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MEMORANDUM

TO:	Interested Parties
FROM:	WPPI Energy
DATE:	March 10, 2010
SUBJECT:	**Burns & McDonnell Transmission / Wind Economics Study and Model Produced for WPPI Energy**

Burns & McDonnell Engineering Company (BMcD) recently completed a project for WPPI Energy (WPPI) which we would like to share with you for two reasons:

1. We anticipate it will be a helpful conceptual tool and reference for you as our industry considers the feasibility of transmitting renewable energy to load centers from remote wind generators.

2. We are interested in any suggestions you may have about the model or observations regarding its applicability to the transmission planning studies underway in the Eastern Interconnection (e.g., RGOS, SMART, EIPC).

WPPI asked BMcD to first estimate what capacity factors one could expect for wind generators located in various states within the MISO and PJM footprints (see Figure 3-2). Second, we wanted to know how the busbar cost of a wind generator varies with capacity factor (see Figure 4-2). Finally, we wanted to know how much one could justifiably spend on transmission (specifically on power transfer capability) to import wind energy from wind rich areas (see Figure 5-1). Thus, the study and the model provide an indication of whether it is better to site wind generators in rich wind areas and build transmission to deliver it, or simply site the wind generators close to load, even though the wind resource may be inferior.

Based upon our review of the study, we conclude that assuming the region should pursue a renewable energy strategy that relies primarily upon highly concentrated wind resources may not result in the most cost effective solution. We further conclude that it therefore is difficult to justify 765 EHV overlay investment at this time to support highly concentrated wind development. Finally, we conclude that a "no regrets" incremental approach to expanding the existing 345 kV backbone, as is under consideration by UMTDI among others, is likely of higher economic merit and lower risk.

This is not meant to be a definitive test on the economic merits of a particular transmission line. We believe it provides useful information as an initial economic screening tool for transmission planners, regulators and MISO stakeholders to better understand the economic tradeoffs between remote generation and more geographically dispersed generation. This report does not consider the range of other economic benefits from additional transmission capacity, such as reducing congestion costs and increasing transfer capability to import or export cheaper power. In addition, the report does not quantify the direct economic benefits associated with transmission line construction or the potential benefits associated with system loss savings resulting from new transmission investment. Nor does it attempt to quantify the range of other economic benefits associated with more geographically dispersed generation, i.e. job creation, tax base, etc.

To illustrate how one can use the study, consider the desirability of transmitting wind energy from North Dakota to Ohio. The study indicates a capacity factor differential between North Dakota and Ohio of about 13.2 percentage points. The study further indicates that, based on this capacity factor differential, one could economically justify $720/kW in transmission investment cost to deliver the energy from North Dakota to Ohio. If it costs more than $720/kW to provide transfer capability to deliver such energy, it would be less expensive to simply build the wind farms close to load in Ohio. If our understanding of current transmission planning results is correct, it is generally more expensive (than this breakeven indication) to build additional power transfer capability over such a long distance. There may be other reasons that could justify such a build-out, but capacity factor differential alone does not.

The study also allows one to quickly calculate transmission breakeven investments from other states. For instance, if transmission planning studies indicate that building transfer capability between North Dakota and Ohio costs $1,000/kW, one may conclude that this would not be an economic action (because it exceeds the breakeven transmission investment cost). But what about importing from someplace closer instead (e.g., Illinois)? The differential wind capacity factor between Illinois and Ohio is approximately 5% (from Figure 3-2). This would justify approximately $300/kW of transmission investment (from Figure 5-1). While the breakeven transmission cost has dropped relative to North Dakota, Illinois is a lot closer to Ohio than North Dakota is and building this level of transfer capability may be more feasible as a result.

An additional economic factor that should be noted is that the study assumes that the purchaser incurs no incremental LMP congestion costs to deliver such wind energy. This would only occur if the purchaser of the wind energy is also entitled to the FTR revenue for the incremental transfer capability constructed to accommodate such wind energy. This is an optimistic assumption since the current MISO ARR/FTR process does not automatically provide annual FTRs to the entity paying for the incremental transfer capability.

Any comments or observations you have about the study or model would be much appreciated. Please direct your comments to Tim Noeldner at 608-220-1263 or tnoeldner@wppienergy.org.

Wind Energy Transmission Economics Assessment

Prepared For

WPPI Energy

March 2010

Project 55056

Wind Energy Transmission Economics Assessment

prepared for

WPPI Energy
Sun Prairie, Wisconsin

March 2010

Project No. 55056

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS AND ACRONYMS

BMcD	Burns & McDonnell Engineering Company, Inc.
DOE	Department of Energy
GE	General Electric
GIS	Geographic Information System
IEC	International Electrotechnical Commission
ITC	Investment Tax Credit
kW	kilowatt
m	meters
m/s	meters per second
MISO	Midwest Independent Transmission System Operator
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Reliability Corporation
NREL	National Renewable Energy Laboratory
PJM	PJM Interconnection
PTC	Production Tax Credit
RTO	Regional Transmission Organization
Study	Wind Energy Transmission Economics Assessment
WPPI	WPPI Energy

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SECTION 1

EXECUTIVE SUMMARY

1.0 EXECUTIVE SUMMARY

Burns & McDonnell Engineering Company (BMcD) was retained by WPPI Energy (WPPI) to perform a Wind Energy Transmission Economics Assessment (Study). The purpose of the Study was to assist WPPI with the development of an economic model to assess the viability of transporting wind energy from wind-rich areas in the northern United States to eastern load centers. As part of this evaluation, WPPI was interested in obtaining a tool that would address the following question:

> **Is it more economically viable to (i) develop wind projects in wind-rich areas and construct the necessary electric transmission infrastructure to transfer energy from those projects to load centers; or (ii) develop wind projects near the load centers despite a less attractive wind resource in those locations?**

The economic model produced by this Study enables its user to derive the breakeven amount that can economically be spent on transmission improvements required to move wind energy from one area to another. This breakeven amount, expressed in dollars per kilowatt of incremental power transfer capability, is calculated as the difference in levelized busbar generation cost between a wind farm with a high capacity factor and a similar wind farm in a location with a low capacity factor. The user of the economic model may subsequently assess the economic feasibility of developing remote wind generation by comparing the breakeven cost with their projected cost of providing incremental power transfer capability between the two areas. Note that this Study does not estimate expected congestion cost savings that new transmission facilities would provide at other times.

The Study was completed as three separate tasks:

1. The first task was a characterization of regional capacity factors from wind resources throughout different areas of the United States. These areas primarily included states within the MISO and PJM regional transmission organization footprints. See Figure 3-2 for results from this task
2. The second task was the preparation of an economic model to evaluate the relative financial viability of developing wind resources in assorted areas of the country. Figure 1-1 below presents the approximate 30-year levelized busbar cost (2014$) as a function of capacity factor.
3. The third and final task was an evaluation of electric transmission system breakeven capital cost. The breakeven cost is the electric transmission capital investment that can be economically

justified by the differential in capacity factors between potential source and sink Project locations. Figure 1-2 below presents the breakeven cost as a function of capacity factor differential.

Figure 1-1: Levelized Busbar Cost Variation with Net Annual Capacity Factor

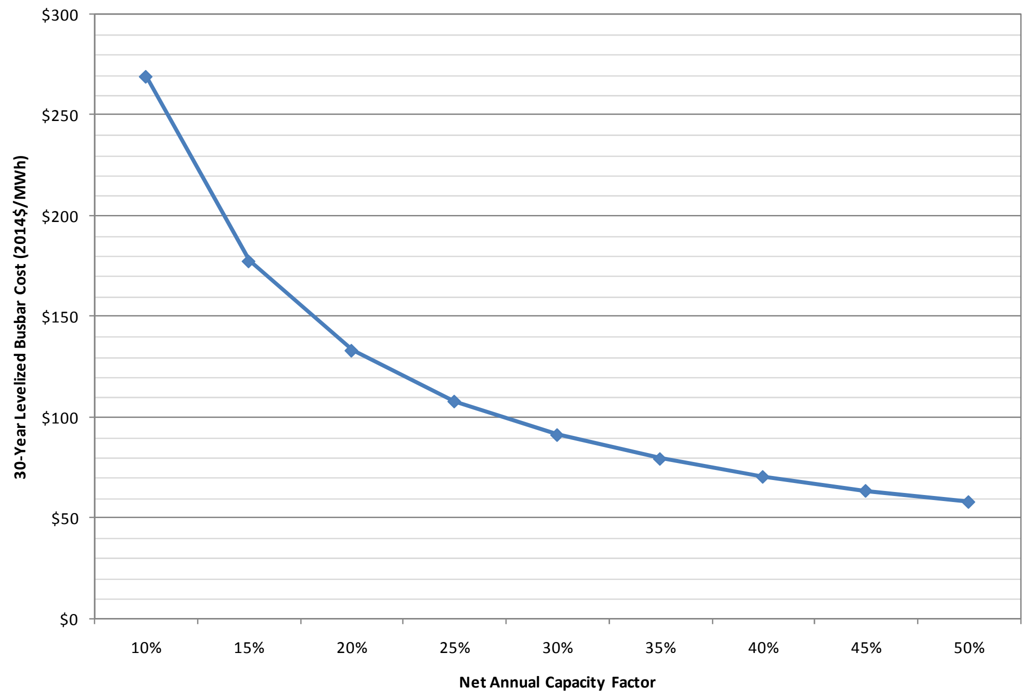
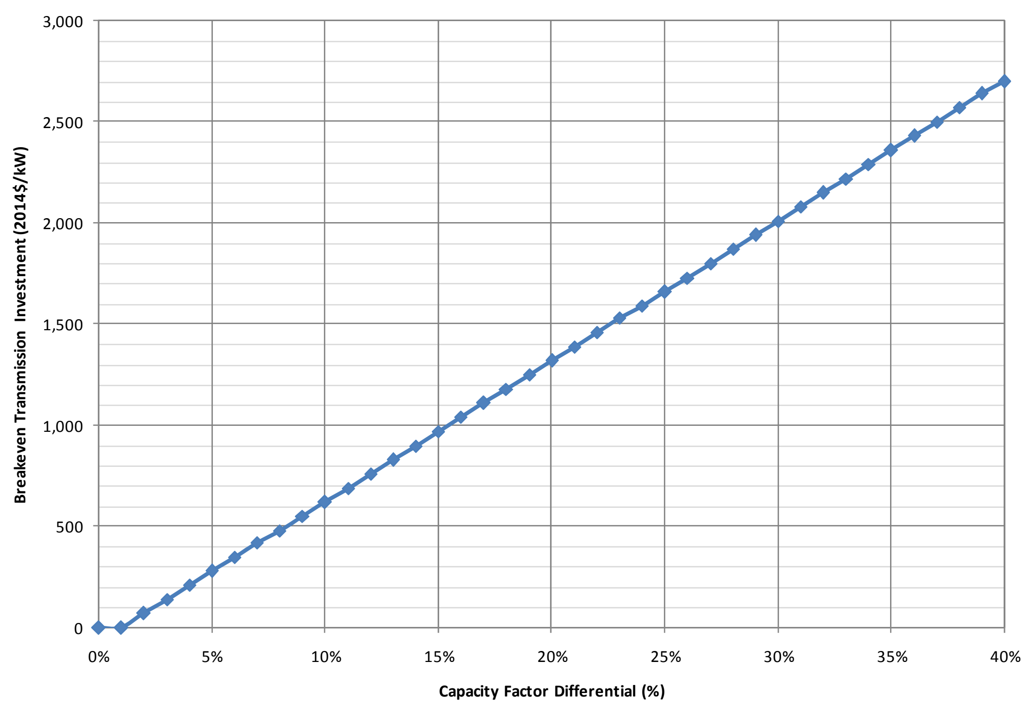


Figure 1-2: Breakeven Transmission Capital Cost by Capacity Factor Differential



Utilizing the capacity factor ranges (Task 1) and pro forma economic model (Task 2), BMcD determined the electric transmission system capital cost investment that could be economically justified for moving wind energy between various Project locations. Assuming a relatively large capacity factor differential of 20 percentage points between the source and sink locations, the breakeven transmission investment was estimated at $1,320 per kilowatt. Thus, a project sited in a wind-rich area could justifiably spend up to $1,320 per kilowatt of incremental power transfer capability and remain economically competitive with a similar project sited in an area with an annual capacity factor that is 20 points lower.

The amount of transmission investment that an entity could economically justify to provide the required capability to transfer wind energy decreases as the differential in capacity factor narrows. For instance, assuming a differential of 13.2 percent between North Dakota and Ohio, the breakeven transmission cost was determined to be approximately $720 per kilowatt. Thus, if an entity was interested in transferring energy from a 1,000-megawatt wind farm in North Dakota to loads in Ohio, the capacity factor differential between these states would economically justify spending up to $720 million on transmission system improvements ($720/kW x 1,000 MW x 1,000 kW/MW = $720 million). As such, if transmission planning studies indicate that it would cost $2 billion to provide 1,000 megawatts of incremental power transfer capability from North Dakota to Ohio, for example, the Study would show that siting the subject wind generation locally in Ohio would be more economic.

* * * * *

SECTION 2

INTRODUCTION

2.0 INTRODUCTION

Burns & McDonnell Engineering Company (BMcD) was retained by WPPI Energy (WPPI) to perform a Wind Energy Transmission Economics Assessment (Study). The purpose of the Study was to assist WPPI with the development of an economic model to assess the viability of transporting wind energy from wind-rich areas in the northern United States to eastern load centers (Project).

The Study was completed as three separate tasks:

1. The first task was a characterization of regional capacity factors from wind resources throughout different areas of the United States. These primarily included states within the Midwest Independent Transmission System Operator (MISO) and PJM Interconnection (PJM) regional transmission organization (RTO) footprints.
2. The second task was the preparation of an economic model to evaluate the relative financial viability of developing wind resources in assorted areas of the country.
3. The third and final task was an evaluation of electric transmission system capital cost investments required to move wind energy between potential Project locations.

The following sections present an overview of the methodology and assumptions used to complete the Study, as well as conclusions reached as part of the Study.

* * * * *

SECTION 3

REGIONAL CAPACITY FACTOR CHARACTERIZATION

3.0 REGIONAL CAPACITY FACTOR CHARACTERIZATION

A significant and underlying assumption of the Project is that wind energy will be harnessed in areas with attractive wind resources and delivered to more modest wind-resource locations. Moreover, perhaps the most influential factor on the economics of a wind energy project is that project's capacity factor. Thus, it is important to characterize the expected capacity factor ranges that are likely to occur between various Project locations. The following sections detail the methodology utilized in the characterization of regional capacity factors for the Study.

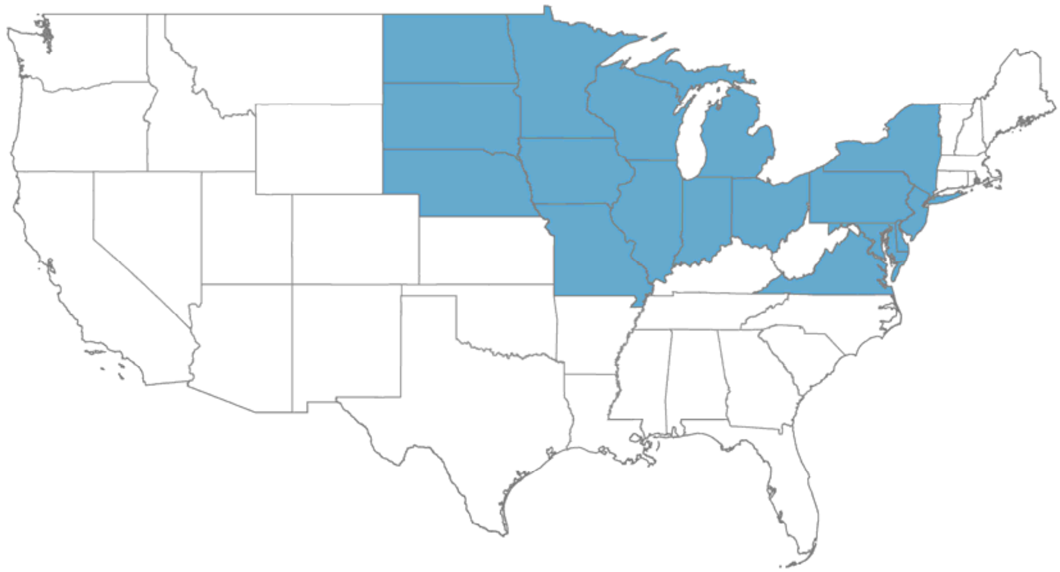
3.1 PROJECT LOCATIONS

For purposes of this Study, multiple locations throughout the North American Reliability Corporation (NERC) Eastern Interconnection were considered as potential wind-energy source and/or sink areas for the Project:

- Delaware
- Illinois
- Indiana
- Iowa
- Maryland
- Michigan
- Minnesota
- Missouri
- Nebraska
- New Jersey
- New York
- North Dakota
- Ohio
- Pennsylvania
- South Dakota
- Virginia
- Wisconsin

These locations, shown graphically in Figure 3-1 below, are examined in further detail in subsequent sections.

Figure 3-1: Potential Project Locations



3.2 WIND RESOURCE DATA

BMcD relied exclusively upon publically-available data to complete the regional capacity factor characterization task. More specifically, high-resolution wind density maps from the Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) and Wind Powering America program were utilized to generate the statewide capacity factor ranges. These maps depict classes of wind power density at both 10 meters and 50 meters above the ground. A sample of a 50-meter NREL wind density map is included in Appendix A for reference.

Wind density maps from NREL include a range of mean annual wind speeds for each wind power class. Table 3-1 below presents a summary of the seven wind power classifications, the resource potential of each, and the 10- and 50-meter mean annual wind speed ranges designated by NREL.

Table 3-1: Wind Classifications at 10 meters and 50 meters

Wind Power Class	Resource Potential	Wind Speed at 10m (m/s)			Wind Speed at 50m (m/s)		
		Low	Mid-Range	High	Low	Mid-Range	High
1	Poor	0.0	2.2	4.4	0.0	2.8	5.6
2	Marginal	4.4	4.8	5.1	5.6	6.0	6.4
3	Fair	5.1	5.4	5.6	6.4	6.7	7.0
4	Good	5.6	5.8	6.0	7.0	7.3	7.5
5	Excellent	6.0	6.2	6.4	7.5	7.8	8.0
6	Outstanding	6.4	6.7	7.0	8.0	8.4	8.8
7	Superb	7.0	8.2	9.4	8.8	10.4	11.9

3.3 VERTICAL EXTRAPOLATION OF WIND SPEEDS

Wind turbines typically feature hub heights between 80 and 100 meters above the ground. Because of vertical wind shear, or the variation in wind speed with elevation, it is important to evaluate wind speeds at the machine's hub height rather than the lower-elevation data offered by NREL.

For this Study, BMcD assumed an 80-meter hub height. Wind speeds for each power class were vertically extrapolated to 80 meters by assuming a power law profile with a shear exponent (α) of 1/7, or approximately 0.143. Table 3-2 below details the mean annual hub-height wind speeds assumed for each wind power class.

Table 3-2: Wind Classifications at 80m

Wind Power Class	Resource Potential	Wind Speed at 80m (m/s)		
		Low	Mid-Range	High
1	Poor	0.00	2.99	5.99
2	Marginal	5.99	6.42	6.84
3	Fair	6.84	7.17	7.49
4	Good	7.49	7.75	8.02
5	Excellent	8.02	8.29	8.56
6	Outstanding	8.56	8.98	9.41
7	Superb	9.41	11.07	12.73

3.4 STATEWIDE ELEVATION ADJUSTMENTS

Mean annual wind speeds from NREL are based upon standard sea-level conditions. To maintain an equivalent power density at varying elevations, wind speeds were increased by one percent per 1,000 feet in elevation. Elevations for each potential source and sink location were extracted from the 2000 U.S. Census report and represent mean, statewide elevation values. Table 3-3 below presents the mean elevation for each state and the net adjustment made to mean annual wind speeds.

Table 3-3: Mean Annual Wind Speed Adjustment Values

State	Mean Elevation (feet)	Adjustment (%)
Delaware	500	0.50%
Iowa	700	0.70%
Illinois	600	0.60%
Indiana	700	0.70%
Maryland	350	0.35%
Michigan	900	0.90%
Minnesota	1,200	1.20%
Missouri	800	0.80%
North Dakota	1,900	1.90%
Nebraska	2,600	2.60%
New Jersey	250	0.25%
New York	1,000	1.00%
Ohio	850	0.85%
Pennsylvania	1,100	1.10%
South Dakota	2,200	2.20%
Virginia	950	0.95%
Wisconsin	1,050	1.05%

3.5 STATE CAPACITY FACTOR RANGES

To compile representative capacity factors, BMcD first analyzed the distribution of each wind power class by state. High-resolution data layers from NREL were imported into geographic information system (GIS) software to compute the percentage of land area represented by each wind power class. Using the 80-meter mean annual wind speeds noted in Table 3-2 and the elevation adjustments noted in Table 3-3, a weighted-average wind speed range was computed for each state based on the aforementioned wind class distributions. Only land-based wind power classes were considered; all offshore wind resources were excluded from consideration. A summary of the weighted mean annual wind speeds for each potential source/sink location is included in Table 3-4 below.

It is important to note that class 3 and above wind density areas are typically considered suitable for developing utility-scale wind farms. Although wind projects have been successfully developed at class 2 and below areas, these are typically not as attractive as those with more significant wind resources. For purposes of this Study, class 1 wind density areas were excluded from consideration. Class 2 wind density areas were retained in order to not unduly bias results in states with predominantly weaker overall wind resources.

Table 3-4: Mean Annual Wind Speeds Weighted by Wind Power Class

State	Mean Annual Wind Speeds (m/s)		
	Min	Avg	Max
Delaware	6.32	6.72	7.11
Illinois	6.54	6.90	7.27
Indiana	6.09	6.52	6.94
Iowa	7.02	7.33	7.65
Maryland	6.14	6.55	6.97
Michigan	6.22	6.64	7.05
Minnesota	7.09	7.43	7.77
Missouri	6.04	6.48	6.91
Nebraska	6.96	7.31	7.65
New Jersey	6.21	6.61	7.01
New York	6.19	6.61	7.02
North Dakota	7.19	7.51	7.82
Ohio	6.06	6.49	6.92
Pennsylvania	6.18	6.60	7.02
South Dakota	7.50	7.81	8.12
Virginia	6.13	6.55	6.97
Wisconsin	6.27	6.67	7.08

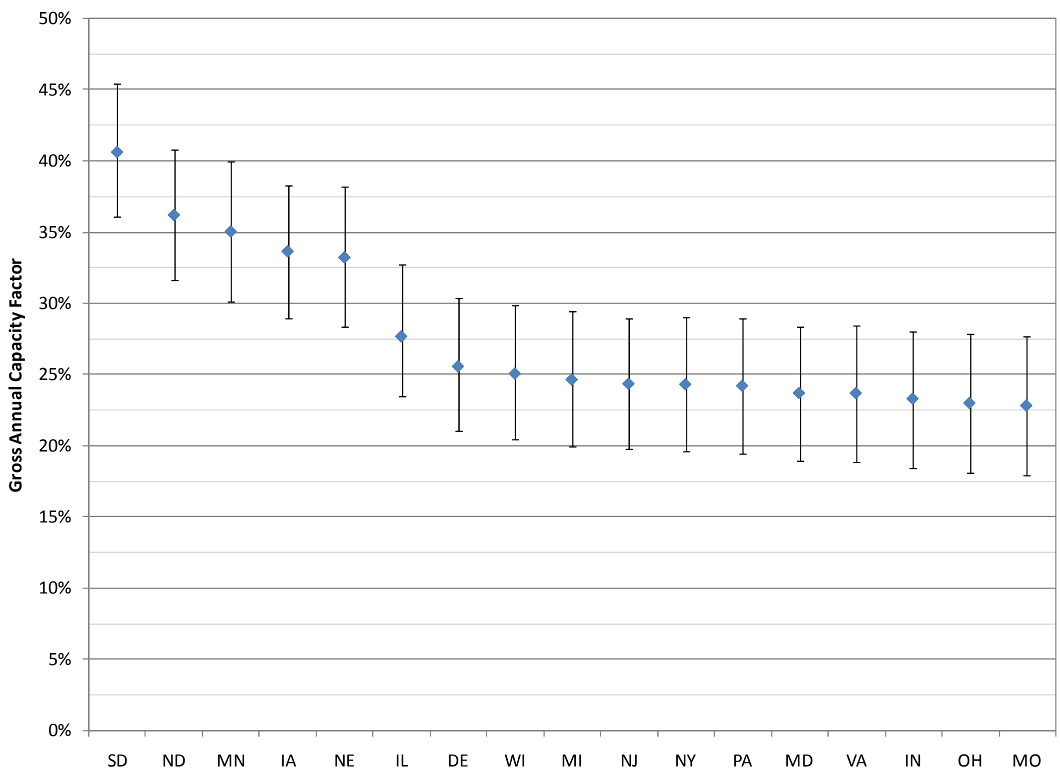
Using the mean annual wind speeds noted above, a range of expected capacity factors was developed for each state. These capacity factors were based on a generic wind turbine technology with a nameplate capacity of two megawatts (MW) and a hub height of 80 meters. A composite power curve was utilized for the assumed turbine by normalizing and averaging the curves from various General Electric (GE), Vestas, and Gamesa International Electrotechnical Commission (IEC) Class II wind turbines.

A summary of the gross annual capacity factor range for each potential state is included in Table 3-5 below. This same information is presented graphically in Figure 3-2. As can be seen in the information below, the highest mean annual capacity factors typically occur in the northern and upper-Midwest states whereas the lowest mean annual capacity factors typically occur in eastern and northeastern states.

Table 3-5: Gross Annual Capacity Factors by State

State	Gross Annual Capacity Factor Range		
	Min	Avg	Max
Delaware	21.1%	25.5%	30.4%
Illinois	23.5%	27.6%	32.7%
Indiana	18.5%	23.3%	28.1%
Iowa	29.0%	33.6%	38.3%
Maryland	19.0%	23.7%	28.4%
Michigan	19.9%	24.6%	29.4%
Minnesota	30.1%	35.0%	40.0%
Missouri	17.9%	22.8%	27.7%
Nebraska	28.3%	33.2%	38.2%
New Jersey	19.7%	24.3%	28.9%
New York	19.6%	24.3%	29.0%
North Dakota	31.6%	36.2%	40.8%
Ohio	18.1%	23.0%	27.8%
Pennsylvania	19.4%	24.2%	29.0%
South Dakota	36.1%	40.6%	45.4%
Virginia	18.9%	23.7%	28.4%
Wisconsin	20.4%	25.0%	29.9%

Figure 3-2: Gross Annual Capacity Factors by State



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SECTION 4

PRO FORMA ECONOMIC ANALYSIS

4.0 PRO FORMA ECONOMIC ANALYSIS

BMcD prepared a pro forma economic analysis to evaluate the 30-year levelized busbar cost of the Project. The levelized busbar cost represents the fixed energy cost that would be equivalent to an annually escalated busbar cost over a 30-year period. The pro forma model is based on a generic Project site and incorporates expected costs for a utility-scale wind farm, including typical capital costs, debt service expenses, tax liabilities and credits, and operating costs.

4.1 PRO FORMA INPUTS

The pro forma model was designed and delivered to WPPI with the intention of allowing for the modification of all model inputs. The following estimates and economics assumptions were utilized as base-case values in the model:

- Operational Assumptions
  - Net Output 100,000 kW
  - Annual Net Capacity Factor 38.00%
  - Commercial Operation Date 2014
- Financing Assumptions
  - Debt Interest Rate 6.00%
  - Debt Financing Term 20 years
  - Capital Structure Debt – 70%, Equity – 30%
  - Required Return on Equity 12.00%
  - Construction Financing Fees 0.50%
  - Permanent Financing Fees 1.00%
  - Minimum Debt Service Coverage Ratio 1.25
  - Debt Service Reserve Funding None
- Economic Assumptions
  - General Escalation Rate 2.50% per annum
  - Discount Rate 7.80%
  - Sales Tax Rate 0.00%
  - Income Tax Rate 35.00%
- Depreciation Assumptions
  - Straight-Line Book Depreciation Term 30 years

- Capital Cost Assumptions
  - Capital Cost Estimate (2010$) $2,000/kW
- O&M Cost Assumptions
  - Fixed O&M Costs (2010$) $10.50/kW-year
  - Variable O&M Costs (2010$) $6.00/MWh
  - Property Tax Rate 0.00%
  - Insurance Rate 0.05%
- Renewable Tax Credits
  - Production Tax Credit Value (2009$) $0.021/kWh
  - Production Tax Credit Escalation Rate 2.00%
  - Investment Tax Credit Value 30.00%

These assumptions are based upon typical values observed for utility-scale wind farms and BMcD's experience with developing comparable projects. The following highlights a few of the most important pro forma inputs and the methodology used to derive these numbers:

- **Commercial Operation Date:** A date of 2014 was assumed as the earliest and most aggressive date available to become commercially operable for a wind project not currently under development.
- **Sales Tax Rate:** To encourage the development of renewable energy, many states offer a sales tax exemption for in-state wind farms.
- **Property Tax Rate:** To encourage the development of renewable energy, many states offer a property tax exemption for in-state wind farms.
- **Capital Cost Estimate:** The capital cost estimate of $2,000/kW is based upon analysis of four turbine supply agreements from late 2009. The average cost of these contracts was approximately $1,500/kW and included all turbines, delivery, installation, and commissioning activities. Because wind turbines typically constitute approximately 75 percent of the overall project capital cost (with remaining costs being associated with the power collection system, access roads, foundations, owner's costs, etc.), a value of $2,000/kW was assumed for this analysis.
- **O&M Cost Assumptions:** The base values are consistent with a July 2008 report from the DOE entitled *20% Wind Energy by 2030*.
- **Renewable Tax Credits:** The pro forma model allows for the production tax credit (PTC) or investment tax credit (ITC) to be utilized by the Project. These credits cannot be used

simultaneously and no tax credit is required to be utilized. However, the model does assume that both credits will be available at the Project's COD. Moreover, as part of the American Recovery and Reinvestment Act of 2009, a cash grant of up to 30 percent of the cost of building a new facility is available for certain renewable energy projects built in 2009 or 2010. The pro forma model assumes that this grant will not be available beyond these years.

4.2 PRO FORMA RESULTS

Utilizing the base assumptions noted above, the 30-year levelized busbar cost of the Project was estimated to be $73.62 per MWh (2014$). In current (2010) dollars, this would be approximately $68.01 per MWh. This cost is in line with BMcD expectations and experience, as well as a report recently published by NREL entitled *Wind Levelized Cost of Energy* (October 2009).

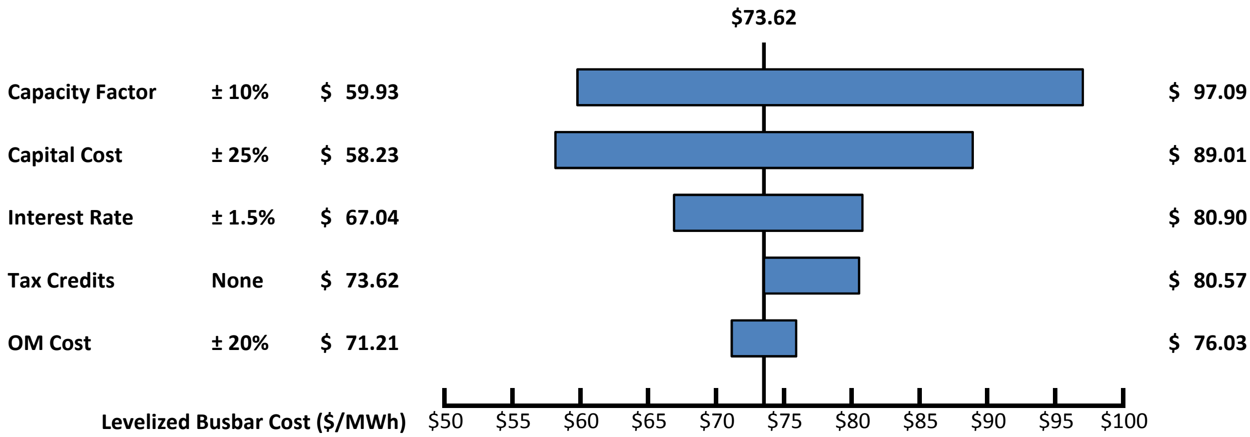
4.3 BUSBAR COST SENSITIVITY ANALYSIS

To understand the impacts of the economic inputs on the results of the busbar cost evaluation, a sensitivity analysis was prepared for the following cases:

- Capital Cost ± 25%
- O&M Costs ± 20%
- Capacity Factor ± 10%
- Interest Rate ± 1.5 percentage points
- No Federal Tax Incentives (PTC, ITC)

The results of the sensitivity analyses are presented in the tornado diagram in Figure 4-1. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized busbar cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that capacity factor and capital cost are by far the most significant factors affecting the economics of a wind energy facility.

Figure 4-1: Base Case Sensitivity Analysis Tornado Diagram



4.4 CAPACITY FACTOR SENSITIVITY ANALYSIS

BMcD further evaluated the sensitivity of the Project's levelized busbar cost to net annual capacity factor. Figure 4-2 below demonstrates the impact on levelized busbar cost as capacity factor is varied. As expected, the Project's busbar costs drop significantly as capacity factor increases.

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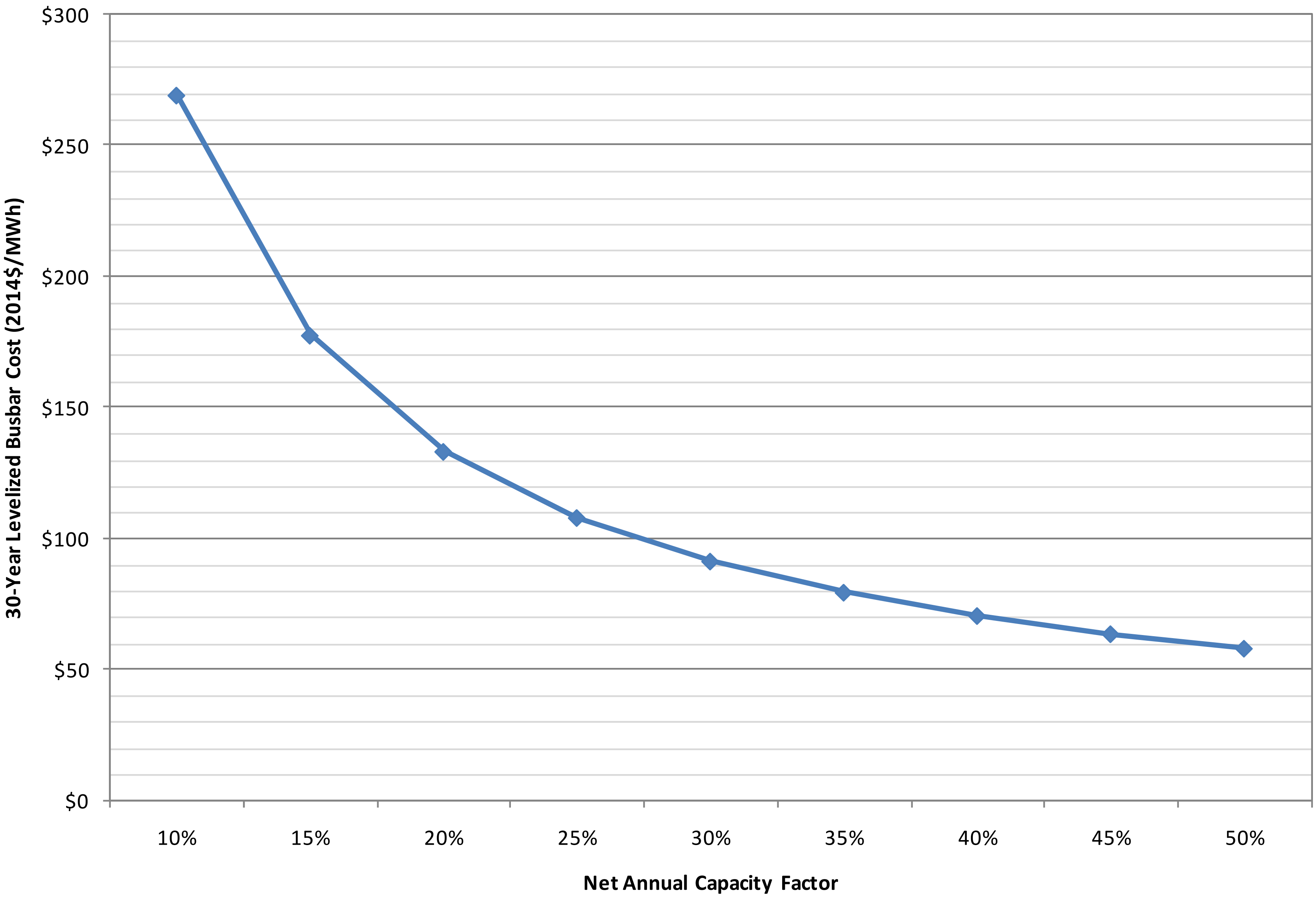
Figure 4-2: Levelized Busbar Cost Variation with Net Annual Capacity Factor



SECTION 5

ELECTRIC TRANSMISSION CAPITAL COST EVALUATION

5.0 ELECTRIC TRANSMISSION CAPITAL COST EVALUATION

BMcD completed an evaluation of electric transmission system capital cost investments required to move wind energy between the Project's potential source and sink locations. To perform this analysis, an annual capacity factor was assumed for a potential source and sink location, along with both the expected electrical losses likely to occur when moving wind energy between these Project locations and the expected annual, levelized carrying charge factor for the electric transmission infrastructure. Based on these inputs, as well as the base pro forma assumptions noted above, a breakeven capital investment cost was calculated. This cost, expressed in total capital cost per kilowatt of incremental transfer capability realized, represents the maximum allowable investment in electric transmission infrastructure that can be expended before the source location's busbar cost would exceed the busbar cost of a similar project at the sink location.

5.1 BASE CASE BREAKEVEN CAPITAL COSTS

As a base case scenario, the following assumptions were utilized in the calculation of the breakeven transmission investment:

- Source Location Capacity Factor 40%
- Sink Location Capacity Factor 20%
- Electrical Losses 5%
- Transmission Carrying Cost 15%

Based on these assumptions, a 20 percent capacity factor differential between the source and sink location yields a breakeven capital cost of approximately $1,320 per kW. Thus, a project sited in a wind-rich area could justifiably spend up to $1,320 per kilowatt of incremental power transfer capability on transmission infrastructure and remain economically competitive with a similar project sited in an area with an annual capacity factor that is 20 points lower than the source location. Note that breakeven transmission investment costs are expressed in 2014 dollars.

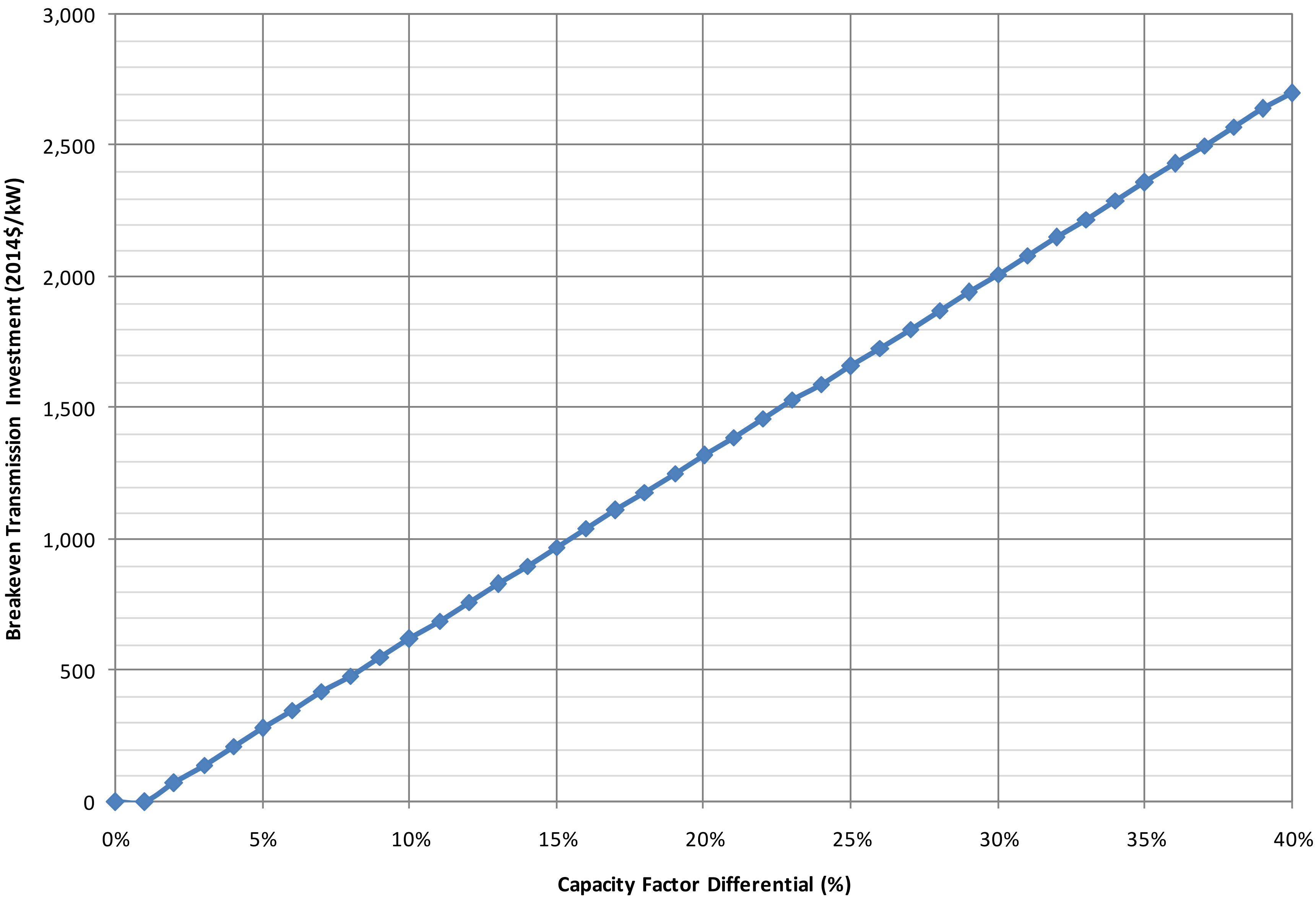
Although the breakeven capital cost of $1,320 per kW calculated on a unit basis, making it generally independent of Project size, the overall financial investment will vary significantly as the Project capacity increases. For example, a 100-MW wind farm could justifiably spend up to $132 million on electric transmission infrastructure under the base case scenario ($1,320/kW x 100 MW x 1,000 kW/MW = $132 million). If this wind farm were scaled up to 1,000 MW, the breakeven capital cost would remain constant on a unit ($/kW) basis, but the overall financial investment would increase ten-fold to $1.32 billion.

5.2 CAPACITY FACTOR DIFFERENTIAL SENSITIVITY ANALYSIS

As noted in Table 3-5, the highest average annual capacity factor of any potential Project location is 40.6 percent (South Dakota); the lowest average annual capacity factor of any potential Project location is 22.8 percent (Missouri). Thus, a capacity factor differential of 20 percent, as utilized in the base case breakeven capital cost evaluation, represents a best-case scenario in terms of the capacity factor differential between potential source and sink locations.

A sensitivity analysis was completed on the breakeven transmission investment to examine the impact of variations in capacity factor differential. As seen in Figure 5-1, the breakeven transmission investment drops as capacity factor differential decreases. Thus, the smaller the gap in capacity factor between the Project's source and sink locations, the smaller the justifiable investment in electric transmission infrastructure to move the wind energy between the two locations.

Figure 5-1: Breakeven Transmission Capital Cost by Capacity Factor Differential



5.3 PROJECT EXAMPLE

The following example is intended to illustrate a specific Project scenario. Under this example, a 1,000-MW wind farm is developed in North Dakota. Energy from the wind farm is transferred on a high-voltage transmission line to an off-take location in another state. All potential Project locations were evaluated as off-take points.

Based on information derived from the Regional Capacity Factor Characterization task, the average gross annual capacity factor in North Dakota is approximately 36.2 percent. The average gross annual capacity factors at the potential sink locations, along with the corresponding capacity factor differential from the North Dakota source location, are summarized in Table 5-1 below. From these differentials, a breakeven transmission investment was calculated for each off-take location to assess the maximum investment that could justifiably be made in electric transmission infrastructure.

Table 5-1: Breakeven Transmission (From North Dakota)

Off-Take Location	Average Annual Capacity Factor	CF Differential	Breakeven Cost ($/kW)	State-to-State Distance (mi.)
DE	25.5%	10.7%	$ 500	1,371
IA	33.6%	2.6%	$ 30	511
IL	27.6%	8.5%	$ 350	759
IN	23.3%	12.9%	$ 690	874
MD	23.7%	12.5%	$ 660	1,359
MI	24.6%	11.6%	$ 580	800
MN	35.0%	1.2%	$ -	335
MO	22.8%	13.4%	$ 740	748
ND	36.2%	0.0%	$ -	-
NE	33.2%	3.0%	$ 50	414
NJ	24.3%	11.9%	$ 600	1,366
NY	24.3%	11.9%	$ 600	1,197
OH	23.0%	13.2%	$ 720	1,010
PA	24.2%	12.0%	$ 610	1,205
SD	40.6%	-4.4%	$ -	225
VA	23.7%	12.5%	$ 660	1,226
WI	25.0%	11.2%	$ 540	532

Notes:

1. Assumes source project location of ND.
2. Assumes project with 1000 MW nameplate capacity.
3. Assumes electrical losses of 5 percent.
4. Assumes transmission carrying cost factor of 15 percent.
5. State-to-State Distances represent distance between the centroid of ND and the corresponding centroid of each state.

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SECTION 6

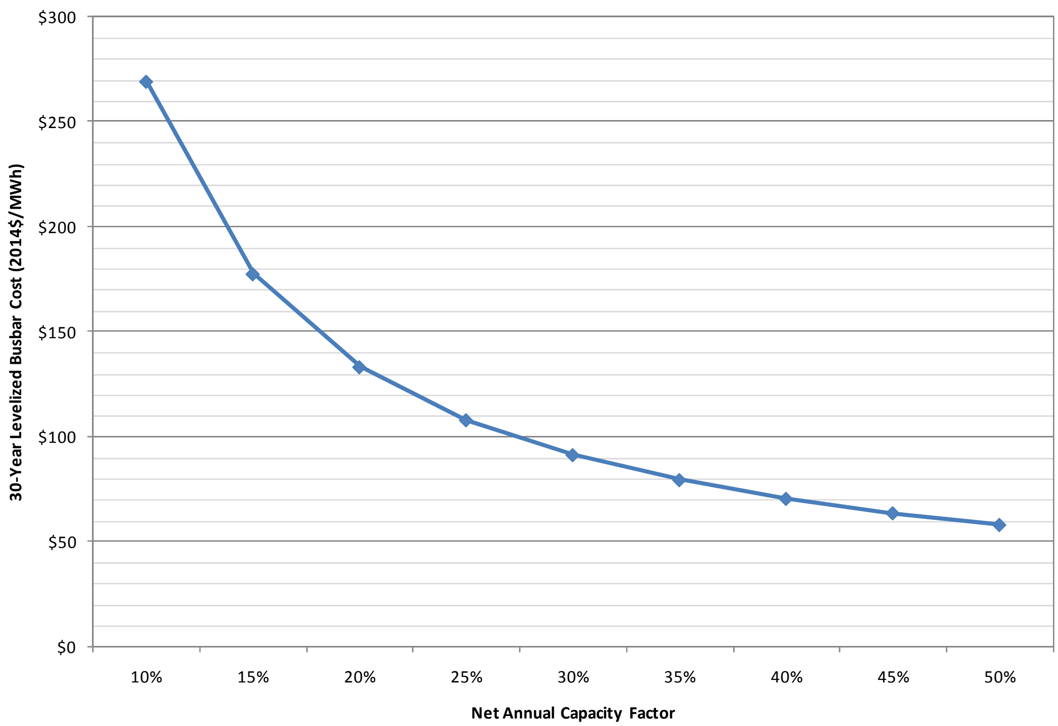
SUMMARY AND CONCLUSIONS

6.0 SUMMARY AND CONCLUSIONS

The purpose of this Study was to create an economic model to assess the viability of transporting wind energy from wind-rich areas in the northern United States to eastern load centers. This model was designed to evaluate the 30-year levelized busbar cost of energy from the Project based on several base-case assumptions and economic inputs. These assumptions may be modified at the user's discretion to evaluate any combination of Project options.

Utilizing the base assumptions in the pro forma economic model, the 30-year levelized busbar cost of the generic 100-MW Project was estimated to be $73.62 per MWh (2014$). In current (2010) dollars, this would be approximately $68.02 per MWh. Figure 6-1 below demonstrates how the levelized busbar cost of wind generation varies with capacity factor.

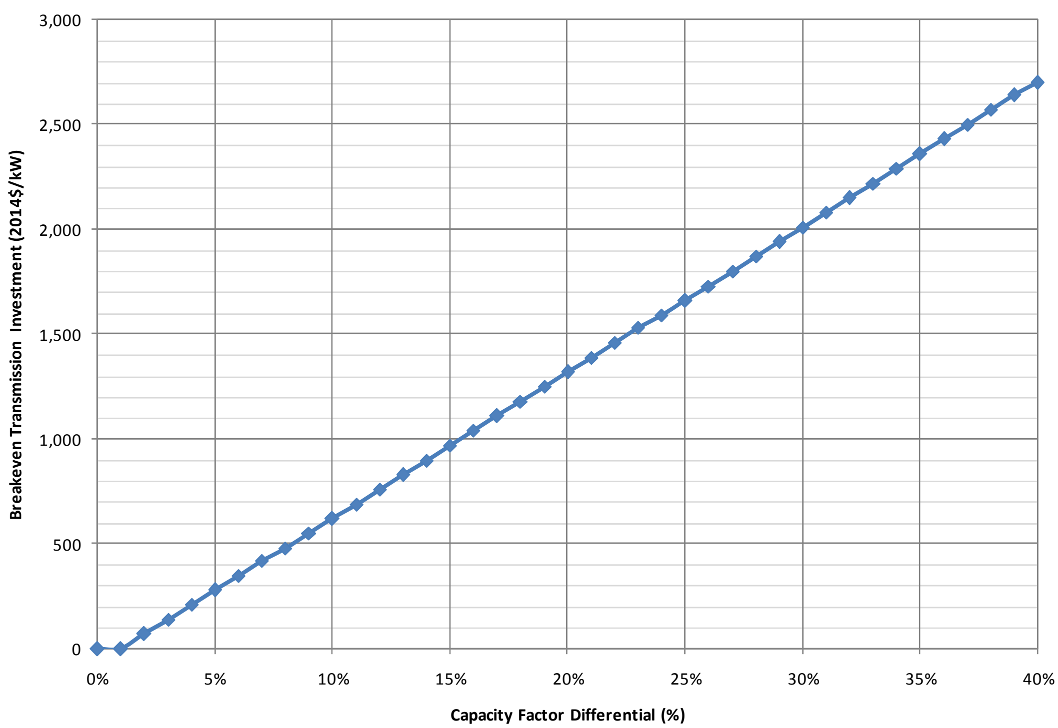
Figure 6-1: Levelized Busbar Cost Variation with Net Annual Capacity Factor



BMcD also characterized the expected capacity factor ranges that are likely to occur between various Project locations. This task, completed entirely with publically-available data, revealed the most attractive source location for the Project to be South Dakota, with an average gross annual capacity factor of approximately 40.6 percent. Conversely, the state with the lowest average gross annual capacity factor was Missouri (22.8 percent).

Finally, utilizing the pro forma economic model and capacity factor ranges noted above, BMcD determined the breakeven electric transmission system capital cost investments that could be economically justified by a differential in wind generation capacity factors between any two states considered in the Study. Based on results of Task 1 (Regional Capacity Factor Characterization), the largest differential in capacity factor between any source and sink location is not expected to exceed 20 percent. Assuming that scenario, the breakeven transmission investment was estimated at $1,320 per kilowatt. Thus, a project sited in a wind-rich area could justifiably spend up to $1,320 per kilowatt of incremental power transfer capability and remain economically competitive with a similar project sited in an area with an annual capacity factor that is 20 points lower than the source location. As demonstrated in Figure 6-2 below, the amount of transmission investment that an entity could economically justify to provide the required capability to transfer wind energy decreases as the differential in capacity factor narrows.

Figure 6-2: Breakeven Transmission Capital Cost by Capacity Factor Differential



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APPENDIX A

NREL WIND RESOURCE MAP

Figure A-1: NREL 50-Meter Wind Resource Map