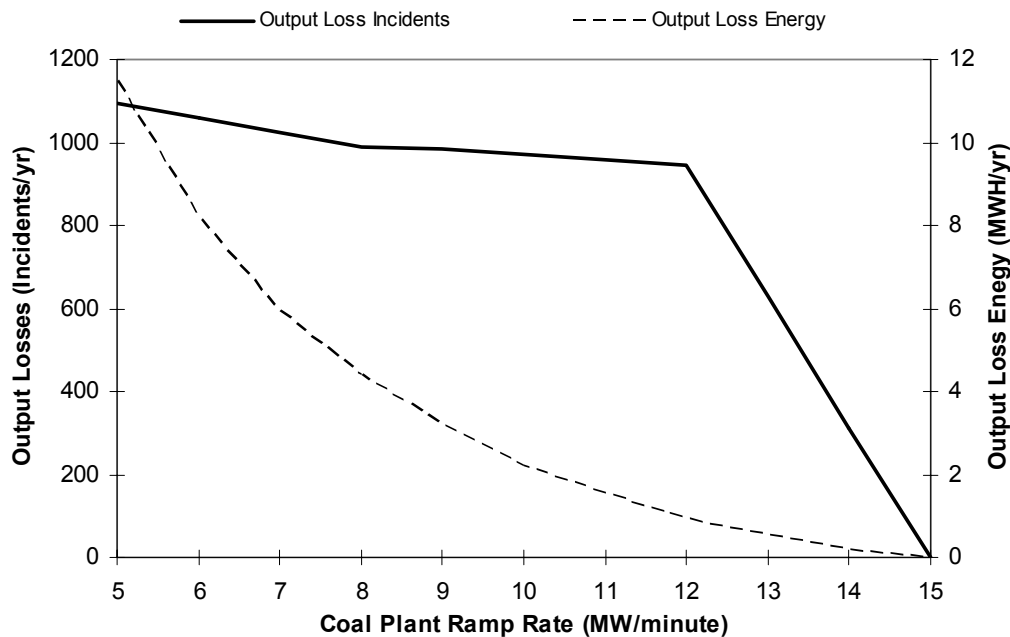
In Figure 8, as wind farm size increases beyond 40 MW, some deviations from 100% following will occur. Because wind farm upramping can be controlled to remain within a desired range, we expect these deviation incidents to take the form of temporary combined-system output losses. Above 40 MW wind farm size, combined system output losses increase, reaching approximately 1,000 minute-to-minute incidents annually at 100 MW. We estimate the magnitude of the largest combined system output losses to be about 21 MW at a 100 MW wind farm size for a 500 MW coal plant size. Despite the large number of these incidents, they do not add up to a significant loss of generation, reaching an estimated total of 14 MWH of lost combined system generation annually. The amount of lost generation is small, despite the large number of annual incidents, due to the fact that these incidents are usually only one minute in average duration.

The other major factor which could cause imperfect, versus 100%, following is coal plant ramp rate. While ramp rates ranging from 5 to 25 MW/minute have been referenced in this report, there is no assurance as to the ramp rate that will be applicable to a given unit or project, unless guaranteed by the vendor. To examine this factor, we use a 60 MW wind farm size and considered the impacts of ramp rates ranging from 5 to 15

MW/minute (a range within the extremes identified by interviewing operators of existing plants and vendors of new plants).

FIGURE 9: IMPERFECT FOLLOWING: COAL PLANT RAMP RATE AND COMBINED SYSTEM OUTPUT LOSSES

Assumes 500 MW coal plant size and 60 MW wind farm size



SOURCE: PLATTS

As shown in Figure 9, as ramp rates are decreased, the amount of variation from 100% following increases (i.e., the system losses increase). With coal plant ramp rates in the 5-12 MW/minute range, we expect roughly 1,000 system output loss incidents per year. The magnitude of the largest expected system output losses increases as ramp rate decreases, reaching about 15 MW at a 5 MW/minute ramp rate. With a 60 MW wind farm size, these variations from a constant combined system output profile do not add up to a significant loss of generation, reaching only 11 MWH lost annually at a 5 MW/minute ramp rate.

Wind Farm Size Conclusions and Caveats

We have explored two technical factors that we feel are the predominant determinants of wind farm sizing under coal-wind co-dispatch, wind farm output variability and coal plant ramp rate, but there are several other technical issues that could affect the level of wind that can be integrated with a coal-fired power plant:

Wind farm output variability:

While this study refers to the minute-to-minute variations of wind farm output, the actual real-time changes occurring over less than one minute need to be studied. Further, additional sources of data are needed to characterize minute-to-minute wind farm output variability across more than one site.

Stability of a Coal/Wind system:

Because a coal-wind system will potentially have hundreds of generating units, the stability of the combined system will need to be assured. In addition to the ability of the coal plant to follow real-time changes in a wind farm's output in the steady state, the coal plant must be able to tolerate transient events while maintaining stability.

Actual point of integration:

The point of integration for the wind and the coal will affect the ability of the combined project to supply a flat delivery. If the topology of the combined coal/wind resource does not allow for the integration of the wind prior to or very near the point of delivery for the coal output, then special arrangements that would incur additional costs will need to be established that would allow for the summation of the coal plant's output with the wind farm's output.

Transmission:

Sufficient transmission rights must be available to allow for the delivery of the entire output of the coal-fired power plant without curtailments in the delivery path. Transmission paths that are rated firm but utilize remedial action schemes will impact the deliverability of both the coal and the wind output.

The analysis performed in this section adds insight to the understanding of how coal and wind might co-dispatch in a combined system; however, without further study it is not possible to determine either the maximum or optimal amount of wind-powered generation that can be integrated with a coal-fired power plant. Further, none of the technical issues discussed in this section capture the financial effects of wind farm size. These effects of wind farm size are explored in the next section of this report.

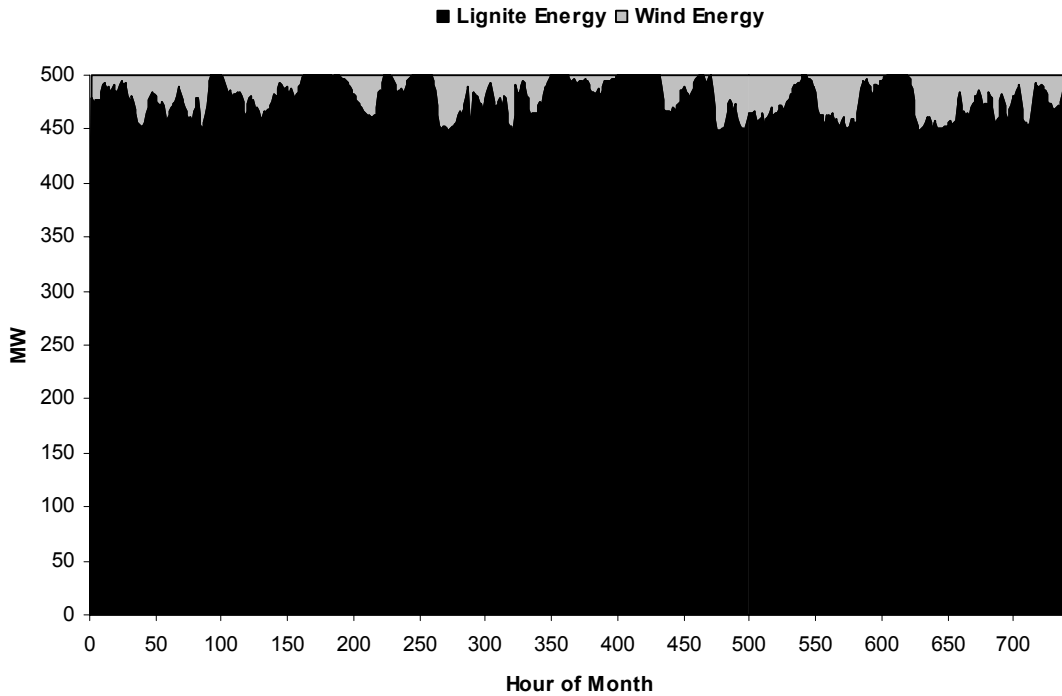
Of course, the wind farm size ultimately chosen will have a significant impact upon the wind farm's contribution to total system energy output. The impact of the wind farm size upon wind's contribution to total system energy output is illustrated in Figure 10 for a hypothetical 500 MW coal-fired plant size with 95 percent availability. We note that at a 60 MW size, wind power would account for 12% of the project capacity and between 4 and 6 percent of combined system energy output depending upon the quality of the underlying wind resource. Figure 11 illustrates the combined system output profile for a representative month, assuming a 60 MW wind farm and 100% following.

FIGURE 10: WIND FARM CONTRIBUTION TO COMBINED SYSTEM ENERGY OUTPUT

	Wind Component of Integrated System With A 500 MW Coal Plant									
Wind Farm Size (MW)	10	20	30	40	50	60	70	80	90	100
Percent Wind Capacity (%)	2%	4%	6%	8%	10%	12%	14%	16%	18%	20%
Wind Farm Capacity Factor										
20% (Class 2)	0.4%	0.8%	1.3%	1.7%	2.1%	2.5%	2.9%	3.4%	3.8%	4.2%
25% (Class 3)	0.5%	1.1%	1.6%	2.1%	2.6%	3.2%	3.7%	4.2%	4.7%	5.3%
30% (Class 4)	0.6%	1.3%	1.9%	2.5%	3.2%	3.8%	4.4%	5.1%	5.7%	6.3%
35% (Class 5)	0.7%	1.5%	2.2%	2.9%	3.7%	4.4%	5.2%	5.9%	6.6%	7.4%
40% (Class 6)	0.8%	1.7%	2.5%	3.4%	4.2%	5.1%	5.9%	6.7%	7.6%	8.4%
45% (Class 7)	0.9%	1.9%	2.8%	3.8%	4.7%	5.7%	6.6%	7.6%	8.5%	9.5%

SOURCE: PLATTS

FIGURE 11: COMBINED COAL-WIND GENERATING SYSTEM OUTPUT PROFILE (60 MW WIND FARM SIZE)



Source: Platts

Section III. The Economic & Environmental Feasibility of Coal-Wind Co-Dispatch

Now that we have a sense of the technical capability of coal fired power plants, the variability of wind farm output and an assessment of wind farm size, we move on to the consideration of the economic and environmental performance of a prospective combined coal-wind system.

Economic Performance

To evaluate economic performance of the combined coal-wind system, we examined two dispatch cases: a “max output” case, in which we assume that the coal plant operates at maximum capacity regardless of wind farm output; and a “fully integrated” case, in which we assumed 100% following with coal generation displaced when wind is available. The “max output” case assumes that enough transmission capacity is available to transmit the combined output of both wind farm and coal plant and the system operator can tolerate the wind variations in the wind farm output. The “fully integrated” case assumes that there is a finite level of transmission capacity that cannot be exceeded—defined in terms of physical or contractual capacity—and that a constant amount of electricity is continuously provided to the available transmission path.

The coal cost input assumptions are shown in Figure 12; the wind cost input assumptions are presented on the same basis in Figure 13; and the financial assumptions used in this analysis are presented in Figure 14. All economic values are presented in 2003 dollars.

FIGURE 12: COAL PLANT AND TRANSMISSION CAPACITY COST & PERFORMANCE ASSUMPTIONS (\$2003)

Plant Type	PC-Wet Cooling	CFB-Wet Cooling
On-Line Year	2008	2008
Size (MW)	500	500
Plant Capital (\$/kW)	\$1,600	\$1,733
Heat Rate (Btu/kWh)	10,070	10,140
Availability (%)	95%	95%
Fixed O&M (\$/kW-yr)	\$14.50	\$14.75
Variable O&M (\$/MWh)	\$2.06	\$2.38
Fuel Costs (\$/mmBtu)	\$0.50	\$0.50
SO ₂ Rate (lb/MWh)	1.00	1.00
NO _x Rate (lb/MWh)	0.90	0.90

SOURCE: GREAT NORTHERN POWER DEVELOPMENT

FIGURE 13: WIND FARM COST & PERFORMANCE ASSUMPTIONS (\$2003)⁶

Wind Farm Size	Small	Medium	Large
On-Line Year	2008	2008	2008
Size (MW)	25	60	250
Total Capital Cost (\$/kW)	\$1,268	\$1,100	\$900
O&M (\$/kW-yr.)	25	25	25
Capacity Factor*	35%	35%	35%

*This capacity factor is representative of Class 5 wind speed sites (that are found throughout the Upper Great Plains region) with an average annual wind speed (at 50 m) between 16.8 and 17.9 MPH.

SOURCE: PLATTS

FIGURE 14: ECONOMIC ANALYSIS FINANCIAL ASSUMPTIONS

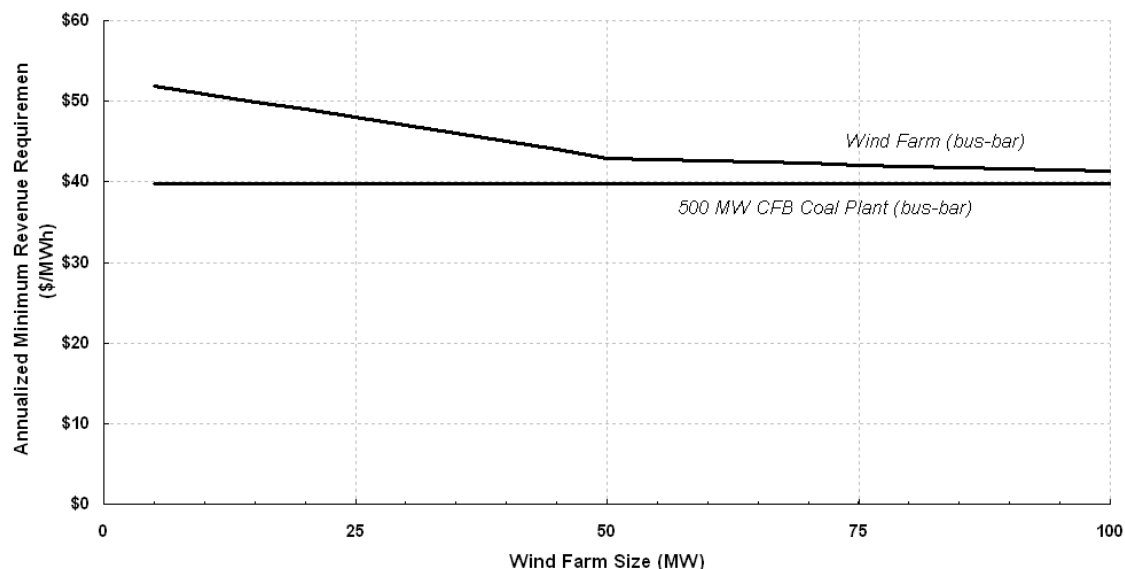
Power Purchase Agreement Escalation Rate (%)	2%
Inflation Rate	2.3%
Debt Percentage (%)	70%
Debt Interest Rate (%)	7.5%
Debt Term (years)	15
Required Minimum Debt-Service Coverage Ratio	1.5
Required Average Debt-Service Coverage Ratio	1.75
Equity Hurdle Rate (%)	15%
Combined Effective Tax Rate	40.2%

SOURCE: PLATTS

Max Output Case

The calculated minimum bus-bar revenue requirement in the “max output” case is presented in Figure 15 for a hypothetical 500 MW CFB coal plant with an on-line date of 2008 over a range of wind farm sizes. The bus-bar economics for each energy supply source are shown separately.

As shown in Figure 15, the minimum bus-bar revenue requirement for a fully-dispatched coal plant is \$40/MWh (2003 \$s), while the revenue requirement for a wind farm declines for larger wind farm sizes. Figure 15 demonstrates how the wind minimum bus-bar revenue requirement decreases as wind farm size increases, due to declining capital costs per MW that result from economies of scale in wind farm development. We estimate that the Class 5 wind farm minimum revenue requirement is approximately \$52/MWh (2003 \$s) at small system sizes, decreases to approximately \$42/MWh (2003 \$s) at 50 MW, and then decreases more slowly to \$41/MWh (2003 \$s) at a system size of 100 MW. These estimates exclude consideration of the 1.8 ¢/kWh (\$18/MWh) 10-year federal PTC that expired at the end of 2003, but is expected to be renewed for 3 years in 2004. The impact of the PTC on wind farm economics is discussed in more detail later in this section.

FIGURE 15: MAX OUTPUT CASE - WIND AND COAL MINIMUM REVENUE REQUIREMENTS

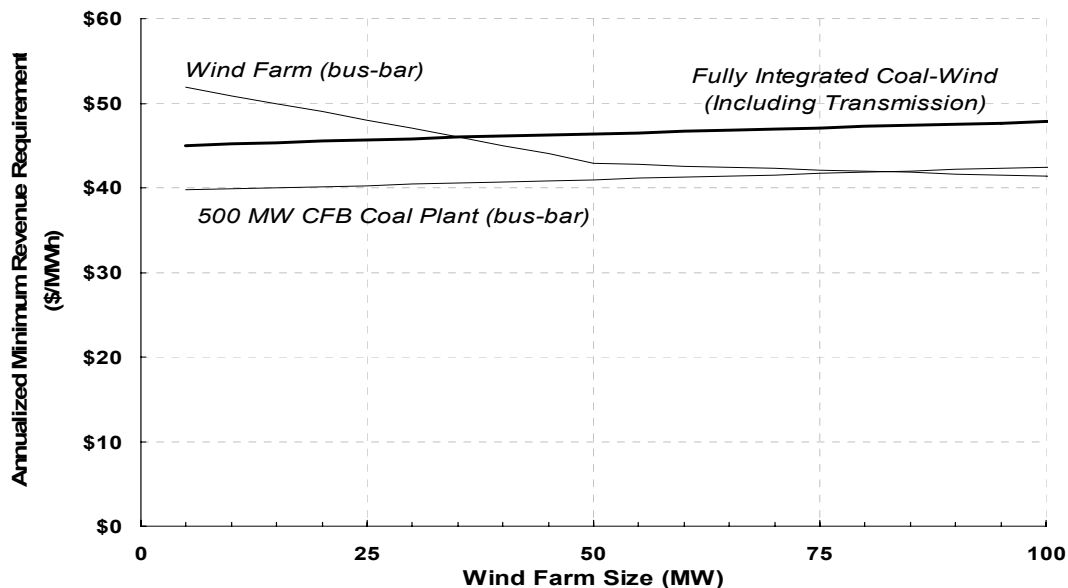
SOURCE: PLATTS

Fully Integrated Case

The results for the fully integrated case are presented in Figure 16, which shows minimum bus-bar revenue requirements for the wind farm and coal-fired generation over a range of wind farm sizes. Figure 16 also shows the integrated (i.e., coal and wind) system cost, which includes a charge of \$200 million (or \$400/kW) for transmission capacity additions to accommodate the delivery of energy from a remotely located 500 MW project in the Upper Great Plains. Such expense translates to a transmission charge or tariff of about \$5.50/MWh (\$3.75/kw-mo) – a rate that is consistent with regional firm transmission tariffs to load centers.

Under co-dispatch, the coal plant reduces output as wind farm size and output increases, producing a constant combined system output stream. As illustrated in Figure 16, co-dispatch thus lowers the capacity factor of the coal plant as the wind farm size increases, increasing the coal plant minimum revenue requirement as a result of spreading the coal plant investment over decreasing amounts of coal-fired energy generation. This increases the minimum revenue requirement for progressively higher amounts of wind incorporated as reflected in the combined economics of co-dispatching the two power resources, inclusive of transmission.

FIGURE 16: FULLY INTEGRATED CASE - BUS-BAR AND INTEGRATED MINIMUM REVENUE REQUIREMENTS



SOURCE: PLATTS

As one might expect, the gradual increase in coal plant minimum revenue requirement with increasing levels wind farm capacity has a negative effect on the overall project's rate of return, expressed here as internal rate of return (IRR). This is illustrated for a hypothetical 500 MW Upper Great Plains coal-wind project, inclusive of transmission costs, in Figure 17. For illustrative purposes, in Figure 17, we show the project IRR as a function of wind farm size assuming 100% following co-dispatch at three different lifecycle average revenue levels: \$40, \$45 and \$50/MWh. As these curves show, the system IRR declines by 1 percent for each 30 MW of additional wind farm capacity.⁷⁸

This highlights another important constraint on the wind farm size. Even if it is technically feasible to co-dispatch at large wind farm sizes, it is not financially feasible if the combined system rate of return is below the equity investor hurdle rate. Investors are likely to tolerate some level of IRR reduction to include wind capacity, but at high levels of wind capacity, the IRR may erode to unacceptable levels. Ultimately, this level is a function of the investor's opportunity cost of capital and tolerance for risk. However, the bottom line is clear: when it comes to coal-wind co-dispatch, economic feasibility is as important as technical feasibility.

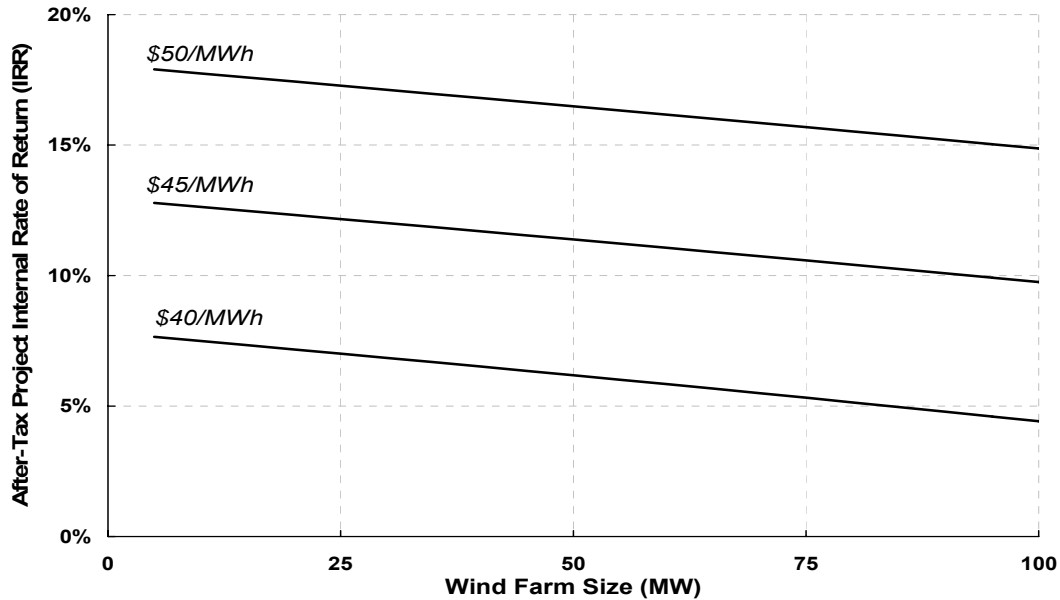
The viability of an integrated coal-wind project will be extremely sensitive to the amount of wind capacity. However, such sensitivity can be mitigated to some extent by high quality wind resources and federal policy support for wind energy, both of which will

⁷ When integrated with overall project returns, the cost-reducing effect of economies of scale for >50 MW wind farm sizes is not readily discernable at the scale shown on Figure 17.

⁸ Another metric used to determine profitability is the Modified Internal Rate of Return (MIRR). The MIRR assumes that all positive cash flows are reinvested at the firm's reinvestment rate, while IRR implicitly assumes the positive cash flows are reinvested at the project IRR. PR&C's calculations for this project indicate that system MIRR declines by 1 percent for each 60 MW of additional wind farm capacity.

reduce the cost of wind energy and/or improve the integrated coal-wind project rate of return. These issues are addressed next.

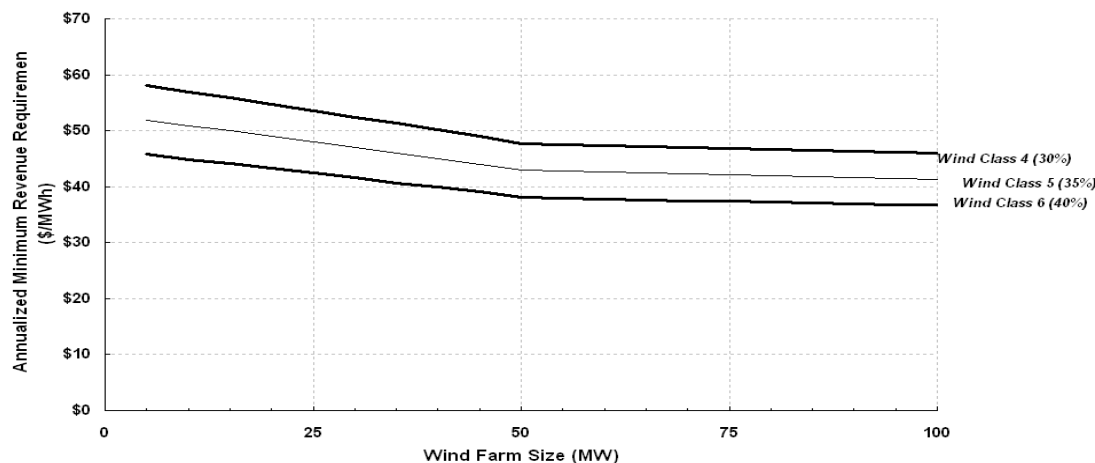
FIGURE 17: FULLY INTEGRATED CASE – INTERNAL RATE OF RETURN ANALYSIS FOR THREE POWER MARKET PRICE SCENARIOS



SOURCE: PLATTS

Wind Resource Quality

Although the Upper Great Plains contains vast quantities of high-quality wind resources, these resources are unevenly distributed, and the best resources are often located in areas that are not appropriate for transmission line extension, or coal-fired power plant development. As a result, the average annual capacity factor at wind farm sites that are suitable for joint coal and wind power development varies widely. Because even a 1 percent difference in wind capacity factor can have a significant impact on wind farm economics, it is useful to explore the impact of this key factor. In Figure 18, we show the impact of alternative wind resource quality assumptions on wind farm economics.

FIGURE 18: THE IMPACT OF WIND RESOURCE QUALITY ON WIND FARM ECONOMICS

SOURCE: PLATTS

Impact of the Production Tax Credit

Wind farm economics are significantly impacted by the presence of the 1.8 ¢/kWh (\$18/MWh) 10-year federal PTC that has been available to wind power plant owners. The PTC was originally enacted as part of the Energy Policy Act of 1992 and has been repeatedly extended as a result of its success in increasing the market adoption of wind power. The credit expired at the end of 2003, but it is likely that the PTC will be extended for 3 years in 2004.

If the credit is indeed extended, it is our view that the PTC will not be extended again after the December 2006 expiration. Given the high level of wind capacity that we expect to enter the market over the next several years in response to new state-level renewable portfolio standards (RPS), we believe that the federal government will not have the appetite to extend a credit that will cost the U.S. Treasury \$466 million per year by 2006. This is only speculation of course, and energy sector stakeholders have historically demonstrated a remarkable ability to keep the governmental subsidies flowing long after they have accomplished their original objective.

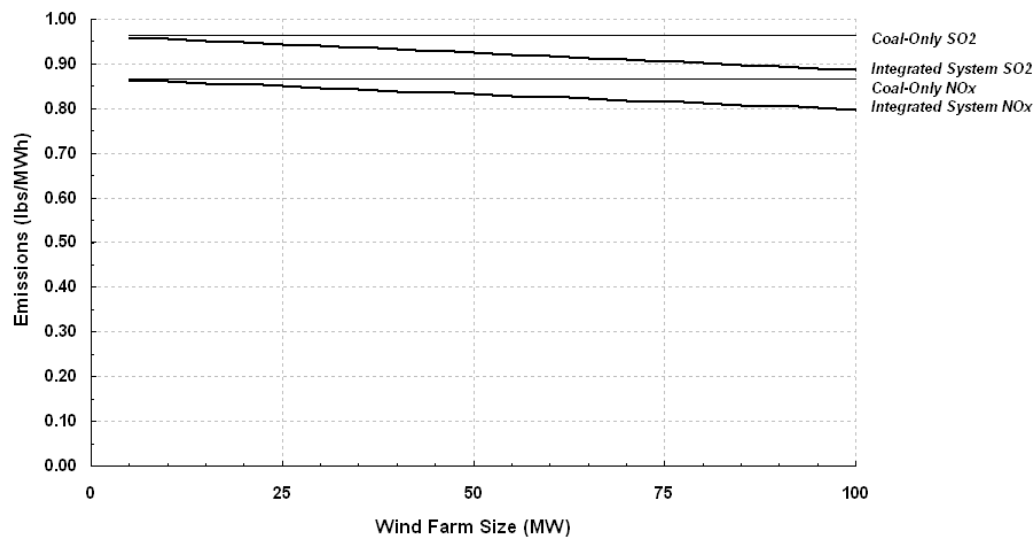
If the credit is indeed available in 2008, it will have a significant economic impact on wind project economics. Depending upon project structure, the PTC will either: (1) reduce the minimum annualized revenue requirement (i.e. the cost of wind power); (2) increase the project's rate of return (and by extension the combined coal-wind system rate of return in the context of a joint project); or a combination of both. In any case, the result will be positive for the viability of integrated coal-wind in the Upper Great Plains since a reduced annualized revenue requirement will improve market competitiveness of the joint project and an increased rate of return will increase the amount of wind capacity

that can be added to the project without pushing the combined project IRR below the project developer's hurdle rate.

Environmental Performance

One of the advantages of linking a coal-fired power plant with a wind farm is to improve the environmental performance of the joint power system relative to the stand-alone coal project. These environmental benefits are illustrated in Figure 19, which shows SO₂ and NO_x emissions rates for the stand-alone coal plant and fully integrated system over a range of wind farm sizes.

FIGURE 19: FULLY INTEGRATED VS. STAND-ALONE ENVIRONMENTAL PERFORMANCE



SOURCE: PLATTS RESEARCH & CONSULTING

Our environmental analysis shows that SO₂ and NO_x from a new hypothetical 500 MW CFB coal plant equipped with required pollution control equipment will decrease proportionate to the amount of coal-fired generation displaced by wind generation. In this case, the subject emissions will decrease by 1 percent for every 13.6 MW of wind capacity incorporated into the project. Though not illustrated or calculated herein, an identical relationship can be expected for CO₂ emissions.