BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE FILING BY SUPERIOR RENEWABLE ENERGY LLC ET AL. AGAINST MONTANA-DAKOTA UTILITIES CO. REGARDING THE JAVA WIND PROJECT	))))))	EL04-016

TESTIMONY OF EDWARD D. KEE

31 JANUARY 2005

TABLE OF CONTENTS

EXHIBITS:

Exhibit No. EDK-1:	Edward D. Kee CV
Exhibit No. EDK-2:	Documents reviewed
Exhibit No. EDK-3:	Avoidable capacity costs
Exhibit No. EDK-4:	Levelized avoidable capacity costs
Exhibit No. EDK-5:	Stipulated avoided energy costs
Exhibit No. EDK-6:	"The Costs of Wind's Variability: Is There a Threshold?" Electricity Journal, Jan/Feb 2005, Pages 69-77
Exhibit No. EDK-7:	Xcel Energy and the Minnesota Department of Commerce Wind Integration Study - Final Report dated September 28, 2004
Exhibit No. EDK-8:	Term sheet for Java Wind Project Power Purchase Agreement

I. INTRODUCTION

Q. Please state your name, title, and business address.

A. My name is Edward D. Kee. I am member of the management group of PA Consulting Group, Inc. ("PA"), a global management and technology consulting firm. My business address is PA Consulting Group, 1750 Pennsylvania Avenue, NW, Washington, DC 20006.

Q. Please summarize your professional qualifications and educational background.

A. I have been a senior consultant and member of the management group at PA since 2000. I joined PA when the firm of PHB Hagler Bailly, where I was a Senior Vice President, was acquired. Between 1997 and 2000, I established and led the Putnam, Hayes & Bartlett ("PHB") Australian practice, where I was involved in electricity industry restructuring and privatization through a range of client engagements. Prior to establishing PHB's Australian practice, I was a Director in PHB's Washington DC office. I received a BS in Systems Engineering from the United States Naval Academy and an MBA from Harvard University. My full CV is attached as Exhibit No. EDK-1.

Q. Please describe your background and experience in the electricity industry.

A. I am a specialist in the electricity industry, with experience in issues of electricity industry restructuring, electricity markets, independent power, and other areas. I have testified as an expert witness in civil litigation and regulatory proceedings on a range of electricity industry issues.

Q. Whom do you represent in this proceeding?

A. I am presenting testimony on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota").

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to address issues 6 and 7 in the Notice of Investigation under SDCL 49-34A-26 and Order for and Notice of Procedural Schedule and Hearing EL04-016, dated 26 October 2004 (the "EL04-016 Order") establishing this proceeding ("Proceeding") issued by the Public Utilities Commission of the State of South Dakota (the "SDPUC") and to provide a rebuttal of the testimony presented by witnesses on behalf of Superior Renewable Energy LLC ("Superior").

Issue 6 is:

> "Whether, and in what amounts, Montana-Dakota should be required, pursuant to 16 U.S.C. § 824a-3 and 18 C.F.R. §§ 292.303 and 292.304, to pay Superior over the life of the Java Wind Project for electricity made available to Montana-Dakota from the project? The determination of this Issue will require consideration of the avoided cost issues presented by 18 C.F.R. § 292.304 including, but not limited to, both avoided energy costs and avoided capacity costs."

Issue 7 is:

> "Whether additional relief should be granted to Superior as necessary for Superior to obtain a power purchase agreement with Montana-Dakota for electricity produced from the Java Wind Project on terms that are

consistent with the requirements of PURPA and the SDPUC PURPA Order and are as consistent as possible with the respective positions of the parties and with the interests of Montana-Dakota's rate payers and public?"

Q. What documents have you reviewed in developing this testimony?

A. Exhibit EDK-2 is a list of the documents provided to me by Montana-Dakota in connection with this Proceeding. I have reviewed a number of other publicly available documents, including PURPA and the Federal Rules implementing PURPA, Federal Energy Regulatory ("FERC") decisions, Qualifying Facility ("QF") filings, state utility commission decisions, MISO documents, MAPP documents and analyses of and reports on wind energy.

Q. What are your conclusions?

A. I discuss and support these conclusions in my testimony:

- The electricity industry has changed significantly since PURPA and Order F-3365 and these changes should be reflected in this Proceeding
- This Proceeding should not be used to promote wind energy or wind generation development in South Dakota
- Any avoided capacity payments to the proposed Java Wind Project must be no more than the *minimum* monthly MAPP accredited capacity during Montana-Dakota's peak period (ie, 7 MW)
- Any avoided energy costs should be linked to MISO spot market prices when the MISO Day 2 electricity market is operational
- There are important PPA terms that must be agreed between the parties

II. CONTEXT OF THIS PROCEEDING

Q. What does this section of your testimony cover?

A. In this section of my testimony, I provide a discussion of the Public Utilities Regulatory Policies Act of 1978 ("PURPA") and SDPUC Decision and Order F-3365 dated 14 December 1982 ("Order F-3365").

A. PURPA

Q. Was the implementation of PURPA consistent across states?

A. No. There were significant differences in the implementation of PURPA between states. Some states took the minimum action required under PURPA, such as establishing a standard offer process for small QFs. Other states, including California and New York, implemented PURPA through detailed state rules, standard contracts, long-term pricing and other procedures that went well beyond the requirements of PURPA.

Q. Are there lessons that the SDPUC should consider from other states?

A. Yes. The primary lessons are that it is important to get avoided costs correct and that obligations to purchase QF power can impose significant financial risks on purchasing utilities and their customers.

Q. Why is it important to get avoided costs right?

A. Avoided costs that are too high have the potential to create stranded costs, to impose financial stress on the purchasing utility, and to increase the rates paid by the customers of the purchasing utility.

Q. What potential risks are imposed by QF purchase obligations?

A. The implementation of PURPA in some states, such as New York and California, resulted in the setting of stipulated avoided costs in standard contracts where these stipulated avoided costs proved to be well above actual avoided costs, during the term of the standard contracts. Some of the standard QF contracts resulted in costs that were well above market prices for power and so provided above-market returns to the QF project owners. A flood of QF projects resulted from the strong financial incentive of above-market prices in standard offer QF contracts. While these standard offer contracts were eventually withdrawn or revised, a large number of QF projects obtained contracts. The obligation to purchase QF power in these states imposed significant financial stress on the purchasing utilities.

Q. Does PURPA prevent purchasing utilities from paying long-term prices above avoided cost?

A. There is no protection for purchasing utilities and their customers if long-term stipulated prices in a QF contract turn out to be higher than actual avoided costs at some point during the term of the contract. PURPA states, in 292.304 (b) (5), that long-term QF contracts with stipulated prices are binding even if the prices differ from actual avoided costs later during the contract term. Accordingly, states implementing PURPA should carefully consider the long-term implications of QF contracts with prices stipulated at the time of contract execution. Such contracts may place significant risk on purchasing utilities and the customers of the purchasing utilities.

Q. What is the current status of PURPA?

A. The PURPA mandatory purchase obligation is incompatible with the electricity industry in 2005. Congress has considered the repeal of the mandatory QF purchase provisions of PURPA for years and is likely to consider an energy bill in 2005 that includes repeal of mandatory QF purchase provisions.

Q. Why are the PURPA mandatory purchase obligations incompatible with the current electricity industry?

A. Competition in wholesale electricity generation has been created by the enactment of the Energy Policy Act of 1992, the issuance of FERC open-access rules in 1996 (Orders No. 888 and 889), and other industry changes since PURPA was enacted in 1978. Today, electricity generators and wholesale customers have access to each other under the same terms and conditions applicable to the utility owning the transmission wires. QFs have the right to request transmission service and to sell power to any wholesale customer, just like any other non-QF generator. QFs do not need the special privilege of being able to sell to a purchasing utility at the utility's "avoided cost" rate. The development of wholesale electricity markets, including the MISO market, will further facilitate electricity trading and reduce the role of traditional vertically integrated utilities as the dominant buyer in the wholesale power market.

PURPA requires electric utilities to purchase power from QFs at administratively - determined prices. These prices were supposed to ensure that consumers would pay no more for PURPA power than for other power, but this has not always been the outcome. Instead, long-term PURPA contracts have often included prices that were far above avoided costs and above competitive market prices of electricity and these out-of-market contracts enjoy the protection of PURPA.

Q. What was the intent of the PURPA provisions and how have industry changes affected this?

A. PURPA imposed obligations on utilities to purchase QF power as a response to the industry structure in place in the 1970s, when PURPA was enacted. In the pre-PURPA industry structure, each electric utility held monopsony power. That is, state laws and regulations implementing the monopoly utility franchise concept meant that the regulated utility was the only buyer of power in its own service territory – essentially resulting in the regulated utility acting as a "single buyer." This meant that a non-utility generator had only one party to which it could sell power – the regulated utility in whose service territory the non-utility generator was located. As open access to the transmission network, electricity markets, IPPS, market-based rates and related changes were implemented, the single buyer industry structure that drove PURPA was no longer relevant. As a result of electricity industry reform, all participants, including non-utility generators, have a ready market in which to buy and sell power.

Q. How will electricity markets change the avoided cost concept?

A. In PURPA and in Order F-3365, the avoided cost concept is focused on the purchasing utility's costs and how those costs might be changed as a result of purchasing QF power. This is a direct result of the "single buyer" concept discussed above and reflects the electricity industry structure and mode of operation at the time that PURPA was enacted.

Where electricity markets are in place and the utility purchaser of QF power is participating in that electricity market, the market price for power establishes a better measure of the value of incremental energy and may provide a better measure of avoided energy costs than an examination of the internal avoided costs of the purchasing utility.

Q. Have some states used electricity market prices as a measure of avoided energy costs?

A. Yes. I describe how this was done in two states, Texas and California.

The Public Utilities Commission of Texas ("PUCT") decided in 2001 that it was appropriate to use a market-based pricing method for calculating avoided cost as opposed to a pricing method that is formulaic in determining avoided cost. The PUCT found that the closest approximation of a market price for avoided cost is the market-clearing balancing energy price for the ERCOT congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties, and fees typically applied to power generators. The PUCT found that this price most closely reflected avoided costs for the marginal unit of energy. (PUCT Order Adopting Amendments to §25.242 As Approved at the June 6, 2002 Open Meeting, Project No. 24365, Rulemaking Concerning Arrangements Between Qualifying Facilities And Electric Utilities.)

The California Public Utilities Commission ("CPUC") in 2000 adopted the day-ahead zonal Power Exchange ("PX") market-clearing price as the short-run avoided cost ("SRAC") energy price. The CPUC concluded that the PX price represents an "all-in" price for must-take QFs, containing both energy and capacity value and eliminated as-available capacity payments to QFs holding as-available contracts. For other QFs, the CPUC found that the PX price contained some value for capacity and adopted the provisions of Public Utilities Code § 390 (d) that govern removal of the value of capacity from the PX price. The CPUC concluded that if the PX is the market where the utilities procure the majority of their energy requirements and it reasonably represents the costs of other utility purchases, then the PX represents the utilities' avoided cost and is functioning properly for the limited purpose of paying QFs. (Before the Public Utilities Commission of the State Of California, Order Instituting Rulemaking into Implementation of Pub. Util. Code § 390, Rulemaking 99-11-022). The demise of the California Power Exchange in 2001 meant that this approach was abandoned in California, but it remains a valid concept.

Q. Is Montana-Dakota a part of an electricity market?

A. Yes. There is now a functioning bilateral power market in the Mid-Continent Area Power Pool ("MAPP") region and Montana-Dakota is a part of the Midwest Independent System Operator ("MISO") market, with the MISO Day 1 market in operation. The MISO Day 2 market (ie, an electricity spot market with locational marginal pricing) is scheduled to be placed into operation in 2005.

Q. How might the MISO spot market prices be used in this Proceeding?

A. As I discuss later in the section on avoided energy costs, I propose that any PPA with the proposed Java Wind Project provide for a transition from administratively determined stipulated avoided energy costs to MISO spot market prices at the time that the MISO Day 2 electricity market is in operation. I note that the current

MISO schedule anticipates that the Day 2 electricity market will be operational in 2005, prior to the projected operation date of the proposed Java Wind Project.

Q. Does the current status of PURPA lead to any other implications for this Proceeding?

A. Yes. The current status of PURPA and the changes in the electricity industry since PURPA are critical factors that lead me to conclude that any QF purchase obligation in a Power Purchase Agreement ("PPA") should be limited in term to no more than 10 years.

Q. Why should the term of a QF PPA be limited to no more than 10 years?

A. Significant changes have occurred in the electricity industry since PURPA and Order F-3365. In addition to open access and electricity markets, thermal technologies (ie, combined cycle gas turbine plants) have improved costs and efficiencies; fuel prices have shown significant fluctuations, both lower and higher; and regional imbalances in supply and demand have led to increased volatility and uncertainty in electricity spot market prices. The mandatory utility purchase obligations under PURPA may be repealed. Long-term QF PPAs would be inconsistent with the electricity industry and would provide subsidies to the QF – allowing the QF to obtain contract terms and financial security that are not otherwise available in the electricity market. There is no justification for insisting that Montana-Dakota and its customers assume a long-term QF PPA in this increasingly open and competitive industry.

Other state utility regulators have decided that the uncertainty in the electricity industry regarding structure, markets, PURPA repeal, and related factors make it risky for a regulated utility to sign long-term QF PPAs and have limited the term of such PPAs to less than 10 years.

B. PURPA IMPLEMENTATION IN SOUTH DAKOTA

Q. Should this Proceeding be used to promote wind energy?

A. No. Superior raises issues in their letters and testimony that are focused on wind energy, rather than on PURPA implementation or on the issues set by the SDPUC in this Proceeding. This suggests that Superior is attempting to use this Proceeding to promote wind energy in South Dakota as a means of gaining more favorable prices in their own QF contract. While PURPA was designed to encourage renewable resources such as wind, PURPA should not be used inappropriately to provide subsidies to wind energy. This Proceeding should be focused solely on the implementation of PURPA and on the Issues set for the Proceeding by the SDPUC.

Q. Does this Proceeding have any impact on other states in the region?

A. Potentially. Montana-Dakota has an integrated system that covers areas in Montana, North Dakota, and South Dakota, while the proposed Java Wind Project is located in South Dakota. Superior's complaint suggests that the entire Montana-Dakota system should be considered in the current Proceeding in South Dakota, even though less than 10% of the Montana-Dakota load is located in South Dakota. As discussed in the Testimony of Mr. Ball, any QF purchase obligations imposed on Montana-Dakota as a result of this Proceeding should properly reflect the issues arising from Montana-Dakota's operation in three states under the jurisdiction of three separate utility regulatory commissions.

Q. What are the longer-term implications of this Proceeding?

A. I see at least two implications.

First, this Proceeding may result in a long-term PPA in which Montana-Dakota will be required to purchase power from the Java Wind Project. To the extent that the prices in this PPA are sufficiently high to provide an attractive return, the Java Wind Project may be built and may perform under the terms of the PPA. This PPA will become a long-term legally enforceable obligation on Montana-Dakota with special protection under PURPA. This PPA has the potential to put financial stress on Montana-Dakota and the potential to increase the costs borne by Montana-Dakota's customers if avoided costs are not properly determined. This first set of implications is properly considered in this Proceeding.

Second, should Superior find the terms of the PPA arising from this Proceeding attractive, it is likely that PPAs with similar terms and prices will be sought by other wind developers. While this Proceeding is not a generic proceeding on PURPA implementation for large QFs in South Dakota or on wind energy development in South Dakota, the outcomes of this Proceeding will likely establish precedents on both of these topics. This second set of implications are not formally included in this Proceeding, but should be considered by the SDPUC.

C. ORDER F-3365 GUIDANCE

Q. What is Order F-3365?

A. Order F-3365 is the primary document that establishes the South Dakota implementation of PURPA. While Order F-3365 provides some guidance on certain PPA parameters (ie, prices), there is little guidance on other financially important PPA terms.

Q. What does Order F-3365 say about the role of the SDPUC in implementing PURPA for large QF projects?

A. Order F-3365 distinguished between small QF projects (ie, less than 100 KW) and large QF projects and established a role for the SDPUC in implementing PURPA for large QF projects:

"The Commission finds that . . . it will not implement standard rates for purchases from QF's with a design capacity of greater than 100 KW." (Section VI A; Page 10, third paragraph) "The Commission finds that rates for purchases from QF's with a design capacity of more than 100 KW should be set by contract negotiated between the QF and the electric utility." "The Commission agrees . . . that the Commission should play a minimal role in the negotiation of such contracts, a role limited to resolving any contract disputes which arise between the parties." (Section VI A; Page 11, first paragraph)

Order F-3365 anticipates the negotiation of a PPA between a large QF and the purchasing utility, with the SDPUC acting to resolve disputes. In this process, negotiations between Superior and Montana-Dakota would have commenced on or after the date that the proposed Java Wind Project became a QF (ie, the QF self-certification dated 15 April 2004). The discussions and negotiations between Montana-Dakota and Superior prior to this date are outside the realm of Order F-3365. The role of the SDPUC in resolving "contract disputes which arise between the parties" anticipates that a PPA (ie, a contract) has been discussed by the parties. As far as I know, Superior has not presented a draft PPA to Montana-Dakota. I provide a set of recommended PPA terms between Montana-Dakota and the proposed Java Wind Project as part of my testimony.

Q. Did the SDPUC provide any guidance for PPAs related to large QFs?

A. Yes. The SDPUC, in conjunction with its role in resolving any disputes between a QF and the purchasing utility, also provided some parameters for the PPAs to be negotiated:

> "The Commission finds . . . that . . . it should set certain parameters for the negotiation of such contracts." "The Commission finds that Staff's recommendations on contractual purchase rates are reasonable and should be adopted as minimum requirements for purchase rate contracts." (Section VI A; Page 11, second paragraph)

Section VI-A of Order F-3365 provides more details on the SDPUC's guidance with respect to the parameters of negotiated PPAs. I note that the recommendations and the findings on contract parameters are primarily related to purchase rates, rather than other PPA terms and conditions.

Q. Does Order F-3365 distinguish between short-term and long-term contracts?

A. Yes. The SDPUC decided that there is a basis to distinguish between short-term and long-term PPAs, with the distinguishing factor being the length of PPA term.

> "The Commission finds that it is reasonable to distinguish between short-term and long-term contract purchase rates . . ." "The Commission finds that Mr. Bernal's testimony offers a rational basis for distinguishing between rates for purchases fixed by contract with a duration of less than 10 years ('short-term contract') and rates for purchases set by contract with a duration of 10 years or more ('long-term contract'). (Section VI A; Page 11, third paragraph)

As Order F-3365 does not provide guidance on this, I conclude that the length of the PPA term is a factor that is to be decided in negotiations between the QF and the purchasing utility. The term of any PPA between Montana-Dakota and the Java Wind Project is an issue that must be resolved and that I discuss in more detail below. As discussed below, Order F-3365 provides additional guidance on avoided capacity payments, with a long-term PPA likely receiving higher capacity payments as compared to a short-term PPA. Given this difference, I would expect that any QF seeking to negotiate a PPA would seek a long-term PPA in order to obtain these higher capacity payments.

Q. What is the basis for avoided capacity costs in Order F-3365?

A. The distinction between short-term and long-term PPAs (ie, whether the PPA term is 10 years or more) is also the basis for deciding capacity avoided cost payments.

"The Commission finds that Staff Witness Bernal correctly identified the basis for long-run versus short-run avoided capacity costs. The Commission finds that long-term contracts and short-term contracts should reflect such avoided capacity costs through capacity credits." (Section VI A; Page 11, fourth paragraph, continuing onto page 12)

Avoided capacity costs should be included in both short-term and long-term PPAs through "capacity credits." Order F-3365 is silent on the definition of capacity credits. This term seems to have a meaning that is either related to the price in a PPA or related to the actual payments resulting from a PPA. The potential difference in this meaning is discussed later.

Q. Does Order F-3365 provide guidance on whether avoided capacity payments must be made if actual capacity is not avoided?

A. Yes. Order F-3365 provides a clear and emphatic guideline on avoided capacity.

"The Commission finds that the capacity credits to be included in any purchase rates, whether contractual or otherwise, should be based on capacity <u>actually</u> avoided, and if the purchase does not enable a utility to avoid capacity costs, capacity credits should not be allowed." (Section VI E; Page 17, third paragraph) "The Commission does not read the FERC's rules to permit a utility to pay capacity costs where none are avoided. To do so would have the effect of requiring the utility to pay twice for the same capacity and would thus impose added and unnecessary costs on the utility's other customers, contrary to clear congressional and FERC intent." (Section VI E; Page 18, first full paragraph)

Order F-3365 establishes a rule that only when capacity is actually avoided will any capacity credits be included in rates. In this Proceeding, it is important to ensure that avoided capacity costs are consistent with this finding.

Q. What does Order F-3365 say about the basis for avoided capacity credits in short-term contracts?

A. The basis for capacity credits in short-term PPAs is the cost of installed turbine peaking generation.

"The Commission finds that capacity credits included in short-term contracts should be based on the cost of installed turbine peaking generation, as short-term contracts will primarily tend to reduce the use of peaking generation, and thus reduce the utility's use of more expensive and non-renewable fuels such as oil and gas." (Section VI A; Page 12, first paragraph)

Capacity credits here refer to PPA prices. The rationale for this finding is that no base load generation would likely be avoided as a result of a QF PPA of less than 10 years duration. This rationale also suggests that a longer-term PPA may not allow the purchasing utility to avoid any base load generation during the first 10 years of the PPA.

Q. What does Order F-3365 say about the basis for avoided capacity credits in long-term contracts?

A. The basis for capacity credits in long-term PPAs is the cost of base load generation.

"The Commission finds that capacity credits included in long-term contracts should be based on the cost of base load generation. (Section VI A; Page 12, first paragraph)

Capacity credits here refer to PPA prices. The rationale for this finding is that a PPA term that is greater than 10 years would potentially allow the purchasing utility to avoid the construction of a base load generator.

Q. What does Order F-3365 say about constant or levelized avoided capacity credits?

A. Capacity credits in long-term PPAs should be constant over the duration of the PPA.

> "The Commission also finds that the capacity credits included in long-term contracts should be made constant over the duration of the contract." (Section VI A; Page 12, second paragraph)

This finding anticipates the situation where a purchasing utility has different avoided units over the term of a QF PPA. If there are different avoided units with different avoided capacity costs over the term of the QF PPA, these different prices must be converted to a PPA avoided capacity price that is constant over the duration of the contract. This is accomplished by calculating the levelized (ie, constant) stream of capacity prices that has the same net present value as the actual avoided cost prices over the length of the PPA term.

Q. What does Order F-3365 say about the basis for avoided energy costs?

A. This finding provides guidance on the calculation of avoided energy costs.

> "The Commission finds that both short-term and long-term contracts should include an energy credit based on the *average* (emphasis added) of the expected hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility. The Commission finds . . . that such a basis of calculation recognizes that the avoided energy cost to the utility's system changes constantly. Hourly incremental costs vary greatly depending on which unit of generation is being added in the next increment. The Commission finds that Staff's recommendation will accurately track the actual avoided energy cost to the utility." (Section VI A; Page 12, third paragraph)

The energy credit (or energy payment) must be based on an analysis of the incremental avoided energy costs of the utility. This analysis can be conducted by performing two production cost simulation runs, one without the QF (QF-Out) and one with the QF (QF-In). In QF-In run, any avoided units will also be reflected in the analysis, so that the avoided energy price is consistent with the assumptions about avoided units. That is, if the QF resulted in the purchasing utility avoiding a portion of a base load plant, the QF-In model run would not include the avoided portion of the base load plant.

Q. Is there any other guidance in Order F-3365 that may apply to large QF projects?

A. Yes. Order F-3365 states that the capacity credits included in long-term PPAs should reflect the average KW supplied by the QF for each month during the utility's on-peak period.

"The Commission further finds that capacity credits included in long-term contracts should reflect the average KW supplied by the QF for each month during the utility's on-peak period. (Section VI A; Page 12, first paragraph)

Superior has improperly interpreted this finding to support their conclusion that the capacity avoided as a result of the proposed Java Wind Project is the average of the monthly MAPP accredited capacity for the proposed Java Wind Project (as estimated by Superior) during Montana-Dakota's peak period. The Superior interpretation of this finding is in conflict with the other finding in Order F-3365 that utilities need not pay QFs avoided capacity payments for capacity that is not actually avoided.

My conclusion is that Montana-Dakota can avoid only the *minimum* monthly MAPP accredited capacity for the proposed Java Wind Project.

Q. Why do you conclude that the capacity avoided as a result of the proposed Java Wind Project capacity is the minimum summer monthly MAPP accredited capacity?

A. Montana-Dakota must have sufficient capacity to meet the summer peak demand during each summer peak month. The units that are avoidable as a result of the proposed Java Wind Project provide capacity that is the same in each summer peak month. The amount of the avoidable unit that can be avoided is set by the monthly MAPP accredited capacity for the proposed Java Wind Project, with the amount avoided equal to the minimum monthly MAPP accredited capacity in Montana-Dakota's summer peak months.

Superior wrongly asserts that the avoided capacity is the average of the monthly MAPP accredited capacity during Montana-Dakota's summer peak months. The Superior approach would result in contradicting other parts of Order F-3365 and create a financial burden on Montana-Dakota's customers as a result of paying the proposed Java Wind Project for more avoided capacity than this project actually allows Montana-Dakota to avoid.

III. ISSUE 6 – MONTANA-DAKOTA AVOIDED COSTS

Q. What does this section of your testimony cover?

A. In this section of my testimony, I provide a discussion of the Avoided Costs of Montana-Dakota as these avoided costs relate to the proposed Java Wind project.

Q. Is this issue set for consideration in this hearing?

A. Yes. Issue 6 of the SDPUC Order establishing this Proceeding does this.

Q. How have you analyzed Montana-Dakota avoided costs related to the proposed Java Wind project?

A. I have done separate analyses of avoided capacity costs and avoided energy costs.

A. AVOIDED CAPACITY COSTS

Q. What is your approach to estimating Montana-Dakota's avoided capacity costs in relation to a PPA with the proposed Java Wind Project?

A. My approach to estimating the avoided capacity cost payments related to a PPA with the proposed Java Wind Project has five components:

1. Avoidable units
2. Avoidable unit costs
3. Levelized avoidable capacity costs
4. Actual avoided capacity
5. Avoided capacity payments

1. Avoidable units

Q. What generating units or purchases might Montana-Dakota avoid as a result of purchasing capacity from the proposed Java Wind Project?

A. The units or purchases that Montana-Dakota might avoid as a result of purchases from the proposed Java Wind Project differ by year. Based on Ms. Stomberg's testimony, I have identified three future periods:

- Period 1 – this is the period from now until 15 June 2007.
- Period 2 – this is the period from the end of Period 1 until a new base load unit is operational.

- Period 3 – this is the period from the operation of a new baseload unit on 15 June 2011 until the end of the QF contract.

Q. Can you provide more information on the avoidable units in each of these 3 Periods?

A. Yes. As explained in more detail in Ms. Stomberg's testimony, Montana-Dakota is in the process of determining a resource plan for these periods and will make commitments to actual units at some date after my testimony is completed. For the purpose of this Proceeding, the avoidable unit in each period is the most economic unit identified in each period.

In Period 1, Montana-Dakota has sufficient capacity to meet the MAPP contingency reserve requirements and does not need any additional capacity. In Period 1, Montana-Dakota has no need for capacity, so there is no avoidable unit.

During Period 2, Montana-Dakota will make the most economic purchase of short-term peak period capacity in order to meet MAPP contingency reserve requirements. These short-term capacity options could consist of a short-term capacity purchase as a result of the current RFP or a seasonal lease of portable combustion turbine units. If Montana-Dakota locates a feasible short-term capacity purchase that is lower cost than the leased peaking unit option, that purchase would be accepted. At the time of my testimony, Montana-Dakota has not committed to any short-term capacity purchase options, so that the leased peaking units are used in my analysis as the avoidable unit in Period 2.

In Period 3, Montana-Dakota expects to acquire new base load coal capacity. The avoidable unit in Period 3 is this new base load unit. At the time of my testimony, Montana-Dakota has not committed to any new base load coal option. Currently, there are three options under consideration, Lignite Vision 21, Resource Coalition, and Big Stone II. At this time the most economic of these options is a share of a new large baseload coal plant in the region, rather than the construction of a new unit that is scaled-down to Montana-Dakota's requirements. Therefore, the avoidable unit in Period 3 used in my analysis is a share of a large new base load coal plant. I have used costs that are representative of the costs of this avoidable base load unit. These costs are comparable to the costs for the Big Stone II plant.

Q. Why have you selected a different baseload resource than the one identified by Montana-Dakota in its initial data responses?

A. The avoided unit that I have used in my analysis in Period 3 is more representative of the actual avoided unit than the Lignite Vision 21 plant. As Ms. Stomberg explains, the Lignite Vision 21 plant was identified by Montana-Dakota in its initial data responses, but Montana-Dakota has also been looking for other options. Another option is now considered more economic (ie, compared to the scaled-down version of the Lignite Vision 21 option) because of economies of scale.

2. <u>Avoidable unit costs</u>

Q. What are Montana-Dakota's avoidable capacity costs for Period 1?

A. In Period 1, Montana-Dakota's avoidable capacity costs are $0 per KW per month.

Q. What are Montana-Dakota's avoidable capacity costs for Period 2?

A. In Period 2, the avoidable unit is a leased portable turbine generation unit. Montana-Dakota has informed me that they have a quoted lease rate of $500,000 per unit per month for a 25 MW truck mounted turbine generator set. I have also included 10% of the lease rate as an estimate of the costs to set up these portable turbine generator sets and connect them to the Montana-Dakota system. Montana-Dakota would lease these units from June 15 to September 15, the 3-month summer peak period for Montana-Dakota. I assume that the first leases will take place starting on 15 June 2007. I estimate that Montana-Dakota's avoidable capacity cost during Period 2 is $66 per KW per year (ie, $22 per KW per month during the Montana-Dakota summer peak period from June 15 to September 15 and $0 per KW per month for the remainder of the year), escalated from 2005.

Q. What are Montana-Dakota's avoidable capacity costs for Period 3?

A. In Period 3, the avoidable unit is Montana-Dakota's part ownership of a large coal-fired base load unit. I have used cost estimates that are representative of such units in the Montana-Dakota region. I estimate that Montana-Dakota's avoidable capacity costs during Period 3 are $264 per KW per year.

Q. Have you provided the calculations you performed to obtain your estimates of Montana-Dakota's avoidable capacity costs?

A. Yes. Exhibit EDK-3 provides my estimates of the Montana-Dakota avoidable capacity costs and the assumptions and calculations I made to reach these estimates.

3. Levelized avoidable capacity costs

Q. Why are you developing a levelized avoidable capacity cost?

A. Order F-3365 requires that QF contract capacity credits (ie, prices for avoided capacity) are constant over the term of the QF contract. Because Montana-Dakota's avoidable capacity costs are different in each of the three periods described above, a calculation of the levelized avoidable capacity cost is necessary.

Q. How have you calculated levelized avoidable capacity costs for Montana-Dakota?

A. I assign an amount for Montana-Dakota's avoidable capacity cost to each year, depending on whether that year is in Period 1, Period 2, or Period 3. I then calculate the net present value of this multi-year set of avoidable capacity costs using the Montana-Dakota cost of capital. Using the same cost of capital, I then calculate an avoidable capacity cost that is constant (ie, levelized) and has the same net present value as the year-by-year Montana-Dakota avoidable capacity costs. The levelized avoidable capacity cost is different for different QF contract terms, so I perform this calculation for QF contract terms of 20, 15, 10, and 5 years.

Q. Have you provided calculations that you performed to obtain your estimates of the levelized avoidable capacity costs for Montana-Dakota?

A. Yes. Exhibit EDK-4 provides my estimates of the levelized avoidable capacity costs for Montana-Dakota and the assumptions and calculations I made to reach these estimates.

Q. Does this levelization of avoidable capacity payments present risks to Montana-Dakota and its customers?

A. Yes. Montana-Dakota's avoidable capacity costs are highest in Period 3, yet the calculation of levelized avoidable capacity costs mean that significant avoidable capacity payments may be made prior to Period 3. The levelizing of avoidable capacity payments results in "front-loaded" capacity payments. The magnitude of this front-loading is seen in Exhibit EDK-4, where 5-year levelized avoidable capacity costs are significantly lower than 20-year levelized avoidable capacity costs. A QF signing a 20-year PPA with Montana-Dakota would receive the higher levelized avoided capacity costs associated with the 20-year term. If that QF then ceased operation prior to the end of the 20-year PPA, Montana-Dakota and its customers would have overpaid for the capacity actually avoided.

Q. Why might a QF cease operation prior to the end of a long-term contract?

A. This might happen in order to maximize return to investors. The profitability of a QF project is a result of the annual cash flow to its equity investors. This cash flow is usually high in the initial period, but much lower, perhaps negative, in the later years of project operation. Some QF projects receive benefits in the form of accelerated depreciation and tax credits that are focused on creating tax benefits in the initial period of project operation; these benefits are not present in the later years of operation. The proposed Java Wind Project will have significant front loading of benefits as a result of 5-year tax depreciation and a ten year inflation-indexed production tax credit. Also, the operating and maintenance ("O&M") costs of a QF project may be low in the early years when the equipment is new and under manufacturer's warranties, but these costs may be higher in later years of project operation.

A QF with such "front-loaded" profits provides significant cash flow to investors in the early years, followed by much lower cash flow and perhaps even requirements for investors to make cash infusions to support project operation in later years. Such a QF project may find that investor return is increased if the QF ceases to operate prior to the end of the long-term contract to avoid these cash infusions. While the purchasing utility is required to continue purchasing from a QF even when such purchases are above-market, the QF has the normal commercial option of stopping operations and shutting down if the project is experiencing losses (ie, as might happen in the later years of the QF PPA).

The front-loading of avoidable capacity payments may exacerbate this front-loading of QF project profits and increase the financial incentive for the QF project to cease operations prior to the end of the contract term.

Q. Why would the QF seek a long-term PPA if it were more profitable for that QF to cease operations sooner?

A. A long-term PPA will result in higher levelized avoidable capacity payments than a short-term PPA because Montana-Dakota's actual avoided capacity costs are higher in Period 3. Accordingly, a 20-year PPA term would require that the levelized capacity costs be calculated over a period of 20 years, resulting in a higher levelized capacity cost than a 5-year PPA because the levelized capacity costs would be calculated over only the 5 years when Montana-Dakota has low (or no) avoided capacity costs. Thus, it would be more profitable for the QF to enter into a 20-year PPA, with the higher avoided capacity payments, and then shut down earlier (eg, after 10 years) than to have a 10-year PPA with lower avoided capacity costs.

Q. Could the proposed Java Wind Project PPA be structured to minimize the risk of front loaded payments?

A. Yes. There are two ways to minimize this risk.

The first way is to limit the term of the PPA. In addition to limiting the potential for risk associated with front-loaded avoidable capacity payments, a shorter-term PPA (ie, ten years) is consistent with the risk faced by Montana-Dakota, in terms of energy market evolution and PURPA repeal, as compared with a longer-term PPA. Also, I anticipate that the regional wholesale market and accompanying electricity industry reforms will be more established within ten years, providing Superior with a more mature market in which to sell its power.

The second way is to provide for early termination security in the PPA, with Montana-Dakota receiving a payment if the proposed Java Wind Project ceases operation prior to the agreed contract term. It is important that any such security is large enough to ensure that Montana-Dakota is no worse off if the QF ceases operation early and that the security is available even in the event that the proposed Java Wind Project was in bankruptcy.

4. <u>Actual avoided capacity</u>

Q. What are Montana-Dakota's capacity needs?

A. The capacity needs of Montana-Dakota are determined by the MAPP contingency reserve requirements and the expected Montana-Dakota peak demand in the summer. Montana-Dakota has a requirement to meet demand in all hours. To meet this requirement, Montana-Dakota has a portfolio of generating plants, power contracts, and other arrangements (ie, interruptible demand). In addition, Montana-Dakota must maintain a level of capacity that is greater than the expected peak demand, in order to meet contingencies (eg, a power plant outage), and to maintain system stability. MAPP defines contingency reserves as all generation reserves aside from regulating reserves. Montana-Dakota must meet MAPP contingency reserve requirements or face deficiency charges.

Q. What is the MAPP Accreditation Process that Superior mentions?

A. The MAPP Generation Reserve Sharing Pool Handbook provides the process through which a member meets its MAPP requirements for contingency reserve. A procedure is included in this handbook, in Section 4.2.2.7.2.7, by which wind or other intermittent and non-dispatchable generating capacity establishes a Monthly Net Capability amount.

Q. What is the significance of the "accredited generation" that results from this procedure?

A. First Section 4.2.2.6 requires that a MAPP Participant "must represent purchases from a non-Pool Participant's Variable Capacity Generation (such as wind, solar, and run-of-river hydro) as generating capacity listed in the Pool Participant's capability." In the context of this requirement, Montana-Dakota is a Pool Participant and the proposed Java Wind Project will not, so far as I am aware, be a Pool Participant. Accordingly, should Montana-Dakota purchase the output of the proposed Java Wind Project, this unit will be included in Montana-Dakota's generating capacity, with the amount of contribution toward Montana-Dakota's contingency reserve requirement determined by the MAPP accreditation procedure.

Q. What would the effect on Montana-Dakota and its customers be as a result of purchasing capacity from the proposed Java Wind Project?

A. By purchasing power from the proposed Java Wind Project, Montana-Dakota would be adding an amount of capacity, as determined by MAPP, that can help Montana-Dakota meet its MAPP contingency reserve requirements.

However, Montana-Dakota would not be adding capacity that provides the same attributes as the avoidable capacity of leased peaking units in Period 2 or the avoidable capacity of a base load coal unit in Period 3. Accordingly, Montana-Dakota is, under PURPA (18 CFR 292.304 (e)), justified in imposing a Wind Integration Adjustment that will reduce any payments to the proposed Java Wind Project to reflect the costs imposed on Montana-Dakota's system by the purchase of wind energy as compared to the purchase of conventional dispatchable generating capacity.

Q. How much capacity might the proposed Java Wind Project provide during Montana-Dakota's summer peak?

A. It is the lowest MAPP accredited monthly capacity of the proposed Java Wind Project during this summer period that determines the amount of capacity that might be avoided. This capacity is 7 MW, based on the information provided in Table 1 in Mr. Ferguson's testimony. As discussed in more detail later, the amounts in Mr. Ferguson's Table 1 are estimates and not the result of actual operation of the proposed Java Wind Project. Mr. Ferguson estimates that the proposed Java Wind Project provides capacity of:

- 9.5 MW in June
- 7.0 MW in July
- 11.3 MW in August, and
- 14.7 MW in September

Using Mr. Ferguson's estimates, Montana-Dakota might be able to avoid the minimum monthly amount of capacity of 7 MW in July.

Q. Why is the avoided capacity from the proposed Java Wind Project limited to the minimum monthly MAPP accredited capacity in the summer months?

A. The Montana-Dakota avoided units in Period 2 and Period 3 have an installed capacity that is constant across the summer peak months. These avoidable units cannot be adjusted to provide a different amount of capacity in each summer month to match the varying MAPP accredited amounts estimated for the proposed Java Wind Project. The amount of avoidable generation can be reduced by only the minimum monthly MAPP accredited capacity in the summer months.

Q. Are Superior's estimates of the monthly MAPP accredited capacity accurate?

A. Perhaps not. While I have only examined the information provided by Superior and have not examined the underlying calculations, there are a number of reasons why the Superior estimates of monthly MAPP accredited capacity may be wrong:

- Tower height correction - Superior has collected wind speed data from test towers that are shorter than the planned wind turbines and made adjustments to this wind speed data to reflect wind speeds at the expected height of the proposed wind turbines. The tower height correction factors may not accurately reflect wind speed for the actual wind turbines.

- Data points - The wind speed data provided by Superior contains a single data point for each hour and it is unclear whether this is the peak wind speed in that hour, the average of the wind speed over the hour, or some other amount. The approach used to convert actual wind speed data into hourly points may introduce significant error into the estimates.

- Superior converted this adjusted wind speed data to estimated wind turbine output using theoretical output conversion curves. These wind turbine conversion curves may not accurately reflect actual turbine output.

- Superior provided no information on the forced outage or availability assumptions used in developing output estimates. If perfect availability was assumed, these estimates will be too high

- Finally, Superior used this estimated power output to calculate its own estimates of MAPP accredited capacity.

Neither Superior nor Montana-Dakota will know the actual MAPP accredited capacity from the proposed Java Wind Project until after that project is completed and operational.

Q. Could the proposed Java Wind Project actually produce a different amount of capacity during the summer peak than is implied in Mr. Ferguson's MAPP accredited capacity estimates?

A. Yes. Actual operation of the proposed Java Wind Project will almost certainly result in output that is different from Superior's current estimates of output from the proposed Java Wind Project. For the reasons outlined above, actual output of the proposed Java Wind Project could be higher or lower than Superior's estimates.

Q. What is the implication of such uncertainty in the actual output of the proposed Java Wind Project?

A. Superior is seeking a long-term contract with Montana-Dakota that includes avoided capacity payments, even though there is significant uncertainty about the actual capacity provided by the proposed Java Wind Project. To account for the uncertainty about the capacity provided by the proposed Java Wind Project QF purchase, the PPA with the proposed Java Wind Project should initially reflect Superior's current estimate of avoided capacity (ie, 7 MW) and provide for long-term payments based on this amount. When the proposed Java Wind Project is completed, this amount of avoided capacity should be updated after every year of operation to reflect the new actual MAPP accredited capacity provided by the proposed Java Wind Project. The PPA should also provide for a refund of initial avoided capacity payments if the actual minimum monthly MAPP accredited capacity in the summer peak is less than 7 MW.

Q. Will Montana-Dakota really avoid any capacity as a result of purchasing capacity from the proposed Java Wind Project wind project?

A. Possibly not. 7 MW is a small part of the capacity likely to be acquired by Montana-Dakota in either Period 2 or Period 3. Montana-Dakota might not be able to change its capacity procurement plans as a result of this small amount of capacity. The intermittent and non-dispatchable nature of the capacity from the proposed Java Wind Project makes it even more unlikely that Montana-Dakota would alter its plans to procure firm and dispatchable capacity.

For the purposes of implementing PURPA, Montana-Dakota could potentially avoid 7 MW in Period 2 and Period 3, even though the actual result may be that Montana-Dakota cannot change its plans for capacity additions for either period.

Q. Does the proposed Java Wind Project need to obtain firm transmission capacity?

A. Yes. It is my understanding that the proposed Java Wind Project would need to obtain firm transmission capacity in order to receive any amount of MAPP accredited capacity. I have assumed that the avoided units have such firm transmission capacity and included estimates of the cost to obtain firm transmission in the avoided capacity cost estimates. The proposed Java Wind Project has completed an interconnection study, but I am not aware of any firm transmission studies that have been done. If the proposed Java Wind Project does not have firm transmission, Superior should not receive avoided capacity payments, since the capacity provided by this project would not be comparable to the firm capacity Montana-Dakota would avoid.

Q. Is Montana-Dakota responsible for obtaining firm transmission for the proposed Java Wind Project?

A. No. Montana-Dakota is not responsible for obtaining firm transmission capacity for the proposed Java Wind Project and should not be responsible for any costs associated with obtaining firm transmission capacity for the proposed Java Wind Project.

5. Avoided capacity payments

Q. How might this avoidable capacity cost be used to calculate capacity payments in a PPA with the proposed Java Wind Project?

A. I provide more detail on this in the later portion of my testimony and in the draft PPA terms. Montana-Dakota should make monthly capacity payments to the proposed Java Wind Project, based on the calculations above.

B. AVOIDED ENERGY COSTS

Q. What is the basis for avoided energy costs?

A. The avoided energy costs for the proposed Java Wind Project should be the energy costs that are avoided by Montana-Dakota as a result of changes to the Montana-Dakota system as a result of the proposed Java Wind Project wind project. In general, this means that the Montana-Dakota system with the purchases from the proposed Java Wind Project system and related payments for avoided energy should not result in increases in the total energy cost of the Montana-Dakota system. I consider the Montana-Dakota avoided energy prices in two situations: Stipulated avoided energy costs prior to the MISO market operation and market-based avoided energy costs after the MISO Day 2 market is in operation.

Q. What is the difference between stipulated avoided energy costs and market-based avoided energy costs?

A. Stipulated avoided energy costs are those that are estimated and included in the long-term contract when that contract is executed. Aside from the difficulty of making accurate estimates of Montana-Dakota's avoided energy costs ten or more years in the future, the situation at Montana-Dakota and the factors driving avoided energy costs are likely to change over the term of a QF contract in ways that cannot be fully or accurately anticipated and modeled before a long-term contract is signed, placing significant risk on Montana-Dakota and its customers.

Market-based avoided energy costs are those that result from Montana-Dakota's participation in the MISO Day 2 electricity market. These amounts will be determined in the period when the energy is avoided and will reflect the regional energy market.

1. **<u>Stipulated avoided energy costs</u>**

Q. What is your recommended approach for stipulated avoided energy costs?

A. Two model runs should be made, one with the proposed Java Wind Project purchases and one without the proposed Java Wind Project purchases. I refer these to the QF-In case and the QF-Out case. The QF-In case should include:

- Energy purchases that will replace energy from other sources
- Capacity expansions of Montana-Dakota are reduced by the avoided capacity amount (ie, 7 MW).

Q. How can a model run take place when the output of the proposed Java Wind Project is uncertain and intermittent?

A. Wind generation has intermittent output, with the actual amount that will be generated in an hour cannot be known until after the hour has passed. In spite of this problem, the estimated output of the proposed Java Wind Project provided by Superior, based on wind speed data, is used in each year of a long-term model run to estimate avoided energy costs for the entire contract period prior to contract execution.

Q. Would such an incremental energy study capture all effects of wind purchases?

A. No. The PROSYM model provides a simplified hourly analysis of dispatch and variable production costs. The simulation, as conducted to determine stipulated avoided energy costs, assumes that the wind energy input is firm and at the hour-by-hour level specified in the inputs. This analysis does not reflect the impact on the Montana-Dakota system from uncertain hourly wind output or from wind output that varies during any hour. The Montana-Dakota system must be operated in a manner that adapts to this unknown level of wind generation in several time frames. In the discussion below of actual impact of wind generation, I discuss the impact of intermittent generation.

Q. Have you done an analysis to estimate the stipulated avoided energy costs for the proposed Java Wind Project?

A. Yes. My estimates of these stipulated avoided energy costs are provided as Exhibit EDK-5. As explained in this Exhibit, these numbers are the result of a PROSYM runs done by Montana-Dakota under my direction that adopt the QF-In and QF-Out methodology that I discuss above.

2. Market-based avoided energy costs

Q. How will the operation of the MISO electricity market change Montana-Dakota's marginal energy costs?

A. When the MISO market is in operation, Montana-Dakota will be operating in a market where there is a spot market for sales and purchases at the margin. If Montana-Dakota has the capability to generate more energy in an hour than is needed in its own system, it can offer that energy to the MISO market and sell it at the spot market price. If the spot market price is at or above Montana-Dakota's marginal cost of generating this energy, Montana-Dakota profits. Montana-Dakota could also make purchases of energy at the margin if the MISO spot market price were lower than the Montana-Dakota marginal cost of generating energy. Thus, Montana-Dakota's marginal costs will become the MISO spot market prices. Further, the locational aspect of the MISO spot market means that using the Locational Marginal Price (LMP) for the location at which the proposed Java Wind Project is located would provide an energy price that is locationally specific.

Q. How would this shift to a MISO market change the Montana-Dakota Avoided Energy Costs?

A. I recommend that the MISO spot market sets the Montana-Dakota Avoided Energy Costs and the associated payments to the proposed Java Wind Project when the MISO market is operational. As discussed above, this approach was adopted in California and Texas. These two states established precedents for the SDPUC to take a similar approach in this Proceeding. There is a significant benefit to Montana-Dakota and its customers from such an approach, as this approach removes the financial risk that is presented by a contract with stipulated avoided energy costs for 10 or more years in the future that are calculated in 2005.

Q. Would the proposed Java Wind Project receive any capacity payments as a result of receiving MISO spot market prices for avoided energy?

A. Yes. The nature of the MISO spot market is that it is a single price market (ie, all energy sold and purchased in an hour is sold and bought at the same market-clearing price). In a single price market, the market-clearing spot price provides significant contributions to fixed costs for generators that have variable costs that are lower than the market-clearing price. The proposed Java Wind Project would receive such amounts in avoided energy payments after the MISO Day 2 electricity is in operation and the MISO spot prices are the basis for avoided energy payments. To the extent that the proposed Java Wind Project is receiving avoided capacity payments, these market-based avoided energy payments may mean that Montana-Dakota is paying twice for the same avoided capacity.

Q. How have you addressed this potential double payment for avoided capacity?

A. When the proposed Java Wind Project is receiving market-based avoided energy payments, these payments will be made only to the amount of generation that is in excess of the amount that would have been produced by the avoided capacity. To implement this, the market-based energy payments in Period 3 have two components: (a) a payment that is based on the variable costs of the avoidable coal unit for energy that is less than or equal to the avoided capacity amount (initially at 7 MW) with a capacity factor of 85%; and (b) any excess energy at the market-based avoided energy price.

3. Avoided energy payments

Q. How might the avoided energy costs be included in a PPA with the proposed Java Wind Project?

A. The PPA would include the following items related to avoided energy payments:

- The stipulated avoided energy prices would be calculated for the entire PPA term, with on-peak and off-peak Summer and Winter amounts, and included as a Schedule to the PPA
- The avoided energy payments would be based on the stipulated avoided energy prices until the MISO Day 2 electricity market is operational
- After the MISO Day 2 electricity market is operational, avoided energy payments would be based on the hourly load-weighted average MISO locational spot price for Montana-Dakota and in Period 3, the payments are composed of (a) a payment that is based on the variable costs of the avoidable coal unit for energy that is less than or equal to the avoided capacity amount (initially at 7 MW) with a capacity factor of 85%; and (b) any excess energy at the market-based avoided energy price.

I provide more detail on this in the PPA terms section.

C. ACTUAL IMPACT OF WIND CAPACITY

Q. What effect would the proposed Java Wind Project have on the Montana-Dakota system?

A. As discussed above, the proposed Java Wind Project would generate energy and may provide some contribution toward Montana-Dakota's MAPP contingency reserve requirements. In addition to meeting the MAPP contingency reserve requirements, Montana-Dakota must also operate its system in real-time to meet customer demand and to maintain system frequency. To accomplish this, Montana-Dakota must have flexible and dispatchable generation plant capacity that can be scheduled on a day-ahead basis to meet Montana-Dakota's expected load, that can be scheduled on an hour-ahead basis to reflect any changes in the day-ahead load, that can be dispatched on a 5-minute basis to follow load within each hour, and that is available to maintain frequency on a real-time basis. Wind capacity's intermittent, largely unpredictable and non-dispatchable output has the effect of increasing the need for conventional dispatchable generation. I attach a recent industry journal article that discusses this effect, "The Costs of Wind's Variability: Is There a Threshold?" Electricity Journal, Jan/Feb 2005, Pages 69-77, as Exhibit EDK-6.

Q. Do you suggest that adding wind capacity to the Montana-Dakota system may increase Montana-Dakota's costs?

A. Yes. As Exhibit EDK-6 discusses, even a small amount of wind will increase the need for generation balancing and regulation reserves. I have attached the study, "Xcel Energy and the Minnesota Department of Commerce Wind Integration Study - Final Report" dated September 28, 2004, as Exhibit EDK-7. This study estimated that the integration costs from adding wind to a utility system is about $4.60 per MWH.

Q. Could the cost imposed by wind generation be even higher?

A. Yes. The study in Exhibit EDK-7 assumed that no additional investments in generation resources (eg, fast-response and load following units) would be required as a result of wind purchases, so that the costs estimated were related only to the inefficient operation of existing generation resources. In most utility systems, this assumption may be acceptable if only a small amount of wind is added to the system.

However, adding more wind to a utility system may mean that the purchasing utility will have invest in capacity additions (ie, fast-response and load following generation) to meet the increased need for scheduling, load following and regulation as a result of wind capacity. Even small amounts of wind generation may also make such investments necessary if the purchasing utility has little spare generation of the type that is used to regulate and balance load.

Q. How would this change when the MISO market is in operation?

A. In the MISO market, Montana-Dakota is intending to self-schedule its generation to meet its expected load in both the day ahead and real-time markets. The intermittent output of the proposed Java Wind Project may mean that Montana-Dakota will buy or sell energy in the spot market that it did not expect to buy or sell. If Montana-Dakota is "net short" (ie, as a result of wind output lower than expected) in periods of high spot prices, the cost of purchasing the extra energy will be high. If Montana-Dakota is "net long" (ie, as a result of wind output higher than expected) in periods of low spot prices, the price received for energy sold will be low. There is also the possibility that Montana-Dakota may be assessed other charges (eg, Uninstructed Deviation charges) related to the incorporation of the proposed Java Wind Project and its intermittent output into the Montana-Dakota system.

Q. How would you recommend that Montana-Dakota address this issue?

A. I recommend that Montana-Dakota should adjust payments to the proposed Java Wind Project to make Montana-Dakota and its customers indifferent to the effect of the proposed Java Wind Project. This adjustment to payments should be included in the PPA with the proposed Java Wind Project. Based on the analysis in Exhibit EDK-7, a Wind Integration Adjustment of $4.60 per MWH, as escalated from 2004, should be included in the proposed Java Wind Project PPA so that

Montana-Dakota can recover the cost of integrating the output of the Java Wind Project into the Montana-Dakota system. Montana-Dakota should also be allowed to collect any other identifiable costs that are incurred as a result of the proposed Java Wind Project.

Q. How would Montana-Dakota collect this amount from the proposed Java Wind Project?

A. I recommend that the Wind Integration Adjustment and any other identifiable costs incurred as a result of the proposed Java Wind Project be included in the PPA as reductions in the monthly payments for energy and capacity made to the proposed Java Wind Project. This approach is consistent with the provisions in PURPA Section 292.304 (e), which allow QF payments to reflect the unique nature of the QF capacity and energy. Reducing the payments to the proposed Java Wind Project by these amounts will ensure that Montana-Dakota and its customers are not worse off because they are buying wind power.

IV. ISSUE 7 – POWER PURCHASE AGREEMENT

Q. What does this section of your testimony cover?

A. In this section of my testimony, I provide a discussion of a number of issues that are related to any Power Purchase Agreement ("PPA") that may be the result of this Proceeding.

Q. Has Superior presented a PPA to Montana-Dakota?

A. No. Superior did not propose a PPA in the discussions with Montana-Dakota that occurred prior to this Proceeding and has not included a PPA in direct or supplemental direct testimony.

Q. Did Order F-3365 require Montana-Dakota to develop a standard PPA for large QFs?

A. No. The development of a PPA for QFs greater than 100 KW was explicitly left to negotiation between the QF and the purchasing utility. As discussed above, Order F-3365 provides some limited guidance on some of the terms, primarily prices, but declines to provide any guidance on how a negotiation of a PPA should occur or on the details of other terms and conditions of a PPA.

Q. Is this issue set for consideration in this hearing?

A. Yes. Issue 7 of the SDPUC Order establishing this Proceeding does this.

Q. Why is it important to provide a full PPA?

A. The PPA is the legally binding contract between the QF and the purchasing utility. All aspects of the transaction must be included in the PPA. Prices in a PPA are only one part of a set of terms and conditions that determine a power sale. The non-price terms and conditions can be as important to both parties as the prices in the PPA. Until the parties in this Proceeding have identified all the issues in such a PPA, any disputes regarding those issues will not be identified and discussed. I consider it unlikely that the SDPUC's role in resolving "contract disputes" under Order F-3365 and under Item 7 of the Order establishing this Proceeding would be completed until Montana-Dakota and Superior have fully considered a complete PPA.

A. <u>TERM OF PPA</u>

Q. What is your recommended term of the proposed Java Wind Project PPA?

A. Ten years.

Q. Why this term?

A. This term fits with the Order F-3365 definition of a long-term contract (ie, 10 years or more). This term also reflects an appropriate balance between the desire of Superior for a long-term stipulated price sales agreement and the risks presented to Montana-Dakota and its customers from such an agreement. Long-term contracts, especially those at prices determined and fixed at the time of contract signing, present significant risk of payments above avoided costs (with no remedies to the purchasing utility) or stranded costs.

B. PAYMENT PROVISIONS

Q. What are your recommendations on payment provisions in the proposed Java Wind Project PPA?

A. As discussed above in the section of my testimony on avoided costs, I propose the following payment provisions:

- Capacity payments that the avoided capacity amount (ie, 7 MW) times the levelized capacity price, subject to the performance provisions discussed below.
- Energy payments divided into Stipulated avoided cost payments (for the period prior to MISO market operation) and Market-Based avoided energy cost payments (after the MISO market is in operation)
- After the MISO Day 2 electricity market is operational, avoided energy payments would be based on the hourly load-weighted average MISO locational spot price for Montana-Dakota and in Period 3, the payments are composed of (a) a payment that is based on the variable costs of the avoidable coal unit for energy that is less than or equal to the avoided capacity amount (initially at 7 MW) with a capacity factor of 85%; and (b) any excess energy at the market-based avoided energy price.
- Monthly payments for energy and capacity would be reduced by an inflation-adjusted amount of $4.60 per MWH to reflect the additional cost imposed on the Montana-Dakota system for regulating its system with wind energy purchases

- Monthly payments for energy and capacity would be reduced by the amount of other costs related to generation balancing imposed on the Montana-Dakota system by wind energy purchases

C. PERFORMANCE PAYMENT PROVISIONS

Q. What are performance provisions?

A. The PPA assumes that the proposed Java Wind Project is actually constructed and that it operates as represented in the discussions leading up to this Proceeding and as represented in the materials filed in this proceeding. To the extent that this is not the case, Montana-Dakota must be sure that it does not pay the proposed Java Wind Project for performance that has not been provided by Superior. Accordingly, the PPA should contain a set of provisions that condition Montana-Dakota's obligations on specific performance by the proposed Java Wind Project.

Q. What performance provisions do you recommend?

A. I recommend the following performance provisions in the proposed Java Wind Project PPA:

- **Operation date** – the PPA, including the payment terms, are developed with the assumption that the proposed Java Wind Project is operational by the end of 2005. All PPA payment provisions would be revised if the commercial operational date occurs after 1 June 2006. Also. Montana-Dakota will have the option of terminate the PPA if the operational date of the proposed Java Wind Project is more than 6 months after its originally scheduled commercial operation date.

- **Demonstrated capacity** – the capacity payments under the contract are based on the assumption that the MAPP accredited capacity during Montana-Dakota's peak period is at the levels that were estimated by Superior for the proposed Java Wind Project.

  - The capacity payments in the period before the proposed Java Wind Project receives actual MAPP monthly accredited capacity during the summer peak period will be based on the current estimates of proposed Java Wind Project capacity of 7MW

- After the proposed Java Wind Project is operational and has received actual MAPP monthly accredited capacity, the capacity amount will be based on the minimum MAPP accredited monthly capacity during Montana-Dakota's summer peak months (ie, June, July, August and September) in the prior year. This means that the Project's Avoided Capacity Payments in each year will be linked to the Project's MAPP accredited capacity set in the prior year; this could result in the Avoided Capacity Payments being either lower or higher than the payments with a stipulated avoided capacity amount of 7 MW.

- If the first actual MAPP accredited capacity amounts during the simmer peak are lower than 7 MW, a refund of avoided capacity payments in prior months will be made.

- If the proposed Java Wind Project does not obtain firm transmission, no avoided capacity payments will be made.

- **Energy payments** – the proposed Java Wind Project will have metering that allows the output to be measured in real-time, so that stipulated energy payments will have an on-peak and off-peak component and the actual output in these periods will be compensated. This ensures that only on-peak deliveries are paid on-peak prices. Avoided energy payments will be made based on stipulated avoided energy prices until the MISO Day 2 electricity market is operational, after which time the avoided energy payments will be based on MISO spot prices

- **Wind Integration Adjustment** – payments to the proposed Java Wind Project will be adjusted by the amount of $4.60 per MWH, as escalated, for the cost of integrating intermittent wind energy into the Montana-Dakota system

- **Reduction of payments for other Identifiable costs** – the proposed Java Wind Project will be required to provide Montana-Dakota with its output on a day-ahead and an hour-ahead basis, so that Montana-Dakota can carry out its generation scheduling activities. To the extent that the proposed Java Wind Project's projected output is significantly different than actual output, Montana-Dakota will have the right to recover any uninstructed deviation charges assessed on it by MISO from the proposed Java Wind Project.

- **Operation to the end of PPA** – the PPA avoided capacity prices are based on the operation of the proposed Java Wind Project for the entire term of the project. As discussed above, the levelized (ie, front loaded) prices will not be appropriate if the proposed Java Wind Project is abandoned prior to the completion of the entire contract term. The proposed Java Wind Project will post an amount of security with Montana-Dakota that will make Montana-Dakota and its customers whole in the event that the proposed Java Wind

Project is abandoned. This security amount will change from year-to-year to reflect the actual exposure of Montana-Dakota.

D. RISK MANAGEMENT PROVISIONS FOR MONTANA-DAKOTA

Q. What are risk management provisions?

A. This PPA presents some degree of risk to Montana-Dakota and to its customers. The following provisions are meant to manage those risks:

- **Regulatory Termination** – this provision would allow Montana-Dakota to terminate the PPA in the event that Montana-Dakota were not allowed to recover the costs incurred as a result of the PPA by the Montana, North Dakota, or South Dakota state utility commissions.
- **Buy-out** – Montana-Dakota should have the flexibility to terminate this contract at any point, with the payment of an appropriate and fair buy-out amount, so that it can limit its exposure to unforeseen changes in the electricity markets. The buyout price will be an amount that is determined at the execution of the contract and is related to the as-yet unpaid capacity payments.
- **Curtailment** – Montana-Dakota may face periods when the operation of the proposed Java Wind Project will cause significant scheduling or balancing problems. In these events, Montana-Dakota would have a right to curtail (partially or totally) the output of the proposed Java Wind Project unit. The curtailments will be limited to a maximum amount per year, above which the proposed Java Wind Project will receive compensation. Montana-Dakota will also have the right to unlimited curtailment without compensation during system emergencies.
- **Assignment** – Montana-Dakota has undertaken significant due diligence on the proposed Java Wind Project and its financial status prior to executing a PPA. Montana-Dakota will retain a right to approve of all assignments of the PPA, including the right to terminate if there is a change in the financial structure of the proposed Java Wind Project without Montana-Dakota approval.

E. SIZE OF THE PROPOSED JAVA WIND PROJECT

Q. What is the issue with respect to size?

A. The documents provided by Superior have suggested a range of project configurations and sizes. It is important that Montana-Dakota establish the actual size of the facility to be installed by the proposed Java Wind Project. The size of this facility has ranged from 50.4 MW to 25.5 MW, with a differing number and size of the individual wind turbines. The facility covered by a PPA must be clearly and unambiguously defined. If Superior wants to build additional wind units, these units must be included in a new PPA with appropriate terms and pricing.

Q. What provisions in the PPA would address this issue?

A. The PPA would refer to a well-identified facility and the precise wind turbines that will be included in the facility. The PPA will include an attachment with appropriate maps and identifying information for the 17 wind turbines that will be installed, with sufficient information to allow Montana-Dakota to verify that the wind turbines are as specified in the PPA. The PPA would include express prohibitions against expansion of the Java Wind Project after the PPA is signed.

F. <u>PPA TERM SHEET</u>

Q. Have you attached a term sheet that describes key PPA provisions?

A. Yes. A draft term sheet that includes key PPA provisions is attached as Exhibit EDK-8. I have included a number of items in this Term Sheet that were not addressed in my testimony because these items will likely be included in the final PPA. I expect that these terms will be used as the starting point in negotiations between Montana-Dakota and Superior to develop a PPA for the proposed Java Wind Project. The items in this term sheet are intended, when agreed, to be used to modify the EEI Master Purchase and Sale Agreement.

V. REBUTTAL

Q. What does this section of your testimony cover?

A. In this section of my testimony, I provide rebuttal of the testimony of Superior witnesses Slater, Ferguson, and Calaway.

A. SLATER REBUTTAL

Q. Did you review the testimony of Superior witness Kenneth J. Slater?

A. Yes.

Q. What issues do you find with the Testimony of Mr. Slater?

A. I find that Mr. Slater has proposed a number of approaches to the calculation of Montana-Dakota's avoided costs with which I disagree:

- The amount of capacity that is actually avoided by Montana-Dakota
- A requirement for Montana-Dakota to market capacity from the proposed Java Wind Project in non-peak months
- Montana-Dakota's calculation of avoided costs is incorrect (page 12 and 13)
- Opportunity cost of environmental allowances

Q. What did Mr. Slater conclude about the amount of capacity that Montana-Dakota will actually avoid as a result of purchasing power from the proposed Java Wind Project?

A. On page 11 (last Q & A) of Mr. Slater's testimony, he suggests that the amount of capacity that Montana-Dakota will actually avoid is equal to the "average summer month MAPP accredited capacity of the Java Wind Project." As explained above, Montana-Dakota can only avoid its requirement to maintain MAPP contingency reserve by the amount of the smallest monthly MAPP accredited capacity during the Montana-Dakota peak, because Montana-Dakota must meet the MAPP contingency reserve requirements in each peak period month.

Q. What did Mr. Slater say about Montana-Dakota's marketing of the proposed Java Wind Project capacity in off-peak periods?

A. Mr. Slater said, on page 12 (first Q & A), that Montana-Dakota's avoided capacity payments should include an amount for the proposed Java Wind Project capacity in winter months, with these payments based on "short-term seasonal capacity prices." This suggests that Mr. Slater assumes that Montana-Dakota will have an obligation to market the capacity from the proposed Java Wind Project in off-peak periods, to estimate the likely revenue from these sales, then include an off-peak capacity payment related to this revenue as a part of the stipulated prices in a long-term PPA. This suggestion is not consistent with PURPA or with Order F-3365. Mr. Slater seems to be trying to get the best of both worlds, by asking for Montana-Dakota to purchase the output of the proposed Java Wind Project as required under PURPA but also to ask for Montana-Dakota market the capacity of the proposed Java Wind Project. Adding to this improper request, Mr. Slater then suggests that Montana-Dakota speculate about the estimated revenue from these market sales and use these revenue estimates to lock in payments to the proposed Java Wind Project at the time of contract execution.

Q. What did Mr. Slater say about Montana-Dakota's estimate of avoided energy cost being incorrect?

A. Mr. Slater said, on pages 12 and 13, that Montana-Dakota made several errors in its estimation of avoided energy cost.

First, he suggests that the PROSYM model runs that provide Montana-Dakota's marginal energy cost are not appropriate as a measure of avoided energy cost. I have used an approach to estimating avoided energy cost that compares a QF-In and QF-Out model run. The QF-In case will also reflect the removal of the capacity assumed to be avoided by the proposed Java Wind Project. In these model runs, we take the Superior estimated hour-by-hour output and use this output to reduce the Montana-Dakota load. The approach I have used, as described above, is consistent with Mr. Slater's recommended approach of "two PROSYM runs, one without the Java generation, and the other with the Java generation."

Second, Mr. Slater suggests that the avoided energy cost model runs should use as much wind information as is available. I agree with this comment and have used the entire set of estimated output from the proposed Java Wind Project as the basis for the hourly energy amounts in the modeling. Indeed, the modeling approach described above assumes that the hour-by-hour the proposed Java Wind Project output is the mean output over the life of the proposed Java Wind Project, as this profile will be used to develop the avoided energy cost for the entire contract term.

Third, Mr. Slater suggests that the Montana-Dakota approach of dividing the proposed Java Wind Project output in each hour by 1.15 is incorrect. I agree.

Fourth, Mr. Slater suggests that the PROSYM model runs should reflect an updated and most likely Montana-Dakota resource/generation plan. I agree and plan to use the three-Period approach as described above in my testimony on Montana-Dakota avoidable units.

Q. What did Mr. Slater say about including the opportunity cost of emissions allowances?

A. Mr. Slater, on page 13 (last paragraph), suggests that the PROSYM database should "include the cost (or opportunity cost), of atmospheric emission allowances associated with Montana-Dakota generation resources." I agree that all actual variable costs of Montana-Dakota's generation should be included in the PROSYM model runs and all appropriate capital costs (eg, for emissions control equipment) should be included in avoided capacity costs, but do not agree that opportunity costs should be included in these runs. Mr. Slater is unclear on what opportunity costs he thinks should be included and how he thinks that these costs should be included. PURPA does not require avoided energy costs to include opportunity costs.

Q. Has Mr. Slater provided any estimates of Montana-Dakota's avoided energy or capacity costs?

A. Mr. Slater included no such estimates in his direct testimony filed on 7 January 2005. He made some estimates of avoided capacity cost only in his supplemental direct testimony filed on 18 January 2005, but makes no estimates of avoided energy costs.

Q. What is your assessment of Mr. Slater's estimates of avoided capacity cost?

A. Mr. Slater's estimate is based on his assumption that the Lignite Vision 21 coal unit is the Montana-Dakota avoided base load unit. As discussed above, the Lignite Vision 21 unit is currently not the most economic option under consideration by Montana-Dakota. The avoided capacity costs proposed by Mr.

Slater would, if adopted, put an undue burden on Montana-Dakota and its customers and would be inconsistent with PURPA.

B. FERGUSON REBUTTAL

Q. Did you review the testimony of Superior witness Jeff Ferguson?

A. Yes.

Q. What issues do you find with the Testimony of Mr. Ferguson?

A. I note two items in Mr. Ferguson's testimony:

- Superior's Interconnection Agreement
- Java MAPP accreditation

Q. What did Mr. Ferguson say about the Java Wind project's Interconnection Agreement?

A. On page 4, Mr. Ferguson reports that the completed and approved Interconnection Agreement must be refiled. Mr. Ferguson suggests that the refiled Interconnection Agreement will be approved and no additional studies will be required. This assertion has not been supported.

Q. Did Mr. Ferguson provide any indication that Superior had applied for or received firm transmission?

A. No. I have not seen any studies that are related to the acquisition of firm transmission capacity for the proposed Java Wind Project. Absent any firm transmission capacity rights, it is my understanding that the proposed Java Wind Project may receive no MAPP accredited capacity. In any case, Montana-Dakota should only make avoided capacity payments to the proposed Java Wind Project if the project has received firm transmission.

Q. What did Mr. Ferguson say about the Java Wind project's MAPP accreditation?

A. On page 7, Mr. Ferguson describes the MAPP accreditation process and, particularly, the process that will take place in the initial period of operation. Mr. Ferguson confirms my understanding of the MAPP process – that MAPP accreditation is based on actual project metered output. His testimony highlights an important issue – the lack of any real data on the output of the proposed Java Wind Project and the lack of an actual MAPP accredited capacity for the project.

At this time, there is no actual output data for the proposed Java Wind Project and only limited estimates of the project's output based on Superior's theoretical calculations. Therefore, there is no MAPP accredited capacity for the proposed Java wind Project. What Mr. Ferguson presents is his estimate of the proposed Java Wind Project output and his estimate of the MAPP accredited capacity that would result if his estimate of proposed Java Wind Project output were correct. I discuss the potential errors in these estimates earlier in my testimony.

Instead of real output information, Superior has collected wind data from the area where the proposed Java Wind Project wind turbines will be located, then used the generic characteristics of the wind turbines that may be built at this site to convert this wind data into hypothetical output amounts.

The MAPP accreditation process uses actual project output and would reflect such things as outages and output that is less than the theoretical output based on generic turbine characteristics. The MAPP accreditation process will also consider whether there is firm transmission capacity for the project. If actual output is less than Mr. Ferguson estimates, the MAPP accredited capacity will be less than he estimated and Montana-Dakota might be asked to make avoided capacity payments for more capacity than the proposed Java Wind Project will deliver.

C. CALAWAY REBUTTAL

Q. Did you review the testimony of Superior witness Calaway?

A. Yes.

Q. What issues do you find with the Testimony of Mr. Calaway?

A. I note several items in Mr. Calaway's testimony:

- Discussion of wind benefits that are irrelevant to the determination of avoided costs in this Proceeding
- Wind production tax credits
- The size of the Java Wind Project

Q. What did Mr. Calaway have to say about the benefits of wind?

A. Mr. Calaway, on page 9 and 10, provides a discussion of the benefits of wind generation. While Mr. Calaway is obviously a strong advocate of the wind industry, not unexpected given his financial interest in the proposed Java Wind Project, his comments are not relevant to a Proceeding that is about implementing PURPA. My earlier concerns about the potential for these Proceedings to be used as a platform to promote wind energy arise, in part, from this portion of Mr. Calaway's testimony.

Q. What did Mr. Calaway have to say about the wind Production Tax credits?

A. Mr. Calaway, on page 12 and 13, provides a discussion of wind production tax credits.

First, Mr. Calaway confirms my earlier comments about these tax credits being (a) "absolutely critical for the economics of any wind project"; and (b) that these tax benefits are present only in the early stages of the project. He states that the "tax credit can be used to offset the alternative minimum tax credit for the next four years" and that the Production Tax credits expire after ten years. These statements confirm my concern that the proposed Java Wind Project may not be viable after these tax credits end.

Second, Mr. Calaway suggests that there is a one-time opportunity to obtain these credits by putting the proposed Java Wind Project into operation prior to the end of 2005. This is apparently meant to place time pressure on Montana-Dakota and on the SDPUC in this Proceeding. Mr. Calaway neglects to mention that the Production Tax credit was first set to expire in 1999, but has been extended several times since then.

Q. What did Mr. Calaway have to say about the size of the Java Wind Project?

A. Mr. Calaway, on page 13, suggests that there is some uncertainty about the actual size of the proposed Java Wind Project. He cites the MISO interconnection study, that has a capacity of 50 MW, then states that "**right now** (emphasis added) we plan to build only 31 megawatts of capacity..."

Mr. Calaway confirms my concern about the actual size of the proposed Java Wind Project. The proposed Java Wind Project has been represented as a range of different sizes and configurations:

- **50.4 MW** – MISO interconnection study by Burns & McDonnell dated 21August 2003 related to MISO project number G297, Queue 37662-02. On page ES-1, the proposed Java Wind Project is described as "a 50.4 MW wind farm."
- **25.5 MW** – 8 April 04 letter from Superior's attorneys to Montana-Dakota
- **25.5 MW (17 units AT 1.5 MW each)** – FERC QF self-certification filing of 15 April 04 attached to the 11 May 04 Superior complaint in this Proceeding. This filing also states on page 3 that the Facility will have a "gross nameplate capacity **not to exceed** (emphasis added) 51 MW." The filing then states that "The Facility will **initially consist** (emphasis added) of 17 wind turbine generators each having a capacity of 1.5 megawatts."
- **25.5 MW** – 11 May 04 Superior Complaint to the SDPUC
- **25 to 50 MW** – Superior's 6 August 04 responses to Montana-Dakota's interrogatories, response 6, page 10; "The Java wind power project is **initially contemplated** (emphasis added) to have an installed generating capacity of 25 MW to 50 MW."
- **31.5 MW (21 units at 1.5 MW each)** – FERC QF self-recertification filing of 23 August 04 (Exhibit 5 to Mr. Calaway's 7 Jan 05 testimony). Note that this change did not modify or remove the "not to exceed 51 MW" language in the 14 April 2004 filing.
- **30.6 MW (17 units at 1.8 MW each)** – Table 1 in Mr. Ferguson's 7 Jan 05 testimony (page 6).

Q. Why is the size of the proposed Java Wind Project an issue?

A. Montana-Dakota will expect to sign a PPA with a single facility that has a well-defined size and project configuration, not a project for which the size, type of wind turbines, and number of wind turbines is a moving target.

Second, if Superior desires to expand the Java Wind Project, any expansion will be a separate facility and a separate PPA. If this separate expansion project is also a QF, the avoided costs for energy and capacity may be different from the avoided costs in this Proceeding.

Third, Montana-Dakota's system is small and may face some difficulty in scheduling and integrating a large wind project. As Mr. Calaway suggests in his testimony on page 14, a wind project larger than 31 MW may not be within "Montana-Dakota's ability to handle."

Q. Does the uncertainty about the size of the proposed Java Wind Project raise other concerns?

A. Yes. The proposed Java Wind Project is unlikely to be very far along in its development, as shown by the changes in unit design and size in the last year.

VI. CONCLUSIONS

Q. What are your conclusions?

A. I discuss and support these conclusions in my testimony.

- The electricity industry has changed significantly since PURPA and Order F-3365 and these changes should be reflected in this Proceeding
- This Proceeding should not be used to promote wind energy or wind generation development in South Dakota
- Any avoided capacity payments to the proposed Java Wind Project must be no more than the *minimum* monthly MAPP accredited capacity during Montana-Dakota's peak period (ie, 7 MW)
- Any avoided energy costs should be linked to MISO spot market prices when the MISO Day 2 electricity market is operational
- There are important PPA terms that must be agreed between the parties

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE FILING BY SUPERIOR RENEWABLE ENERGY LLC ET AL. AGAINST MONTANA-DAKOTA UTILITIES CO. REGARDING THE JAVA WIND PROJECT)	**EL04-016**

AFFIDAVIT

CITY OF ~~County~~ of ALEXANDRIA
State of VIRGINIA

Edward D. Kee, being first duly sworn, deposes and says that the Testimony of Edward D. Kee submitted in the above-captioned proceeding was prepared by him, with the assistance of others working under his direction and supervision, that he is familiar with the contents thereof, and that the statements set forth therein are true and correct to best of his knowledge, information and belief.

Edward D. Kee

Subscribed and sworn before me
this 31st day of January 2005.

Brett T. Lanagan
Notary Public

My Commission expires: 10/31/2005

Exhibit No. EDK-1

Edward D. Kee CV

Personal Profile

Name — **Edward Kee**

Present Position — Member of PA's Management Group

Consulting Experience

Ed is an expert in the electricity industry, with experience in issues of electricity industry restructuring and market reform, competition policy and market power, electricity market design and implementation, transmission pricing and regulation, and security of supply.

The following is a list of major consulting engagements:

Commission for Energy Regulation, Ireland

PA was retained by CER to conduct a review of the current electricity trading arrangements, to design a new Irish electricity market in line with Irish and EU legislation, and to assist in implementing that new electricity market. Included in this effort is an analysis of the market dominance held by the incumbent utility and the development of a comprehensive market power mitigation scheme. In 2004, the effort shifted to the development of an all-island market, where the Republic of Ireland and Northern Ireland would be a part of a single electricity market. Ed is leading the PA team in this effort.

Ontario Independent Market Operator

Provided analysis and detailed review of the rules and related procedures for the Day-Ahead market and settlement.

New Zealand Electricity Commission

Provided a range of advice to the newly established electricity regulator in New Zealand. One important issue covered in this assignment was the establishment of a "dry-year" capacity intervention mechanism.

Enron Power Marketing, Inc.

Retained by Enron Power Marketing Inc. to submit expert testimony in the FERC Gaming Docket (EL03-180, et al) and other related dockets on matters related to Enron Trading

Strategies.

Enron Power Marketing, Inc.

Retained by Enron Power Marketing Inc. to submit expert testimony on the Enron Trading Strategies, the likely effect of those trading strategies on electricity market prices in 2000 and 2001, and related issues in several proceedings before FERC, including EL02-26 (Nevada Power, et. Al.), EL02-114 (Portland General Electric), and EL02-113 (El Paso Electric).

Edison Electric Institute

Provided advice on limitation of the liability incurred by transmission owners and market operators under FERC's new standard market design. Focus was on the limits of end-use customers to seek compensation from the market operator or the transmission owner in the event of outages.

Trans-Elect, Inc.

Retained by Trans-Elect to assist in the acquisition of transmission companies, in the context of a wider strategy and implementation assistance for this pure-play transmission company.

Boston Properties, Inc. Retained as consulting and testifying expert in a dispute between Boston Properties and its unregulated electricity supplier on issues arising during 2000 and 2001 in the California electricity market.

Enron Corporation Retained as consulting and potential testifying expert in the series of class-action civil disputes arising from the level of wholesale power prices in California in 2000. The class-action cases alleged market power abuse in the California electricity market. Performed analyses of detailed trading data and market outcomes.

Consolidated Edison Retained as consulting expert in a civil litigation case arising from the failed merger between two utility companies. Issues include the level of risk and exposure and risk management policies and practices.

Government of South Australia Economic Advisor to the Government of South Australia in the reform, restructuring, and privatization of the former state-owned electricity industry; a close adviser to the Government, working with a team of attorneys, investment bankers, engineers, and other advisers; played a critical role in communicating with various stakeholders.

This engagement involved the development of a complex industry structure plan to separate the incumbent single utility into three generating companies, the development of a market power mitigation program involving vesting contracts, and gaining the approval of the competition regulator (the ACCC) for the overall package. This work also involved preparing analyses and filings to the ACCC related to alleged abuse of market power by one of the government-owned generating companies.

Government of Queensland, Australia

Provided advice to Treasury and Cabinet on reform of government-owned electricity companies, power contracting, retail competition, the development of the PNG natural gas pipeline, and related energy industry issues.

Government of Victoria, Australia

Provided advice to Treasury and Cabinet on issues related to security of supply, government intervention in the spot market, electricity industry cross-ownership rules and related electricity industry issues. The work on industry cross-ownership rules involved an analysis of the competition effects of the existing state-level cross-ownership restrictions, the likely impact of removing or relaxing those rules, and the intersection of the state rules with federal ACCC jurisdiction on market power issues.

NECA (National Electricity Code Administrator), Australia

Primary consultant in the review of the integration of energy markets and network services. This review considered the extent to which full nodal spot pricing could be applied in the Australian electricity market.

This work involved an analysis of the likely impact on market power due to a move to full nodal pricing, with analyses of several other markets with a nodal pricing approach, including NZ and PJM.

NEMMCO (National Electricity Market Management Company), Australia

Provided advice related to NEMMCO's strategic planning and risk management process and led the development and implementation of inter-regional hedge auctions.

DNIB (De Nationale Investeringsbank Asia Ltd), Australia

Provided advice to DNIB about their participation in the lending consortia to newly privatized gas and electricity retail and distribution companies and generating companies.

Illinois Power

Provided advice related to the status of the Clinton nuclear power plant and whether to restart, retire, or sell the plant. Assisted client in the sale process.

Commonwealth Edison

Provided confidential advice related to the strategy for the company's nuclear power plant portfolio.

US Department of Energy

Provided advice on options to produce a supply of tritium, including analysis of linear accelerator options, commercial reactor options, and the use of dedicated MOX fuel reactors to produce tritium while burning surplus plutonium.

Westinghouse Electric

Managed an extensive litigation support engagement during which expert witness testimony was developed and presented in a series of damage lawsuits brought by electric utilities as a result of nuclear steam generator performance.

INESPAL

Assisted INESPAL, the Spanish government-owned aluminum producer and manufacturer, evaluate power supply options. In the face of deregulation in Spain, INESPAL, considered independent power producers, renewed contracts with the incumbent utilities, and other options to lower power input costs.

EEI - Carbon taxes

Prepared analysis of economic impact of proposed carbon taxes for the Edison Electric Institute, with focus on electric utility industry and electricity prices.

Pacific Gas & Electric Company

Provided expert witness testimony in a case brought by independent power producers against PG&E over the implementation of the power procurement process.

Pacific Gas & Electric Company

Prepared report on the risks and hidden costs associated with the Standard Offer power purchase agreements mandated by the California Public Utilities Commission. Presented testimony before the CPUC on Standard Offer contract improvements.

KP&L/KG&E merger

Provided consulting advice and testimony support in connection with the merger of these two companies. Played a significant role in the preparation of FERC competition testimony and in managing the merger filing with FERC. Managed the FERC merger approval analysis and testimony process to a successful conclusion. This work involved implementation of a pre-Order 642 analysis, witness preparation and responses to FERC and intervenor data requests.

Florida Power Corporation

Provided consulting advice and filed expert witness testimony in a dispute between FPC and a group of independent power producers over power purchase agreement terms and implementation.

Fuji Electric

Investigated commercial feasibility of fuel cells in the US market to determine configuration and cost necessary for successful market penetration. Also analyzed product research and development results to identify likely long-term pricing. Presented results to client in Tokyo.

Dominion Energy

Strategic review of utility non-regulated power subsidiary. Significant changes to the investment decision-making process resulted from this engagement.

Virginia Power

Developed and implemented a major power purchase procurement auction process to evaluate offered power purchase agreements from IPPs. Assisted client in developing procurement strategy, in soliciting and evaluating bids, negotiating agreements with winning bidders, and providing independent assessment to utility regulators.

Pacific Gas & Electric

Provided analysis and advice on the potential acquisition of the

Sacramento Municipal Utility District, including the troubled Rancho Seco nuclear power plant. Provided advice and assistance in the negotiated settlement of the Diablo Canyon rate case.

Middle South Utilities - NOPSI

Participated in a team assisting New Orleans Public Service to analyze and negotiate a potential sale of NOPSI to the city of New Orleans.

Pre PA Experience

2000 PHB Hagler Bailly US

Senior Vice President in Washington Office. Ed joined PA Consulting Group in late 2000, when PA acquired Hagler Bailly.

1997 - 2000 PHB Hagler Bailly - Australia

Vice President. Established Australian consulting practice in late 1997 and served as the leader of the Australian consulting practice. During this period, Putnam, Hayes & Bartlett was acquired by Hagler Bailly.

Client engagements in a wide range of electricity and gas restructuring and market reform issues, including competition policy, transmission pricing and regulation, security of supply, wholesale spot market, and Government involvement in the energy industries. Economic Advisor to the Government of South Australia in the reform, restructuring, and privatization of the former state-owned electricity industry.

1993 - 1997 Putnam, Hayes & Bartlett

Director in the Washington DC office, with client engagements on issues including independent power, nuclear generation, electric and gas utility management and regulation, power plant and company valuation, corporate and project finance, power procurement and a number of litigation assignments.

1990 - 1993 Charles River Associates

Senior Consultant engaged in providing consulting, litigation support services and expert witness testimony to clients in the energy and regulated utility industries.

1989 - 1990 Independent Consultant

Retained by Long Lake Energy, a publicly traded independent power company, to provide strategic advice. Developed corporate and market strategies, prepared bids and proposals for non-utility generation projects, and evaluated investment opportunities for various independent power company clients.

1987 - 1989 McKinsey & Company

General management consultant specializing in the energy sector, providing consulting assistance to electric utilities, major oil and gas companies, power industry equipment suppliers and other companies.

1985 - 1987 Catalyst Energy Corporation

Development Principal performing financial and feasibility analyses to support independent power project investments; Member of management team during a successful public stock offering; led the effort to acquire an industrial cogeneration company and served as the President and Director of the newly formed subsidiary.

1986 Lehman Brothers

Summer associate in the Corporate Finance Department of Lehman Brothers. Co-authored a fairness opinion for a commercial bank merger and was the primary analyst for a $50 million securities underwriting.

1978-1983 US Navy

Nuclear engineer engaged in construction, start-up and testing of the nuclear power plants on the USS Carl Vinson (nuclear aircraft carrier); qualified as Chief Engineering Officer. Temporarily assigned to Assistant Secretary of the Navy for Research and Development.

Education

BS Systems Engineering (with Distinction), US Naval Academy

MBA, Harvard University Graduate School of Business

Expert Testimony

Reliance Energy Standby Charges. Retained by Reliance Energy to prepare an expert report on standby charges that was filed with the Maharashtra Electricity Regulatory Commission (MERC) in April 2004. Issues were related to the sharing of a government-mandated standby power contract with MSEB.

Portland General Electric and Enron Power Marketing, Inc.; Before the US Federal Energy Regulatory Commission, Docket EL02-114, February 24, 2003. Retained by Enron Power Marketing Inc. to submit pre-filed rebuttal expert testimony on the Enron Trading Strategies as they relate to the FERC investigation in this Docket.

El Paso Electric, Enron Power Marketing, Inc., and Enron Capital and Trade Resources Corp.; Before the US Federal Energy Regulatory Commission, Docket EL02-113, February 4, 2003. Retained by Enron Power Marketing Inc. to submit pre-filed rebuttal expert testimony on the Enron Trading Strategies as they relate to the FERC investigation in this Docket.

Nevada Power Company, et al v. Duke Energy Trading & Marketing LLC, et al, Before the US Federal Energy Regulatory Commission, Docket EL02-26, August 27, 2002. Retained by Enron Power Marketing Inc. to submit pre-filed direct expert testimony on the Enron Trading Strategies and their likely effect on electricity market prices in 2000 and 2001 in a proceeding that is considering a request by Nevada Power Company and others that FERC abrogate or reform long-term power contracts signed in 2001.

Idaho Power Company v Boston Properties, Inc., US District Court, Northern District of California, San Francisco, January 2002, Case No. C-01-1293. Submitted expert declaration on issues related to FERC market mitigation in California and its effect on California Power Exchange prices.

National Power Australia LLC v EnergyAustralia, Supreme Court of New South Wales Commercial Division, Sydney, Australia, July 1998. Testified at trial as an expert witness on issues related to Power Purchase and Hedge Agreement implementation and required security.

South Australian Parliament. Testimony before the Economic and Finance Committee of the South Australian Parliament on electricity industry reform and privatization issues, Adelaide, South Australia in July 1998.

March Point Cogeneration Company v. Puget Sound Energy, Inc., U.S. District Court, Western District of Washington, No. C95-1833R, October/November 1997. Testified at trial as an expert witness on issues related to QF contract implementation and damages on behalf of Puget Sound Energy.

Red Hill Geothermal Company, Inc., et al. v. Irby Construction Company, Inc., et al.; Superior Court of the State of California, County of Imperial, No. 74359; October 1996. Plaintiffs, geothermal power producers in the Imperial Valley selling power to Southern California Edison via a high-voltage transmission line, sought damages for lost profits, repair and upgrade costs for transmission lines that failed in a windstorm. Defendants were the transmission line engineers, builders and fabricators. Testified at trial on behalf of defendants on damages, geothermal power plant development and operation, and transmission agreements.

Pennsylvania Power & Light Company (PP&L) v. Schuylkill Energy Resources, Inc. and Reading Anthracite Company; The Court of Common Pleas of Lehigh County, Pennsylvania, Civil Division, File No. 95-C-2810; April 1996. Testified in a preliminary injunction hearing as an expert witness on behalf of PP&L on whether irreparable harm to the seller of power would result if PP&L exercised certain rights under the power sales contract.

Alabama Power Company, et al. v. Tennessee Valley Authority, et al.; United States District Court for the Northern District of Alabama, Southern Division; Civil Action No. CV-96-PT-0097-S; April 1996. Filed an affidavit on behalf of Alabama Power Company on the role of power marketing companies in the electric utility industry and on the arrangement between the Tennessee Valley Authority and LG&E Power Marketing.

Pennsylvania Public Utility Commission: Docket P-870235, Amended Petition of Bethlehem Steel Corporation and Hadson Development Corporation; Docket C-913318, American Power Corporation and CMS Generation Company v. Pennsylvania Electric Company; Docket P-910515, Petition of Cambria Partners; and Docket C-913764, Robert Robinson v. Pennsylvania Electric Company; September 1995. Filed testimony on behalf of Pennsylvania Electric Company in these proceedings. The testimony concerned the pricing of disputed power purchase contracts, following a court decision that struck the use of coal proxy plant avoided costs and remanded the pricing issue to the Pennsylvania Public Utility Commission.

Pennsylvania Public Utility Commission: Docket P-00950915, Petition of Harrisburg Steam Works, Ltd. and Paxton Creek Cogeneration Associates; Docket R-00953346, Pennsylvania Public Utility Commission v. Harrisburg Steam Works; September 1995. Filed testimony on behalf of Pennsylvania Power & Light Company in these proceedings, which concerned the request of a cogeneration facility for modified power sale agreement terms and pricing as a part of the Harrisburg Steam Works rate case. The case settled before hearings.

Orlando Cogen, L.P. v. Florida Power Corporation; and Florida Power Corporation v. Air Products and Chemicals, Inc. Designated as an expert witness on behalf of Florida Power Corporation, the purchaser of power in these cases in 1994. The issues included antitrust allegations and contract disputes about curtailment, capacity payments, and energy pricing provisions. The case settled before trial.

New York Public Service Commission; Case No. 94-E-0136; Petition of Sithe/Independence Power Partners, L.P. for an Original Certificate of Public Convenience and Necessity Authorizing Independence's Proposed Generating Station to Provide Electric Service to Alcan Rolled Products Company and Liberty Paperboard, L.P.; July 1994. Testified on behalf of Niagara Mohawk Power Corporation on the fixed and variable costs of the Sithe/Independence plant and whether retail sales by that plant constituted economic bypass.

State Line Power Associates Limited Partnership v. Orange and Rockland Utilities, Inc.; United States District Court, Southern District of New York; 92 Civ. 5755. Designated as an expert witness by the defendant, Orange and Rockland Utilities, on the issues of non-utility generation project development and feasibility in 1994. Case settled during the discovery phase.

State of California, San Francisco Superior Court; Power Producers Dispute Cases (Judicial Council Coordination Proceeding No. 2654; Contra Costa Superior Court No. C90-05398; San Francisco Superior Court No. 929-870), May 1994. Testified at trial on behalf of Pacific Gas & Electric Company as an expert witness on the issues of damages and project feasibility, evaluating lost profits from non-utility generation projects with allegedly breached contracts to sell power.

State of California, Public Utilities Commission, Docket No. I. 89-07-004. Order instituting investigation on the Commission's own motion to implement the Biennial Resource Plan Update following the California Energy Commission's Seventh Electricity Report (U-39E), May 1992. Testified on the behalf of Pacific Gas and Electric Company on the use of regulatory-out, market-out and termination provisions in the final Standard Offer Number 4 power purchase agreements.

State of Rhode Island, Division of Public Utilities and Carriers, Docket No. D-91-10; Re: Pascoag Fire District, May 1992. Testified on behalf of the Pascoag Fire District (a municipal electric utility) on the extent to which the obligations under an unconditional take-or-pay power purchase contract were the financial equivalent of a debt obligation.

AGA Corporation et al. v. Indeck Power Equipment Co.; State of Michigan, Circuit Court, Iron County, Case No. I-88-3985-CK; December 1990. Testified at trial on the behalf of the defendant, Indeck Power Equipment Co., on the level of damages resulting from Indeck's alleged breach of a contract to develop an industrial cogeneration project.

Presentations

"Implementing the New Irish Electricity Market" with Cathy Mannion of CER, SMi Irish Energy conference, Dublin Ireland, November 28, 2003.

"The Role of Retailers in the Spot Market" AESP Annual meeting, Jacksonville, FL (December 5, 2001)

"Texas Electricity Market: Opportunities for Competitive Energy Markets." Power Markets 2002: Energy Policy and its Impact on Energy Markets, Washington, DC (October 16-17, 2001)

"Super RTOs – How will FERC win the West?" Western Power Trading Forum, Stevenson, WA (October 5, 2001)

"2001 US National Energy Policy" Energy Policy and the Electric Power Industry: Balancing Energy Needs and Environmental Concerns; Energy & Mineral Law Foundation, Cincinnati, OH (September 10-11, 2001)

"Victorian Power: New Market Investment." IBC Conference on the New Era of Power in Victoria, Melbourne, Victoria (June 14, 2000)

"An Economic Review of the National Electricity Market: Predicting the Next Stage." IIR Electricity Trading 2000, Sydney, New South Wales (June 13, 2000)

"Security of Supply in the National Electricity Market." Presentation to Victorian Cabinet Committee, Union officials and Consumer Interest Groups, Melbourne, Victoria (May 25, 2000)

"Ownership and Risk Management: The Case for Privatisation." Queensland Power & Gas Conference, Brisbane, Queensland (May 24 and 25, 2000)

"The Dynamics of the Wholesale Electricity Market." IBC SA Power Briefing Conference, Adelaide, South Australia (April 27 & 28, 2000)

"Infrastructure Risk Management." South Australian Power & Gas Conference, Adelaide, South Australia (April 3 & 4, 2000)

"South Australian Perspective on Interconnectors." IBC Interconnect 2000 Conference, Sydney, New South Wales (March 27, 2000)

"International Experience in Nodal Pricing: Focus on Market Power." IBC Nodal Pricing One-Day Update, Sydney, New South Wales (March 14, 2000)

"Integrating Energy Markets and Network Services." National Power Forum Conference, Melbourne, Victoria (February 21, 2000); also served as Conference Chairman

"Review of First Year of the Electricity Market." South Australian Employers' Chamber of Commerce and Industry, Adelaide, South Australia (February 18, 2000)

"Integrating Energy Markets and Network Services." Presentations to Victorian Government, South Australian Government, Queensland Government, National Generator Forum, Australian Cogeneration Association, and Electricity Retailers Association (December, 1999)

"The US Experience with Nodal Pricing," and **"The NZ Experience with Nodal Pricing."** NECA Forum on the on the Scope for Integrating the Energy Market and Network Services, Sydney, New South Wales (November 22, 1999)

"Draft Regulatory Test For New Interconnectors And Network Augmentations." Presentation to Commissioners and Staff of Australian Competition and Consumer Commission, Canberra, Australian Capital Territory (October 21, 1999)

"Integrating Energy Markets and Network Services (with Nodal Pricing Examples)." NECA Forum on Transmission Pricing, Melbourne, Victoria (September 24, 1999)

"Locational Spot Pricing in the NEM." Presentation to the NECA Board, Sydney, New South Wales (September 21, 1999)

"Electricity Supply Industry Reform." Seminar for NSW Democrat Members of Parliament, Sydney, New South Wales (September 9, 1999)

"Retailer Risk: A US Case Study." NECA / AFMA / IBSA Financial Risks in the Electricity Industry Conference, Sydney, New South Wales (August 31, 1999)

"National Electricity Market Update." SA Power Lease Briefing Conference, Adelaide, South Australia (August 30, 1999)

"South Australian Vesting Contracts." Public Forum sponsored by Australian Competition and Consumer Commission, Adelaide, South Australia (August 16, 1999)

"South Australian Vesting Contracts." Teleconference presentation to Commissioners and Staff of Australian Competition and Consumer Commission, Sydney, New South Wales (June 25, 1999)

"National Electricity Market Update." South Australian Employers' Chamber of Commerce and Industry, Adelaide, South Australia (May 31, 1999)

"Electricity Market Concepts and South Australian Issues." Contestable Customer Forum, Adelaide, South Australia (May 19, 1999)

"Economic Purchasing and the PNG Pipeline." Infrastructure and Economic Policy Committee, Queensland Premier and Cabinet, Toowoomba, Queensland (May 9, 1999)

"Contestable Customer Forum." Adelaide, South Australia (April 19, 1999)

"Contestability Schedule and Transition Tariff Arrangements." Electricity Retailer Briefing, Adelaide, South Australia (April 7, 1999)

"Update on Electricity Industry Reforms." Presentation to Upper Spencer Gulf Common Purpose Group, Port Augusta, South Australia (March 31, 1999)

"South Australian Electricity Market." SA Power Lease Briefing Conference, Adelaide, South Australia (March 30, 1999)

"South Australian Electricity Market - Generation." SA Power & Gas Conference, Adelaide, South Australia (March 17 & 18, 1999)

"Market Power or Market Structure? UK Electricity Market Review." Electricity Supply Association of Australia Regulation Conference, Melbourne, Victoria (February 23, 1999)

"South Australian Electricity Market." Contestable Customer Forum, Adelaide, South Australia (February 11, 1999)

"Briefing on SANI / Riverlink, Pelican Point and Market Issues." South Australian Employers' Chamber of Commerce and Industry & SA Gas and Electricity Users Group, Adelaide, South Australia (December 3, 1998)

"South Australian Generation Market." Presentation to Bidders for New Entry Opportunity, Adelaide, South Australia

(November 30, 1998)

"South Australian Electricity Market." Electricity Retailer Forum, Adelaide, South Australia (October 30, 1998)

"National Electricity Market: State Issues, Regulation, and Timetable for Contestability." Australian Council of Professions, Adelaide, South Australia (October 20, 1998)

"National Electricity Market: State Issues, Regulation, and Timetable for Contestability." South Australian Employers' Chamber of Commerce and Industry, Adelaide, South Australia (October 14, 1998)

"Market Structure & Reform: Regulating Bodies and their Role." Australian Institute of Management, Adelaide, South Australia (September 9, 1998)

"South Australian Electricity Industry Reform and Privatisation." Presentations to Energy Markets Seminar, Property Council of Australia, Local Government Association, and Adelaide Business leaders, Adelaide, South Australia (August and September, 1998)

"South Australian Electricity Industry Reform and Privatisation." Television interview by the Australian Broadcasting Corporation, Adelaide, South Australia (July 2. 1998)

"System Reliability in South Australia." Presentation to Premier and Cabinet of South Australia, Adelaide, South Australia (June 25, 1998)

"Competition Policy and the Electricity Supply Industry." Australian Labor Party MP Seminar, Melbourne, Victoria (February 16, 1998)

"Projecting Market Prices in a Deregulated Electricity Market." IBC; Developing & Financing Merchant Power Plants in the New US Market, New York, New York (September 15-16, 1997)

"Determination of Damages in Cogeneration Claims." IGT Power Sales Contracts in the Industry Restructuring Environment, Chicago, Illinois (September 28, 1995)

"Electric Utility Restructuring: Long- & Short-Term Impact on the Natural Gas Industry." IGT: The Outlook for Natural Gas, Houston, Texas (September 11, 1995)

"Strategies for Competing in the Power Marketplace: The View from the Top." Panel Moderator. Independent Energy Forum, New York, New York (October 25, 1993)

"Independent Power, Over-Capacity and Disallowances: A New Regulatory Compact?" Electricity Generation for the 21st Century Conference, Denver, Colorado (June 25, 1993)

"Economic Shut-Down of Nuclear Plants: Case Studies and Industry Outlook." Power-Gen 92 Conference, Orlando, Florida (November 17, 1992)

"Risk-Shifting and Hidden Costs in Purchasing Nonutility Power." Power-Gen 92 Conference, Orlando, Florida (November 18, 1992)

"Carbon Taxes: Impact on the Electric Utility Industry." Edison Electric Institute Taxation Committee, New Orleans, Louisiana (November 10, 1992.)

"Strategies for an Evolving Generation Industry." EEI/AGA Financial Planning for Public Utilities Conference, Chicago, Illinois (May 18, 1992)

"The Economics of Nuclear Plant License Renewal: A Framework for Decision-making." Power-Gen 91 Conference, Tampa, Florida (December 5, 1991)

"Designing Successful Bidding Programs." Faculty presentation for course on Competitive Bidding for Power Contracts, San Francisco, California (October 7, 1991)

"Designing Successful Bidding Programs." Faculty presentation for course on Competitive Bidding for Power Contracts, New York, New York (May 20, 1991)

"Independent Power Joint Ventures." Presentation to the Management Exchange, Inc. Conference on IPP Contracts and Agreements, Washington, D.C. (June 20, 1990)

"Small Cogeneration Economics." Presentation to the Gas Research Institute Cogeneration and Gas Cooling Seminar, Chicago, Illinois (August 1986)

Publications

"Margadh Aibhléise na hÉireann: A New Electricity Market for Ireland" The *Electricity Journal,* January/February 2004.

"Will Monti Pull the Plug on State Aid?" Business Europe section of Wall Street Journal Europe, December 15, 2003.

"An Emerald Market? A new electricity Market for Ireland" *Power Economics*, 5 December 2003.

"Regulated Businesses: Maximizing Shareholder Value through active management." *PA Viewpoint*, January 2003.

"Will there be trouble ahead?" Australian market report in *Electricity International,* July 2002

"Bush's NEP: chimp or champ?" *Power Economics* July/August 2001

"An uncertain path -- Asian electricity reform in the wake of the California market failure" *Power Engineering International*, September 2001, with Michael Crosetti and John George of PA Consulting Group.

"Privatization and deregulation – moving from monopolies to markets." *PA Viewpoint*, January 2002.

"Vesting Contracts: A Transition Tool." *The Electricity Journal*, July 2001.

"Stranded Purchases?" Non-Utility Power Contracts and Utility Industry Deregulation." PHB Insight (November 1995)

"Still a Lot to Learn About Power Sales." *Private Power Executive.* (September - October 1993)

"[Nuclear] Plant Extinction Exaggerated." *Public Utilities Fortnightly* (January 1, 1993)

"Risk-Shifting and Hidden Costs in Purchasing Nonutility Power." Power-Gen 92 Conference Proceedings (November 1992)

"Economic Shut-Down of Nuclear Plants: Recent Case Studies and Industry Outlook." Power-Gen 92 Conference Proceedings (November 1992)

"The Economics of Nuclear Plant License Renewal: A Framework for Decision-making." Power-Gen 91 Conference Proceedings (December 1991)

"Recovery of Indirect Costs of Transmission Services: Case Studies." Edison Electric Institute (February 1991).

"Bid Policies Overhauled." *Cogeneration and Resource Recovery* (November/December 1990)

"Pumped Hydro: The Solution?" *Cogeneration and Resource Recovery* (November/ December 1990)

"Strategies for an Evolving Generation Industry." *Public Utilities Fortnightly* (September 27, 1990)

"Electric Utility Planning: Integrating Demand-Side Options." Edison Electric Institute (August 1990).

"Small Cogeneration Economics: A Risk Management Approach." *Cogeneration Journal* (March 1987)

Exhibit No. EDK-2
Documents reviewed

MAPP Generation Reserve Sharing Pool Handbook revised 2 April 2003.
2003 Montana-Dakota ND IRP
Superior (Watt, Beckworth & Thompson) letter to Montana-Dakota – 8 April 04
Thelen, Reid & Priest letter to Superior – 13 April 04
Superior letter to Montana-Dakota (Stomberg) – 14 April 04
Superior complaint to SDPUC – 11 May 04
Internal legal memo from Montana-Dakota on Superior documents and contacts – 25 May 04 – privileged and confidential
Superior response to Montana-Dakota interrogatories – 6 August 04
Bound set of Montana-Dakota responses to Superior data request dated 16 July 04 (responses 1 though 28)
Superior response to Montana-Dakota Second Interrogatories – (1 Oct 04] confidential, items 1 & 2
Superior response to SDPUC Staff first interrogatories – 21 Oct 04
Bound set of Montana-Dakota responses to SDPUC Data request dated 23 Sep 04 (response 1 through 23)
SDPUC order establishing proceeding EL04-016 – 26 Oct 04; and Order granting motion to compel in EL04-016 – 27 Oct 04
Montana-Dakota letter to SDPUC and Superior on supplemental information to Superior First Interrogatories – 5 Nov 04
Letter from May, Adam, Gerdes with Fort Peck Tribes contract attached – 12 Nov 04
Letter from Montana-Dakota to SDPUC and Superior with power contracts attached – 3 Dec 04 (confidential)
Superior's Third Interrogatories to Montana-Dakota– 8 Dec 04
Montana-Dakota response to Superior's Second set of interrogatories dated 15 Nov 04 (Superior 2nd Data Requests Dated 11-15-04.pdf)

Superior 1-28 dated 7-16-04 Responses 23 & 28_sent 11-03-0.pdf
Resp 28c Sup V 21 175 SL Cashflow.pdf
Responses to Superior-Avoided Costs 20 Oct 2004.pdf - This file is the narrative explaining the calculation and providing a summary of the results. It is not considered confidential.
Base.dat.SDLambdas(Confidential) - This file is confidential and shall be treated under the terms of the Confidentiality Agreement. It is the PROSYM input file that contains all information for operational characteristics of the generating units and data for purchases from the wholesale market.
Forecast.Id.04-09(Confidential).txt - This file is confidential and shall be treated under the terms of the Confidentiality Agreement. It contains the forecast hour by hour customer demand for 2004 through 2009.
Variable Reference(Confidential).pdf - This file is confidential and shall be treated under the terms of the Confidentiality Agreement. It is a copy of the Variable Reference section of the PROSYM Users Manual which defines the variables used in the PROSYM input file (base.dat.SDLambdas) described above.
Current Montana small QF rates
Current North Dakota small QF rates
Superior testimony: – Prefiled direct testimony of Kenneth J. Slater, with and exhibits KJS-1 through KJS-5 – Prefiled direct testimony of Jeff Ferguson, with 1 exhibit – Prefiled direct testimony of John E. Calaway, with 11 exhibits
Montana-Dakota response to Superior Third Interrogatory – 7 Jan 05 (Montana-Dakota's Response to Superior's 3rd Data Request Dated 12-8-04 (Conf Version).pdf)
Bound folder with SDPUC Order F-3365 and supporting documents (Tabs 1-9)
Bound folder with SD small QF rate filings from 1985 to 2004
Slater supplemental testimony dated 18 Jan 04, with Exhibits KJS-6, KLS-7, and KJS-8

Exhibit No. EDK-3
Avoidable capacity cost
Summary

Period	Year	Annual Avoidable Capacity Cost ($/kW/year)
1	2006	$0.00
2	2007	$68.87
2	2008	$70.35
2	2009	$71.86
2	2010	$73.41
3[1]	2011	$142.86
3	2012	$263.75
3	2013	$263.75
3	2014	$263.75
3	2015	$263.75
3	2016	$263.75
3	2017	$263.75
3	2018	$263.75
3	2019	$263.75
3	2020	$263.75
3	2021	$263.75
3	2022	$263.75
3	2023	$263.75
3	2024	$263.75
3	2025	$263.75

[1] Period 3 starts on 15 June 2011

Exhibit No. EDK-3

Avoidable capacity cost

Period 2 calculations

Unit type:	Leased portable combustion turbines
Lease rate (2005 $ per unit per month)	$500,000
Unit size (MW)	25
Months rented per year	3
Set-up cost (as percent of lease rate)	10%
Inflation rate	2.15%

Year	Lease ($/kW)	Set-up cost ($/kW)	Total avoidable cost ($/kW/year)
2007	$62.61	$6.26	$68.87
2008	$63.95	$6.40	$70.35
2009	$65.33	$6.53	$71.86
2010	$66.73	$6.67	$73.41

Exhibit No. EDK-3
Avoidable capacity cost
Period 3 calculations

NPV of total revenue requirements ($/kW) 2011	$2,606
Annual cost ($/kW/year)	$263.86
Fixed charge rate	14.53

Capital type	Percent	Average Return	Weighted return
Debt	44.278%	8.846%	3.917%
Preferred Stock	4.908%	4.622%	0.227%
Common Stock	50.814%	11.000%	5.590%
	Weighted Average Cost of Capital		9.733%

Other inputs and assumptions

Months in first year (June 15 to end)	6.5
Initial book value ($/kW)	$1,666
Cost to obtain firm transmission ($/kW)	$150
AFUDC ($/kW)	$197
Salvage (% of investment)	0.00%
ITC	$0
Tax basis ($/kW)	$1,619
Depreciation base ($/kW)	$1,816
Book life (years)	35
Base year	2011
Discount rate	9.733%
Property tax rate	1.00%
Tax rate	35.00%
Inflation rate	2.15%
O&M rate	1.95%

Exhibit No. EDK-3
Avoidable capacity cost
Period 3 calculations

Plant Cost $/kW (2011)		**$1,666**		**AFUDC**
Cost of Debt (pre-tax)		**8.846%**		**$197.49**
Cost of Debt (after-tax)		**5.750%**		

Month	S-Curve %	CapEx	Cum CapEx	Interest Exp
Sep-07	1.333	22.21	22	0.11
Oct-07	1.333	22.21	44	0.21
Nov-07	1.333	22.21	67	0.32
Dec-07	2.000	33.32	100	0.48
Jan-08	2.000	33.32	133	0.64
Feb-08	2.000	33.32	167	0.80
Mar-08	2.000	33.32	200	0.96
Apr-08	2.000	33.32	233	1.12
May-08	2.000	33.32	267	1.28
Jun-08	2.333	38.87	305	1.46
Jul-08	2.333	38.87	344	1.65
Aug-08	2.333	38.87	383	1.84
Sep-08	2.667	44.43	428	2.05
Oct-08	2.667	44.43	472	2.26
Nov-08	2.667	44.43	516	2.47
Dec-08	3.333	55.53	572	2.74
Jan-09	3.333	55.53	627	3.01
Feb-09	3.333	55.53	683	3.27
Mar-09	4.000	66.64	750	3.59
Apr-09	4.000	66.64	816	3.91
May-09	4.000	66.64	883	4.23
Jun-09	3.333	55.53	938	4.50
Jul-09	3.333	55.53	994	4.76
Aug-09	3.333	55.53	1,050	5.03
Sep-09	3.000	49.98	1,100	5.27
Oct-09	3.000	49.98	1,149	5.51
Nov-09	3.000	49.98	1,199	5.75
Dec-09	2.333	38.87	1,238	5.93
Jan-10	2.333	38.87	1,277	6.12
Feb-10	2.333	38.87	1,316	6.31
Mar-10	2.000	33.32	1,349	6.47
Apr-10	2.000	33.32	1,383	6.63
May-10	2.000	33.32	1,416	6.79
Jun-10	1.667	27.77	1,444	6.92
Jul-10	1.667	27.77	1,472	7.05
Aug-10	1.667	27.77	1,499	7.18
Sep-10	1.333	22.21	1,522	7.29
Oct-10	1.333	22.21	1,544	7.40
Nov-10	1.333	22.21	1,566	7.50
Dec-10	1.000	16.66	1,583	7.58
Jan-11	1.000	16.66	1,599	7.66
Feb-11	1.001	16.68	1,616	7.74
Mar-11	1.001	16.68	1,633	7.82
Apr-11	1.001	16.68	1,649	7.90
May-11	1.001	16.68	1,666	7.98

Exhibit No. EDK-3

Avoidable capacity cost

Period 3 annual calculations

Year	Net Book Value	20 yr MACRS	Net Invested	Tax Dep.	Deferred Taxes	Debt Return	Equity Return	Book Dep.	Income Taxes	Property Taxes	O&M adder	Revenue Reqm't
2011	$1,816	0.038	$1,816	$62	$13	$39	$57	$28	$20	$18	$36	$210
2012	$1,788	0.072	$1,775	$117	$25	$70	$103	$52	$34	$18	$36	$337
2013	$1,736	0.067	$1,699	$108	$22	$67	$99	$52	$34	$17	$37	$328
2014	$1,684	0.062	$1,625	$100	$19	$64	$95	$52	$35	$17	$38	$319
2015	$1,632	0.057	$1,554	$92	$16	$61	$90	$52	$36	$16	$39	$310
2016	$1,580	0.053	$1,486	$86	$14	$58	$86	$52	$36	$16	$39	$301
2017	$1,528	0.049	$1,420	$79	$12	$56	$83	$52	$36	$15	$40	$293
2018	$1,477	0.045	$1,357	$73	$9	$53	$79	$52	$36	$15	$41	$285
2019	$1,425	0.045	$1,296	$73	$9	$51	$75	$52	$34	$14	$42	$278
2020	$1,373	0.045	$1,235	$73	$9	$48	$72	$52	$32	$14	$43	$270
2021	$1,321	0.045	$1,173	$73	$9	$46	$68	$52	$30	$13	$44	$263
2022	$1,269	0.045	$1,112	$73	$9	$44	$65	$52	$29	$13	$45	$256
2023	$1,217	0.045	$1,051	$73	$9	$41	$61	$52	$27	$12	$46	$248
2024	$1,165	0.045	$990	$73	$9	$39	$58	$52	$25	$12	$47	$241
2025	$1,113	0.045	$929	$73	$9	$36	$54	$52	$23	$11	$48	$233
2026	$1,061	0.045	$867	$73	$9	$34	$50	$52	$21	$11	$49	$226
2027	$1,010	0.045	$806	$73	$9	$32	$47	$52	$19	$10	$50	$219
2028	$958	0.045	$745	$73	$9	$29	$43	$52	$17	$10	$51	$211
2029	$906	0.045	$684	$73	$9	$27	$40	$52	$15	$9	$52	$204

Exhibit No. EDK-3

Avoidable capacity cost

Period 3 annual calculations

Year	Net Book Value	20 yr MACRS	Net Invested	Tax Dep.	Deferred Taxes	Debt Return	Equity Return	Book Dep.	Income Taxes	Property Taxes	O&M adder	Revenue Reqm't
2030	$854	0.045	$623	$73	$9	$24	$36	$52	$13	$9	$53	$197
2031	$802	0.017	$562	$28	($7)	$22	$33	$52	$27	$8	$54	$190
2032	$750	0	$516	$0	($16)	$20	$30	$52	$35	$8	$55	$184
2033	$698	0	$480	$0	($16)	$19	$28	$52	$34	$7	$57	$180
2034	$646	0	$445	$0	($16)	$17	$26	$52	$33	$6	$58	$177
2035	$595	0	$409	$0	($16)	$16	$24	$52	$32	$6	$59	$173
2036	$543	0	$373	$0	($16)	$15	$22	$52	$31	$5	$60	$169
2037	$491	0	$338	$0	($16)	$13	$20	$52	$30	$5	$62	$165
2038	$439	0	$302	$0	($16)	$12	$18	$52	$29	$4	$63	$161
2039	$387	0	$266	$0	($16)	$10	$15	$52	$28	$4	$64	$157
2040	$335	0	$231	$0	($16)	$9	$13	$52	$26	$4	$66	$154
2041	$283	0	$195	$0	($16)	$8	$11	$52	$25	$4	$67	$151
2042	$231	0	$159	$0	($16)	$6	$9	$52	$24	$4	$69	$148
2043	$179	0	$123	$0	($16)	$5	$7	$52	$23	$4	$70	$145
2044	$128	0	$88	$0	($16)	$3	$5	$52	$22	$4	$72	$141
2045	$76	0	$52	$0	($16)	$2	$3	$52	$21	$4	$73	$138
2046	$24	0	$16	$0	($7)	$1	$1	$24	$9	$4	$34	$63
Net Present Value at 2011												$2,606

Exhibit No. EDK-4
Levelized avoidable capacity costs

Discount Rate: 9.73%

	20	15	10	5
Term of PPA	**20**	**15**	**10**	**5**
Levelized payment ($/kW/year)	**$171.27**	**$158.37**	**$129.74**	**$56.57**
Levelized Payment ($/kW/month)	**$14.27**	**$13.20**	**$10.81**	**$4.71**

Period	Year	Annual capacity cost	Discount factor	Present value	NPV	NPV	NPV	NPV
1	2006	$0.00	0.9546	$0.00				
2	2007	$68.87	0.8699	$59.91				
2	2008	$70.35	0.7928	$55.77				
2	2009	$71.86	0.7225	$51.92				
2	2010	$73.41	0.6584	$48.33				**$215.93**
3[2] (A)	2011	$142.92	0.6000	$85.75				
3	2012	$263.86	0.5468	$144.27				
3	2013	$263.86	0.4983	$131.47				
3	2014	$263.86	0.4541	$119.81				
3	2015	$263.86	0.4138	$109.18			**$806.42**	
3	2016	$263.86	0.3771	$99.50				
3	2017	$263.86	0.3436	$90.67				
3	2018	$263.86	0.3132	$82.63				
3	2019	$263.86	0.2854	$75.30				
3	2020	$263.86	0.2601	$68.62		**$1,223.15**		
3	2021	$263.86	0.2370	$62.54				
3	2022	$263.86	0.2160	$56.99				
3	2023	$263.86	0.1968	$51.93				
3	2024	$263.86	0.1794	$47.33				
3	2025	$263.86	0.1635	$43.13	**$1,485.07**			

[2] Period 3 starts on 15 June 2011

Exhibit No. EDK-5

Stipulated avoided energy costs[3]

Year	Annual average ($/MWh)	Winter off-peak ($/MWh)	Winter on-peak ($/MWh)	Summer off-peak ($/MWh)	Summer on-peak ($/MWh)
2006	17.39	16.59	18.02	16.16	17.70
2007	22.22	21.15	21.76	20.40	22.49
2008	20.57	20.11	21.19	19.51	20.80
2009	21.07	20.78	21.71	20.06	21.26
2010	21.79	21.02	21.37	20.32	22.01
2011	17.83	18.07	19.49	17.53	17.99
2012	15.97	15.20	15.84	14.54	16.17
2013	17.32	16.67	17.32	15.90	17.54
2014	16.65	15.84	16.70	15.33	16.89
2015	17.01	16.33	17.28	15.63	17.24
2016	16.92	16.07	17.08	15.53	17.18
2017	18.45	17.60	18.68	16.89	18.73
2018	18.06	17.30	18.37	16.57	18.30
2019[4]	18.33	17.48	18.55	16.70	18.59

[3] The separation of the annual average amounts in this Exhibit into seasonal on-peak and off-peak periods is a preliminary estimate based on PROSYM marginal energy costs. Actual amounts will, when calculated, be provided in a supplemental filing.

[4] Should this Proceeding result in a PPA term that extends beyond 2019, the PROSYM model will be modified and used to calculate stipulated avoided energy costs beyond 2019 that will be provided in a supplemental filing.

Exhibit No. EDK-6

"The Costs of Wind's Variability: Is There a Threshold?"

Electricity Journal, Jan/Feb 2005, Pages 69-77

The Costs of Wind's Variability: Is There a Threshold?

Managing wind's intermittency entails costs even when wind power supplies a small fraction of load. If electric power systems evolve efficiently as wind capacity grows, the costs of managing intermittency will grow smoothly with increasing penetration, allowing wind power to provide deep reductions in CO_2 emissions at costs that are competitive with other mitigation options.

Joseph F. DeCarolis and David W. Keith

Joseph F. DeCarolis, *who recently obtained a Ph.D. at the Department of Engineering and Public Policy at Carnegie Mellon University in Pittsburgh, recently accepted a post in Research Triangle Park, NC, in the Atmospheric Protection Branch of the Office of Research and Development at the Environmental Protection Agency (decarolis.joseph@epa.gov).*

David W. Keith *holds the Canada Research Chair in Energy and the Environment in the departments of Chemical and Petroleum Engineering and Economics at the University of Calgary, where he works on climate-related energy-technology, science, and related public policy. His recent work has focused on the capture and storage of carbon dioxide and the economics and climatic impacts of large-scale wind power. He can be contacted at keith@ucalgary.ca; his Web site is www.ucalgary.ca/~keith.*

The work described in this article was not funded by the U.S. Environmental Protection Agency, nor has the article been reviewed by the Agency. The contents reflect the views of the authors alone, not those of the Agency, and no official endorsement should be inferred.

I. Introduction

Global wind power capacity is roughly 40 GW, with annual capacity additions approaching 8.2 GW and annual equipment sales exceeding $9 billion.[1] Construction of wind farms has been driven by government regulation or subsidies in combination with steady declines in unit costs. At good sites, the average cost of wind power at the turbine is currently 4–6 ¢/kWh without credits or subsidies, and advances in turbine design may plausibly reduce the cost to 3 ¢/kWh within two decades.[2] Although wind energy currently serves about 0.1 percent of global electricity demand,[3] it has the fastest relative growth rate of any electric generating technology: capacity has increased by roughly 30 percent annually for the five years ending in 2002.[4]

Two factors—the spatial distribution and intermittency of wind resources—raise the effective cost of wind above the average cost of electricity from a single turbine. In this article, we focus on understanding how the cost imposed by wind's intermittency scales with the amount of wind power in an electric power system. Many authors assert, either implicitly or explicitly, that a threshold exists (expressed as

 1040-6190/$–see front matter doi:/10.1016/j.tej.2004.12.006

the fraction of demand served by wind energy), below which wind imposes negligible costs on grid operation and above which wind imposes substantial costs. Perhaps the most important role for wind power is in supplying electricity without CO_2 emissions. Long-range energy system models used in climate policy analysis often limit the penetration of wind power in response to carbon constraint using such thresholds. We contend that no such threshold exists. Wind's intermittency imposes non-negligible costs even when wind serves only a tiny fraction of demand, but if the electric power system evolves as wind capacity is added, these costs grow monotonically from zero and need not be prohibitive even when wind serves more than half of demand.

II. Background: Managing Variability in Electric Power Systems

Wind must be converted to electricity where wind resources are located. While not addressed here, the spatial distribution of wind resources will often require long-distance transmission lines that increase the cost of electricity from wind.[5,6] Unlike conventional capacity, wind-generated electricity cannot be reliably dispatched or perfectly forecasted, and exhibits significant temporal variability. The uncontrollable nature of wind makes it less valuable to system operators than dispatchable power. In restructured electricity markets, for example, wind operators choosing to participate in markets for scheduled energy may have to settle schedule deviations at the real-time price, which decreases revenue.[7,8] Such penalties are not simply arbitrary financial mechanisms, but reflect, however imperfectly, the cost of managing variations in wind output.

Even without wind, managing electric supply and demand requires sufficient flexibility to respond to time-varying demand, forecast inaccuracies, and contingencies. Three time scales concern system operators on a day-to-day basis: minute-to-minute, intra-hour (5–60 minute time scale), and inter-hour. System operators typically schedule energy each hour using economic dispatch to meet forecasted demand. The schedule is typically drawn up the day before scheduled dispatch. Sub-hourly differences between scheduled energy and forecasted demand during each hour are met by load-following units that can ramp output quickly to balance supply and demand. In restructured electricity systems, load-following units participate in a real-time (intrahour) market. For example, the New York, New England, and PJM independent system operators (ISOs) determine load imbalance on five-minute intervals and use supply curves to dispatch the load-following units participating in the real-time market.[9] Typically, any generating unit deviating from its schedule must pay the imbalance at the real-time price. Load-following units are also known as spinning reserve because they are synchronized to the grid and either idle or operate at less than full capacity.

Even without wind, managing electric supply and demand requires sufficient flexibility to respond to time-varying demand, forecast inaccuracies, and contingencies.

System operators employ an automatic generation control (AGC) system to manage minute-to-minute load imbalances—an ancillary service known as regulation. Units participating in AGC are equipped with governors that sense a change in frequency and automatically adjust output. Intra-hour dispatch every few minutes allows the units providing regulation to return to their nominal set points. There are three important distinctions between regulation and load-following: (1) regulation takes place over a shorter time scale (minute-to-minute versus every several minutes), (2) load centers have uncorrelated variability on the regulation timescale, but exhibit significant correlation on the load-following time scale, and (3) load-following changes often follow predictable diurnal cycles while regulation does not.[10] These time scales are illustrated in **Figure 1**.

 1040-6190/$–see front matter doi:/10.1016/j.tej.2004.12.006

In order to provide AGC and spinning reserve, some generating units must operate at lower power output than would be dictated by optimal economic dispatch without the requirement to follow changing loads; this adjustment forces the system operator to dispatch higher marginal cost units to make up the difference, which raises the average cost of electricity. Additional costs arise from the degraded efficiency that results when generators are operated at partial power or are forced to follow rapidly changing loads.

In addition to making minor corrections to load forecasts or small schedule deviations, system operators must also have enough generating capacity to meet system contingencies, such as a forced outage of a particular generating unit or transmission line. Operating reserve, which consists of spinning and non-spinning reserves, represents capacity that can be dispatched within minutes to meet demand in the event of a system contingency such as failure of a generating unit. Non-spinning reserves consist of quick-start units that are not operating, but can be brought online in a matter of minutes. The requirements for operating reserves are generally set by deterministic criteria, such as a fraction of the forecasted maximum peak demand, to ensure that they are large enough to compensate the most likely or largest contingencies.

III. Wind at Small Scale

Several analyses suggest that there is a threshold below which wind has a negligible effect on

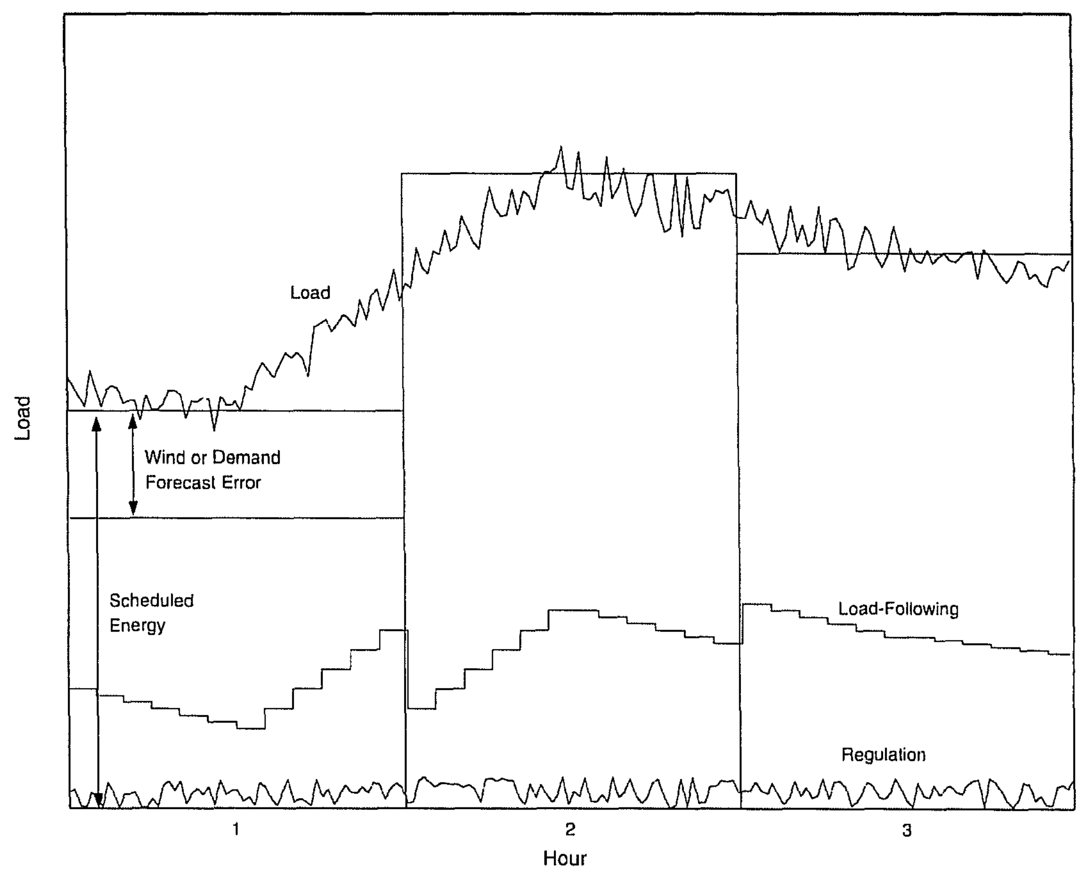


Figure 1: Stylized picture of supply and demand. In most control areas, energy is scheduled ahead of time on an hourly basis according to forecasted demand and unit availability, represented by the three bars. The noisy line represents actual demand and can be separated into the intra-hour load-following and regulation components. Load-following units (spinning reserve) are employed to correct the hourly energy schedule so that supply meets demand on a sub-hourly timescale (every 5–15 minutes), and units equipped with AGC perform regulation to meet the minute-to-minute variability. Regulation and load-following are displayed separately near the bottom of the plot. Inaccuracies in forecasted demand and/or wind can increase the need for load-following capability

 1040-6190/$–see front matter , doi:/10.1016/j.tej.2004.12.006

grid reliability, and therefore imposes negligible costs.[11,12,13,14] Richardson and McNerney assert that "if the generation displacement provided by the wind turbines is within the power-handling capabilities of the load-following units, then wind turbines should not affect system stability." Grubb and Meyer claim that "with no significant measures taken either to make thermal units more flexible, or to predict wind energy better, then serious operational penalties could arise for wind contributions much above 10–15 percent of system energy," and also indicate that variability from wind at low levels of penetration are "drowned out by errors in predicting demand, so there is no operational penalty at low wind penetrations." The European Wind Energy Association (EWEA) claims that "numerous assessments involving modern European grids have shown that no technical problems will occur by running wind capacity together with the grid system up to a penetration level of 20 percent." In a final example, van Kuik and Slootweg claim that wind can serve 15–20 percent of electricity demand "without special precautions to secure grid stability."

These studies implicitly assume that small-scale wind does not affect reserve capacity and does not produce a measurable effect on grid operations. By this logic, wind's variability imposes no costs until it approaches the limit of the existing system's operating reserve capability. This assumption is unrealistic, however, because as we discussed above, anything that adds variability to load or supply—even if uncorrelated with existing load—will impose additional costs if the same level of reliability is to be achieved. If wind is a very small fraction of load then these costs will be small in absolute terms, but they may still be significant when compared to the cost of wind power itself.

It may be difficult, or impossible, to unambiguously partition the cost of wind's variability between various markets and market participants; it is nevertheless possible, at least in principle, to assess the overall cost of wind's intermittency.

It may be difficult, or impossible, to unambiguously partition the cost of wind's variability between various markets (day ahead, real-time, and regulation) and market participants (producers, consumers, and transmission operators); it is nevertheless possible, at least in principle, to assess the overall cost of wind's intermittency.

Suppose an electric power system without wind supplies electricity at an average cost C_0 while wind power can be supplied at average cost C_W.[15] If wind power had the same temporal characteristics (e.g., dispatchability) as the conventional supply then the average cost of power for the combined system would be a simple linear combination of C_W and C_0 as the fraction of total power supplied by wind was increased. In practice, the average cost of electricity in an optimally dispatched system that combines wind and conventional capacity will rise above the simple linear combination of average costs. The system-level cost of wind's intermittency is the difference between actual costs and the linear average cost line that would apply if intermittency were neglected (**Figure 2**). The effective cost of wind power at the margin—including the cost of intermittency—is the derivative of the total cost curve evaluated at zero wind penetration (line A in Figure 2).

Supporting our assertion, Hirst and Hild find that the revenue received by the wind generators declines smoothly and steadily as the percent of wind serving demand increases and attribute the declining payments to several factors: the addition of supply to a small control area, forecast errors, interhour variability, intrahour energy imbalance, and regulation.[16] The authors estimate the marginal system costs imposed by wind, but do not address the issue of whether existing reserves are sufficient to maintain the pre-wind level of grid reliability. We argue that the portion of aggregate variability attributable to wind ties up a fraction of the

 1040-6190/$–see front matter doi:/10.1016/j.tej.2004.12.006

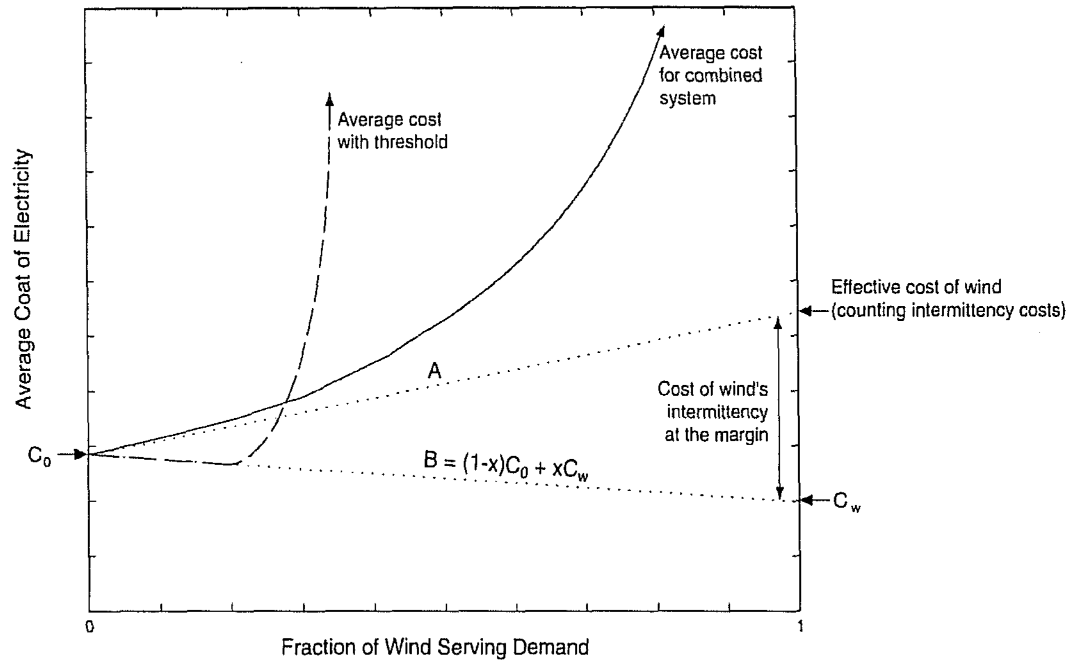


Figure 2: Schematic illustration of the economics of intermittent wind. The vertical axis is the average cost of meeting demand, including both capital and operating costs. The horizontal axis is the total energy supplied by wind divided by the total supplied energy from all generating sources. If wind were dispatchable, then the average cost of power for the combined system would be a simple linear combination of C_W and C_0 as the fraction of total power supplied by wind (x) was increased, as illustrated by line 'B'. Line 'A' includes both the generation cost of wind and the cost of reserve capacity for wind. The curve shows the minimum cost of supplying demand as a function of the amount of wind energy, where we assume that the demand and system reliability are held constant. several studies on the cost of wind power suggest that the cost of intermittency is negligible below some threshold beyond which it rises steeply, as illustrated in the heavy dashed curve

existing regulation and load-following capacity, which reduces the amount of reserve available for system contingencies. If reliability is held constant as wind power is added to the system, this requirement for additional reserve capacity necessarily adds to overall costs.

When wind is a small fraction of demand, operators (sensibly) manage its variability by treating it as negative load, but this does not mean that the cost of variable wind is negligible. Moreover, wind is in several respects more variable than typical loads. At the minute-to-minute or regulation time scale, the AGC requirement can be treated as a random variable with a Gaussian distribution and mean of zero.[17] For a sense of perspective, the regulation component is roughly 0.1 percent of total load in PJM.[18] For comparison, the regulation component for wind in isolation is much larger; one study demonstrates its decline from 10 to 6 percent of rated wind capacity (assuming a 3σ risk level) as the wind capacity grows from 10 to 100 MW.[19] Another study performed in Germany finds that the regulation burden from wind declines from 4.5 to 1 percent of rated wind capacity (or 14.5 to 3 percent assuming a 3σ risk level), for wind capacities of 2.8 and 44.6 MW, respectively.[20] The regulation required for wind grows more slowly than wind capacity because fluctuations on the minute time scale are weakly correlated. In the case of a single wind farm, the minute-to-minute change in each turbine's output is neither perfectly independent nor perfectly correlated with the other turbines. If wind farms are scattered over a large control area, then the regulation requirement for each wind farm is roughly independent of the others, and the total regulation requirement would scale as the square root of the sum of squares from each of the wind farms. For small-scale wind serving less than a few percent of demand, the growth in the regulation requirement for wind can be approximated as linear. But as the level of wind on

 1040-6190/$–see front matter doi:/10.1016/j.tej.2004.12.006

the system increases, the regulation requirement grows slower than wind capacity and the regulation requirement per unit of wind energy decreases. As such, the cost of regulation—while important—is unlikely to place a strong constraint on the future growth of wind.

Wind is also more variable than typical loads at the inter-hourly load-following time scale, and this can lead to underestimates of the cost of wind's variability. Milligan, for example, employs the 3σ rule as a simple proxy to estimate the hourly load-following requirement for wind.[21] (N.B., the actual amount of AGC and load-following capacity must be sufficient to meet NERC's CPS1 and CPS2 reliability standards, respectively, which translates into a different capacity requirement for each system operator depending on the particular characteristics of the control area.) Analysis of PJM aggregate hourly load data suggests that load-following requirements have a sub-Gaussian distribution in which the actual number of hours which exceed the 3σ-rule is much less than the 0.3 percent that would occur if the variability of load were normally distributed, making the 3σ-rule conservative for loads. Inter-hour changes in wind power, on the other hand, have a super-Gaussian distribution.[22] This result suggests that Milligan's analysis may substantially underestimate the amount of load following capacity necessary to maintain system reliability because wind increases system variance and fattens the tail of the load-following distribution. More generally, it cannot be assumed that wind power time series have the same statistical characteristics as load time series. While Hirst and Hild find that the imbalance charge for intrahour load-following is very modest, even with wind serving ~25 percent of

demand, they acknowledge that reliability will be degraded but do not estimate the cost to upgrade reserves.[23] The cost of adding system reserve to cover the higher variance with wind is real and should be accounted for by system planners.

IV. Wind at Large Scale

The discussion above assumed that, except for marginal additions to capital stock to cover AGC and load following, the electric power system remains static as wind is added. This assumption is reasonable for small amounts of wind, but as the fraction of wind serving demand increases, it becomes less plausible. Because wind serving a substantial fraction (e.g., more than a third) of demand will take (at least) several decades to achieve, the mix of generating units is likely to change significantly during this long period of wind development. Studies that assume wind will grow to serve 20 percent of demand or more while the existing infrastructure remains static may falsely produce a threshold. The dashed curve in Figure 2 represents such a scenario: wind added to a static system does not affect cost until a certain threshold, at which intermittency exceeds the system's operational flexibility, and the cost of electricity rises sharply. Any economic limit on the amount of large-scale wind in a given system will depend on how wind coevolves with the rest of the electric power system. All else equal, the cost of intermittency will be less if the generation mix is dominated by gas turbines (low capital costs and fast ramp rates) or hydro (fast ramp rates) than if the mix is dominated by nuclear or coal (high capital costs and slow ramp rates). In many parts of the world, the rapid growth in gas turbine capacity is likely to continue, thereby supplanting older coal capacity and making the economics increasingly attractive for wind. In a non-static system, low cost reserve can also be added to the wider grid to account for the increased variance from wind.

Three factors lower the economic value of wind as the wind penetration level increases,

  doi:/10.1016/j.tej.2004.12.006

assuming a static system: (1) the reduced cost of marginal fuels (increasing wind generally saves fuel from progressively lower fuel cost thermal plant), (2) operational losses (repeated plant starts or partial plant loading), and (3) discarded wind energy (primarily due to operational constraints).[24] Discarded wind energy, even without operational constraints, lowers wind's marginal contribution to serving load as the supply of wind energy exceeds demand and is wasted[25]. The effect of discarded wind energy can be seen in Figure 2, where the average cost of wind diverges upward from the line A.

Grubb defines two (somewhat arbitrary) penetration limits: (1) the marginal fuel savings have dropped by one-quarter and (2) the marginal fuel savings have been halved. Grubb considers (1) to be an economic target and (2) to be a "maximum credible penetration level." In terms of the percent of wind energy serving demand, Grubb finds that (1) is 17 percent and (2) is 26 percent for the British system. However, Grubb assumes a static system, and the results would change significantly—increasing or eliminating the threshold—if the rest of the electric power system was free to change as well.

More recently, we investigated the cost of large-scale wind in a non-static system. We used a time-resolved simulation model in which distributed wind farms interconnected via long-distance transmission lines, storage, and gas turbines meet a time-varying load. The installed capacity of various system components was then adjusted to minimize the average cost of electricity under a carbon tax.[26] In this system, cost of intermittency, as defined above, is only 1–2 ¢/kWh when wind serves 50 percent of demand. Our analysis does not, of course, resolve the issue. In addition to using a (relatively)

simplistic electric system model, our analysis assesses greenfield costs, examining an optimal end-point while ignoring the temporal evolution of the electric power system from a current to future state.

V. Conclusions

Undispatchable wind energy imposes real costs on grid operations, even at the scale of a single wind farm. We posit that these costs increase smoothly and monotonically as the fraction of wind serving demand increases. Studies that assume reserve capacity is free up to a certain threshold are not taking into account the degraded reliability stemming from increased system variance. Even at small scale, wind adds to variable load, which reduces reserve margins by forcing fast-ramping capacity to correct wind-induced imbalances. Threshold arguments for wind are likely to be overly optimistic at low wind penetration levels (by ignoring the degraded reliability stemming from wind intermittency) and overly pessimistic at high wind penetration levels (by assuming that serious operational penalties will suddenly arise in a static system). While it is imperative to consider the system reliability implications of wind at all scales, we do not believe that the addition of operating reserve to the wider grid to counter variable wind will result in prohibitive costs. We stress that the costs imposed by large-scale wind serving more than a quarter of demand cannot be estimated by taking a static system view, but rather will depend on how the underlying system architecture changes over time as the amount of installed wind gradually increases.

We assert that credible estimates of the costs of wind's intermittency must assume that electricity is supplied with the same level of grid reliability with wind as without. While accepting a lower level of reliability could reduce the average cost of supplying electricity with wind power, lower reliability standards would enable roughly equivalent cost savings in the absence of wind. For the same reason, while

  doi:/10.1016/j.tej.2004.12.006

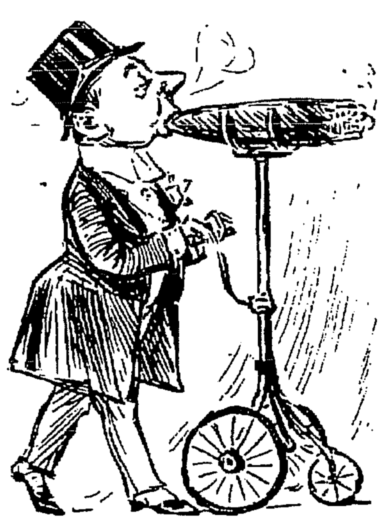
increasing the responsiveness of demand could reduce the overall costs of electric power, such measures entail roughly equal benefits with or without wind. Increasing the responsiveness of demand may make sense, but it is misleading to argue that the costs of wind's intermittency can be reduced simply because lower electricity costs can be achieved by increasing demand-responsiveness or reducing reliability.

The most credible driver for future wind development is a constraint on carbon emissions. Centralized ownership and management, significant experience with regulation, and large, manageable point sources of CO_2 make the electric power sector a prime target for deep cuts in CO_2 emissions. Even with the added cost to deal with intermittency, wind is roughly competitive with other generation technologies under a strong carbon constraint. While air pollution and energy-security are often cited as drivers for wind power, it is less plausible that wind power can provide a cost-competitive means of addressing these challenges.[27]

The role of wind in reducing CO_2 emissions over the long run (decades to a century or more) is addressed by energy-system models that attempt to compute the long-run costs of reducing CO_2 emissions across all economic sectors and energy technologies. Such models are integral to so-called integrated assessment models (IAMs) of climate change that play a central role in debates over long-term climate policy. Such models must necessarily use highly simplified representations of electric power systems and ignore the dynamics of generating system dispatch. These models often assume that there is a strong threshold beyond which wind power becomes uneconomic. In one of the most prominent of such models, for example, the fraction of electricity supplied by wind power is effectively limited to 10 percent.[28]

We suspect that by imposing arbitrary (and generally small) caps on wind power's penetration, such integrated assessment models may greatly understate the potential contribution of wind power to mitigating CO_2 emissions. The outputs of these models, which show comparatively small contributions from wind power, play important roles in debates about appropriate energy policies to manage climate change. It is important to objectively reassess wind's role through critical research on the implications of wind power's variability for large-scale electric power systems; research that connects the typically disparate communities of those who study near-term integration of wind power in existing markets with the community that does long-range energy modeling.

Future research on the intermittency cost of wind should include analysis of high-resolu-



Even with the added costs to deal with intermittency, wind is roughly competitive with other generation technologies under a strong carbon constraint.

  doi:/10.1016/j.tej.2004.12.006

tion demand, supply, and wind power time series, consider plant retirement and the temporal development of the electric power system, and ensure that reliability is held constant as wind is added to the system. An important outcome of such work could be supply curves that provide cost estimates of mitigating carbon emissions with wind that do not impose an exogenous limit on wind development. Such supply curves could serve as input into integrated assessment models to achieve a fairer treatment of wind under a carbon constraint.

Endnotes:

1. American Wind Energy Association, *Global Wind Energy Market Report*. Washington, DC, 2004.

2. Stanley R. Bull, *Renewable Energy Today and Tomorrow*, Proceedings of the IEEE, 89(8), 2001, at 1214–1226.

3. Ralph E.H. Sims, Hans-Holger Rogner, et al., Carbon Emission and Mitigation Cost Comparisons between Fossil Fuel, Nuclear and Renewable Energy Resources for Electricity Generation, ENERGY POLICY, 31, 2003, at 1315–1326.

4. See AWEA, *supra* note 1.

5. Alfred Cavallo, *High-Capacity Factor Wind Energy Systems*, JOURNAL OF SOLAR ENERGY ENGINEERING, 117, 1995, at 137–143.

6. Tom Factor and Tom Wind, Delivering 2,000 MW of Wind Energy to the Metropolitan Centers of the Midwest, Iowa Dept of Natural Resources.

7. Eric Hirst, *Interactions of Wind Farms with Bulk-Power Operations and Markets*, available at http://www.ehirst.com/publications.html.

8. Eric Hirst and Jeffrey Hild, The Value of Wind Energy as a Function of Wind Capacity, ELEC. J., July 2004.

9. See Hirst, *supra* note 7.

10. Brendan Kirby and Eric Hirst, Customer-Specific Metrics for the Regulation and Load-Following Ancillary Services, Oak Ridge National Laboratory, ORNL/CON-474, 2000.

11. R. David Richardson and Gerald M. McNerney, *Wind Energy Systems*, Proceedings of the IEEE, 81(3), 1993, at 378–390.

12. Michael J. Grubb and Niels I. Meyer, *Wind Energy: Resources, Systems, and Regional Strategies*, in RENEWABLE ENERGY: SOURCES FOR FUELS AND ELECTRICITY, T.B. Johansson and L. Burnham, Eds. (Washington, DC: Island Press, 1993).

13. European Wind Energy Association, *Wind Force 12*, available at http://www.ewea.org.

14. G.A.M. van Kuik and J.G. Slootweg, *Wind Energy Harvest and Storage Strategies*, in VGB Conference Proceedings, Brussels, Belgium, 2001.

15. Suppose that a perfect lossless electricity storage technology was available. Such a storage system would make wind dispatchable but would not alter the average capacity factor of the wind power system. In this case, the cost of the wind plus free storage, C_W, would be equivalent to the generation cost of intermittent wind, which could approach 3 ¢/kWh in the near future with continued design improvements and cost reductions.

16. See Hirst and Hild, *supra* note 8.

17. Randy Hudson and Brendan Kirby, *The Impact of Wind Generation on System Regulation Requirements*, in Proceedings of Windpower 2001.

18. See Hirst, *supra* note 7.

19. See Hudson and Kirby, *supra* note 17.

20. Bernard Ernst, Analysis of Wind Power Ancillary Services Characteristics with German 250 MW Wind Data (Golden, Colorado: NREL, 1999).

21. Michael Milligan, *Wind Power Plants and System Operation in the Hourly Time Domain*, in Proceedings of the Windpower 2003 conference, AWEA, Austin, TX.

22. Statistical analysis of PJM and simulated wind power time series was based on data described in Joseph F. DeCarolis and David W. Keith, *The Economics of Large-Scale Wind Power in a Carbon Constrained World*, ENERGY POLICY, forthcoming. The hourly ramping requirements for PJM between 1997 and 2002 have a sub-Gaussian distribution: only 0.09 percent of the hours fall outside the 3σ risk level, substantially less than the 0.3 percent predicted by a Gaussian distribution. For comparison, the hourly differences in simulated wind power from five different wind sites exhibit a super-Gaussian distribution, i.e. roughly 2 percent of the hourly load-following requirements for each wind site fall outside the 3σ limit.

23. See Hirst and Hild, *supra* note 8.

24. Michael J. Grubb, The Economic Value of Wind Energy at High Power System Penetrations: An Analysis of Models, Sensitivities and Assumptions, WIND ENG'G 12(1), 1988, at 1–26.

25. DeCarolis and Keith, *supra* note 22.

26. *Id*.

27. For a detailed argument, see Joseph F. DeCarolis, *The Economics and Environmental Impacts of Large-Scale Wind Power in a Carbon Constrained World*, Ph.D. thesis (Pittsburgh: Carnegie Mellon University, 2004).

28. Steven Smith, personal communication, Apr. 20, 2004.

 1040-6190/$–see front matter © 2005 Elsevier Inc. All rights reserved., doi:/10.1016/j.tej.2004.12.006

Exhibit No. EDK-7

Xcel Energy and the Minnesota Department of Commerce Wind Integration Study - Final Report

September 28, 2004

EnerNex
CORPORATION

Xcel Energy and the Minnesota Department of Commerce

Wind Integration Study - Final Report

Prepared by

EnerNex Corporation
144-E Market Place Boulevard
Knoxville, Tennessee 37923
tel: (865) 691-5540
fax: (865) 691-5046
www.enernex.com

Wind Logics, Inc.
1217 Bandana Blvd. N.
St. Paul, MN, 55108
www.windlogics.com

September 28, 2004

Preface

In June of 2003 the Minnesota Legislature adopted a requirement for an Independent Study of Intermittent Resources, which evaluates the impacts of over 825 MW of wind power on the NSP system[1]. The Public Utilities Commission requested that the Department of Commerce take responsibility for oversight of the Study with the understanding that the Office of the Reliability Administrator would represent the Department[2].

After the conclusion of the 2003 Legislative session a thorough and complete research of the current status and understanding of integrating wind power into electric power systems, including a comprehensive literature search, was completed. A broad-based workgroup was assembled to guide the initial development of the Study. This group included representatives of Xcel Energy, Minnesota municipal utilities, Minnesota cooperative utilities, the Minnesota Chamber of Commerce, the American Wind Energy Association, Minnesota environmental organizations, the U.S Department of Energy / National Renewable Energy Laboratory, and the Department of Commerce.

Members of that workgroup included:

Jim Alders	Xcel Energy
Rory Artig	Minnesota Department of Commerce
Bill Blazar	Minnesota Chamber of Commerce
Laura Bordelon	Minnesota Chamber of Commerce
Jim Caldwell	American Wind Energy Association
Bob Cupit	Minnesota Department of Commerce
Chris Davis	Minnesota Department of Commerce
Bill Grant	Izaak Walton League of America
Clair Moeller	Xcel Energy
Michael Noble	ME3
Brian Parsons	National Renewable Energy Laboratory
Judy Poferl	Xcel Energy
Larry Schedin	Reliant Energy Integration Services
Matt Schuerger	Energy Systems Consulting Services
Craig Turner	Dakota Electric Association
Greg Woodworth	Rochester Public Utilities
Ken Wolf	Minnesota Department of Commerce

[1] Minnesota Laws 2003, 1st Special Session, Chapter 11, Article 2, Section 21.
[2] MN PUC Docket No. E-002/CI-03-870, Order Requiring Engineering Study

The workgroup met several times to develop the Statement of Work for the study. Xcel Energy competitively bid the study and contracted with the successful bidder, a team lead by EnerNex Corporation.

This study is a significant advance in the science and understanding of the impacts of the variability of wind power on power system operation in the Midwest. For example, the application of sophisticated, science-based atmospheric models to accurately characterize the variability of Midwest wind generation is a vast improvement over previous methods.

The study benefited from extensive expert guidance and review by a Technical Review Committee (TRC).

Thank you to all of the participants in the TRC, which included:

Jim Alders	Xcel Energy
Steve Beuning	Xcel Energy
Laura Bordelon	Minnesota Chamber of Commerce
Jim Caldwell	American Wind Energy Association/PPM Energy
Bob Cupit	Minnesota Department of Commerce
Ed DeMeo	Utility Wind Interest Group/ Renewable Energy Consulting Services, Inc.
John Donatell	Xcel Energy
David Duebner	Midwest Independent System Operator
Bill Grant	Izaak Walton League
Walt Grivna	Xcel Energy
Mark Haller	American Wind Energy Association/ Haller Wind Consulting
Rick Halet	Xcel Energy
Larry Hartman	Minnesota Environmental Quality Board
Mike Jacobs	American Wind Energy Association
Stephen Jones	Xcel Energy
Mark McGree	Xcel Energy
Mike McMullen	Xcel Energy
Michael Milligan	National Renewable Energy Laboratory
Michael Noble	Minnesotans for an Energy Efficient Economy
Dale Osborn	Midwest Independent System Operator
Brian Parsons	National Renewable Energy Laboratory
Lisa Peterson	Xcel Energy
Rick Peterson	Xcel Energy
Greg Pieper	Xcel Energy
Larry Schedin	Technical Advisor to the MN DOC

Matt Schuerger	Technical Advisor to the MN DOC
Steve Wilson	Xcel Energy
Ken Wolf	Minnesota Department of Commerce

The aggressive schedule for completion of this study prevented investigation of several critical next steps. The study outlines several important next steps needed to develop effective solutions to mitigate these impacts including improved strategies and practices for unit commitment and scheduling as well as improved forecasting and markets.

Ken Wolf

Reliability Administrator
Minnesota Department of Commerce

Project Team

EnerNex Corporation

Robert M. Zavadil – Project Manager

Jack King

Leo Xiadong

WindLogics

Mark Ahlstrom

Dr. Bruce Lee

Dr. Dennis Moon

Dr. Cathy Finley

Lee Alnes

Arreva T&D

Dr. Lawrence Jones

Fabrice Hudry

Mark Monstream

Stephen Lai

NexGen Energy LLC

J. Charles Smith

Contents

List of Tables

List of Figures

Project Summary

Introduction

In 2003, the Minnesota Legislature adopted a requirement for an Independent Study of Intermittent Resources to evaluate the impacts of over 825 MW of wind power on the Xcel Energy system. The Minnesota Public Utilities Commission requested that the office of the Reliability Administrator of the Minnesota Department of Commerce take responsibility for the study and its scope and administration. Through a competitive bidding process, the study was commissioned in January of 2004. Results of that study are reported here.

Xcel Energy, formed by the merger of Denver-based New Centuries Energies and Minneapolis-based Northern States Power Company, is the fourth-largest combination electricity and natural gas energy company in the United States. Xcel Energy serves over 1.4 million electric customers in the states of Minnesota, Wisconsin, North Dakota, South Dakota and Michigan. Their peak demand in this region is approximately 9,000 MW in 2003 and projected to rise to approximately 10,000 MW by 2010.

In 2003, the Xcel Energy operating area in Minnesota, Wisconsin, and parts of the Dakotas had about 470 MW of wind power under contract, including about 300 MW operating, in Southwestern Minnesota. An additional 450 MW of wind power has been awarded through the 2001 All Source Bid process. Minnesota legislation could result in a total of 1,450 to 1,750 MW of wind power serving the NSP system by 2010 and 1,950 to 2,250 MW by 2015.

An earlier study commissioned by Xcel Energy and the Utility Wind Interest Group (UWIG, www.uwig.org) estimated that the approximately 300 MW of wind generation in Xcel Energy's control area in Minnesota at that time resulted in additional annual costs to Xcel of $1.85 for each megawatt-hour (MWH) of wind energy delivered to the system. While for some time there had been recognition and consensus that the unique characteristics of wind generation likely would have some technical and financial impacts on the utility system, this study was the first attempt at a formal quantification for an actual utility control area.

The study looked at the "operating" time frame, which consists primarily of those activities required to ensure that there will be adequate electric energy supply to meet the projected demand over the coming hours and days, that the system is operated at all times so as not to compromise security or reliability, and that the demand be met at the lowest possible cost.

The study reported on here takes a similar perspective. The scenario evaluated, however, is dramatically different. Instead of 300 MW of wind generation confined to relatively small parts of two adjacent counties, a potential future development of 1500 MW of wind generation spread out over hundreds of square miles is considered. In addition, the wind generation central to the previous study was well characterized through existing monitoring projects and measurements at all of the time scales of interest, making questions about how wind generation would appear to the Xcel system operators relatively simple to address. In this study, developing a characterization of how large, geographically-diverse wind plants would appear in the aggregate to the system operators was one early and major challenge.

To better understand the study scope, its specific challenges, and the results, some background on utility system operations and the characteristics of wind generation is helpful.

Overview of Utility System Operations

Interconnected power systems are large and extremely complex machines, consisting of thousands of individual elements. The mechanisms responsible for their control must continually adjust the supply of electric energy to meet the combined and ever-changing electric demand of the system's users. There are a host of constraints and objectives that govern how this is done. For example, the system must operate with very high reliability and provide electric energy at the lowest possible cost. Limitations of individual network elements -generators, transmission lines, substations - must be honored at all times. The capabilities of each of these elements must be utilized in a fashion to provide the required high levels of performance and reliability at the lowest overall cost.

Operating the power system, then, involves much more than adjusting the combined output of the supply resources to meet the load. Maintaining reliability and acceptable performance, for example, requires that operators:

- Keep the voltage at each node (a point where two or more system elements - lines, transformers, loads, generators, etc. - connect) of the system within prescribed limits;
- Regulate the system frequency (the steady electrical speed at which all generators in the system are rotating) of the system to keep all generating units in synchronism;
- Maintain the system in a state where it is able to withstand and recover from unplanned failures or losses of major elements

The activities and functions necessary for maintaining system performance and reliability and minimizing costs are generally classified as "ancillary services." While there is no universal agreement on the number or specific definition of these services, the following items adequately encompass the range of technical aspects that must be considered for reliable operation of the system:

- Voltage regulation and VAR dispatch - deploying of devices capable of generating reactive power to manage voltages at all points in the network;
- Regulation - the process of maintaining system frequency by adjusting certain generating units in response to fast fluctuations in the total system load;
- Load following - moving generation up (in the morning) or down (late in the day) in response to the daily load patterns;
- Frequency-responding spinning reserve - maintaining an adequate supply of generating capacity (usually on-line, synchronized to the grid) that is able to quickly respond to the loss of a major transmission network element or another generating unit;
- Supplemental Reserve - managing an additional back-up supply of generating capacity that can be brought on line relatively quickly to serve load in case of the unplanned loss of significant operating generation or a major transmission element.

The frequency of the system and the voltages at each node are the fundamental performance indices for the system. High interconnected power system reliability is a consequence of maintaining the system in a secure state - a state where the loss of any element will not lead to cascading outages of other equipment - at all times.

The electric power system in the United States (contiguous 48 states) is comprised of three interconnected networks: the Eastern Interconnection (most of the states East of the Rocky Mountains), the Western Interconnection (Rocky Mountain States west to the Pacific Ocean), and ERCOT (most of Texas). Within the Eastern and Western interconnections, dozens of individual "control" areas coordinate their activities to maintain reliability and conduct transactions of electric energy with each other. A number of these individual control areas are members of Regional Transmission Organizations (RTOs), which oversee and coordinate activities across a number of control areas for the purposes of maintaining the security of the interconnected power system and implementing wholesale power markets.

A control area consists of generators, loads, and defined and monitored transmission ties to neighboring areas. Each control area must assist the larger interconnection with maintaining frequency at 60 Hz, and balance load, generation, out-of-area purchases and sales on a continuous basis. In addition, a prescribed amount of backup or reserve capacity (generation that is unused but available within a certain amount of time) must be maintained at all times as protection against unplanned failure or outage of equipment.

To accomplish the objectives of minimizing costs and ensuring system performance and reliability over the short term (hours to weeks), the activities that go on in each control area consist of:

- Developing plans and schedules for meeting the forecast load over the coming days, weeks, and possibly months, considering all technical constraints, contractual obligations, and financial objectives;
- Monitoring the operation of the control area in real time and making adjustments when the actual conditions - load levels, status of generating units, etc. - deviate from those that were forecast.

A number of tools and systems are employed to assist in these activities. Developing plans and schedules involves evaluating a very large number of possibilities for the deployment of the available generating resources. A major objective here is to utilize the supply resources so that all obligations are met and the total cost to serve the projected load is minimized. With a large number of individual generating units with many different operational characteristics and constraints, fuel types, efficiencies, and other supply options such as energy purchases from other control areas, software tools must be employed to develop optimal plans and schedules. These tools assist operators in making decisions to "commit" generating units for operation, since many units cannot realistically be stopped or started at will. They are also used to develop schedules for the next day or days that will result in minimum costs if adhered to and if the load forecasts are accurate.

The Energy Management System (EMS) is the technical core of modern control areas. It consists of hardware, software, communications, and telemetry to monitor the real-time performance of the control area and make adjustments to generating unit and other network components to achieve operating performance objectives. A number of these adjustments happen very quickly without the intervention of human operators. Others, however, are made in response to decisions by individuals charged with monitoring the performance of the system.

The nature of control area operations in real-time or in planning for the hours and days ahead is such that increased knowledge of what will happen correlates strongly to better strategies for managing the system. Much of this process is already based on predictions of uncertain quantities. Hour-by-hour forecasts of load for the next day or several days, for example, are critical inputs to the process of deploying electric generating units and scheduling their operation. While it is recognized that load forecasts for future periods can never be 100% accurate, they nonetheless are the foundation for all of the procedures and process for operating the power system. Increasingly sophisticated load forecasting techniques and decades of experience in applying this information have done much to lessen the effects of the inherent uncertainty

Characteristics of Wind Generation

The nature of its "fuel" supply distinguishes wind generation from more traditional means for producing electric energy. The electric power output of a wind turbine depends on the speed of the wind passing over its blades. The effective speed (since the wind speed across the swept area of the wind turbine rotor is not necessarily uniform) of this moving air stream exhibits variability on a wide range of time scales – from seconds to hours, days, and seasons. Terrain, topography, other nearby turbines, local and regional weather patterns, and seasonal and annual climate variations are just a few of the factors that can influence the electrical output variability of a wind turbine generator.

It should be noted that variability in output is not confined only to wind generation. Hydro plants, for example, depend on water storage that can vary from year to year or even seasonally. Generators that utilize natural gas as a fuel can be subject to supply disruptions or storage limitations. Cogeneration plants may vary their electric power production in response to demands for steam rather than the wishes of the power system operators. That said, the effects of the variable fuel supply are likely more significant for wind generation, if only because the experience with these plants accumulated thus far is so limited.

An individual turbine is negligibly small with respect to the load and other supply resources in the control area, so the aggregate performance of a large number of turbines is what is of primary interest with respect to impacts on the transmission grid and system operations. Large wind generation facilities that connect directly to the transmission grid employ large numbers of individual wind turbine generators, with the total nameplate generation on par with other more conventional plants. Individual wind turbine generators that comprise a wind plant are usually spread out over a significant geographical area. This has the effect of exposing each turbine to a slightly different fuel supply. This spatial diversity has the beneficial effect of "smoothing out" some of the variations in electrical output. The benefits of spatial diversity are also apparent on larger geographical scales, as the combined output of multiple wind plants will be less variable (as a percentage of total output) than for each plant individually.

Another aspect of wind generation, which applies to conventional generation but to a much smaller degree, is the ability to predict with reasonable confidence what the output level will be at some time in the future. Conventional plants, for example, cannot be counted on with 100% confidence to produce their rated output at some coming hour since mechanical failures or other circumstances may limit their output to a lower level or even result in the plant being taken out of service. The probability that this will occur, however, is low enough that such an occurrence is often discounted or completely ignored by power system operators in short-term planning activities.

Because wind generation is driven by the same physical phenomena that control the weather, the uncertainty associated with a prediction of generation level at some future hour, even maybe the next hour, is significant. In addition, the expected accuracy of any prediction will degrade as the time horizon is extended, such that a prediction for the next hour will almost always be more accurate than a prediction for the same hour tomorrow.

The combination of production variability and relatively high uncertainty of prediction makes it difficult, at present, to "fit" wind generation into established practices and methodologies for power system operations and short-term planning and scheduling. These practices, and even emerging concepts such as hour- and day-ahead competitive markets, have a necessary bias toward "capacity" - because of system security and reliability concerns so fundamental to power system operation - with energy a secondary consideration. Wind generation is a clean, increasingly inexpensive, and stable supply of electric energy. The challenge going forward is to better understand how wind energy as a supply resource interacts with other types of electric generation and how it can be exploited to maximize benefits, in spite its unique characteristics.

Wind Generation and Long-Term Power System Reliability

In longer term planning of electric power systems, overall reliability is often gauged in terms of the probability that the planned generation capacity will be insufficient to meet the projected system demand. This question is important from the planning perspective because it is recognized that even conventional electric generating plants and units are not completely reliable – there is some probability that in a given future hour capacity from the unit would be unavailable or limited in capability due to a forced outage – i.e. mechanical failure. This probability of not being able to meet the load demand exists even if the installed capacity in the control area exceeds the peak projected load.

In this sense, conventional generating units are similar to wind plants. For conventional units, the probability that the rated output would not be available is rather low, while for wind plants the probability could be quite high. Nevertheless, it is likely that a formal statistical computation of system reliability would reveal that the probability of not being able to meet peak load is lower with a wind plant on the system than without it.

The capacity value of wind plants for long term planning analyses is currently a topic of significant discussion in the wind and electric power industries. Characterizing the wind generation to appropriately reflect the historical statistical nature of the plant output on hourly, daily, and seasonal bases is one of the major challenges. Several techniques that capture this variability in a format appropriate for formal reliability modeling have been proposed and tested. The lack of adequate historical data for the wind plants under consideration is an obstacle for these methods.

The capacity value issue also arises in other, slightly different contexts. In the Mid-Continent Area Power Pool (MAPP), the emergence of large wind generation facilities over the past decade led to the adaptation of a procedure use for accrediting capacity of hydroelectric facilities for application to wind facilities. Capacity accreditation is a critical aspect of power pool reserve sharing agreements. The procedure uses historical performance data to identify the energy delivered by these facilities during defined peak periods important for system reliability. A similar retrospective method was used in California for computing the capacity payments to third-party generators under their Standard Offer 4 contract terms.

By any of these methods, it can be shown that wind generation does make a calculable contribution to system reliability in spite of the fact that it cannot be directly dispatched like most conventional generating resources. The magnitude of that contribution and the appropriate method for its determination remain important questions.

Objectives of this Study

The need for various services to interoperate with the interconnected electric power system is not unique to wind. Practically all elements of the bulk power network – generators, transmission lines, delivery points (substations) – have an influence on or increase the aggregate demand for ancillary services. Within the wind industry and for those transmission system operators who now have significant experience with large wind plants, the attention has turned from debating whether wind plants require such support but rather to the type and quantity of such services necessary for successful integration.

Many of the earlier concerns and issues related to the possible impacts of large wind generation facilities on the transmission grid have been shown to be exaggerated or unfounded by a growing body of research, studies, and empirical understanding gained from the installation and operation of over 6000 MW of wind generation in the United States.

The focus of these studies covers the range of technical questions related to interconnection and integration. With respect to the ancillary services listed earlier, there is a growing emphasis on better understanding how significant wind generation in a control area affects operations in the very short term – i.e. real-time and a few hours ahead – and planning activities for the next day or several days.

Recent studies, including the initial study for Xcel Energy by the UWIG, have endeavored to quantify the impact of wind generation facilities on real-time operation and short-term planning for various control areas. The methods employed and the characteristics of the power systems analyzed vary substantially. There are some common findings and themes throughout these studies, however, including:

- Despite differing methodologies and levels of detail, ancillary service costs resulting from integrating wind generation facilities are relatively modest for the growth in U.S. wind generation expected over the next three to five years.
- The cost to the operator of the control area to integrate a wind generation facility is obviously non-zero, and increases as the ratio of wind generation to conventional supply sources or the peak load in the control area increases.
- For the penetration levels (ratio of nameplate wind generation to peak system load) considered in these studies (generally less than 20%) the integration costs per MWH of wind energy were likely modest.
- Wind generation is variable and uncertain, but how this variation and uncertainty combines with other uncertainties inherent in power system operation (e.g. variations in load and load forecast uncertainty) is a critical factor in determining integration costs.
- The effect of spatial and temporal diversity with large numbers of individual wind turbines is a key factor in smoothing the output of wind plants and reducing their ancillary service requirements from a system-wide perspective.

The objective of this study is to conduct a comprehensive, quantitative assessment of integration costs and reliability impacts of 1500 MW of wind generation in the Xcel Energy control area in Minnesota in the year 2010, when the peak load is projected to be just under 10,000 MW. As discussed previously, such a large wind generation scenario poses some significant study challenges, and lies near the outer edge penetration-wise of the studies conducted to date.

Per the instructions developed by Xcel Energy and the Minnesota Department of Commerce, the study was to focus on those issues, activities, and functions related to the short-term planning and scheduling of electric generation resources and the operation of the Xcel control area in real time, and questions concerning the contributions of wind generation to power system reliability. While very important for wind generation and certainly a topic of much current discussion in the upper Midwest, ***transmission issues were not to be addressed in this study***. Some transmission issues are considered implicitly, as interactions with neighboring control areas and the emerging wholesale power markets being administered by MISO (Midwest Independent System Operator) are relevant to the questions addressed here.

Organization of Documentation

The report for this study is provided as two volumes. This volume of the report addresses each of the four tasks of the report and provides the final conclusions. A second, stand-alone volume contains all of the detail for the first task of the study, a complete characterization of the wind resource in Minnesota. In it are dozens of color maps and charts that describe and quantify the meteorology that drives the wind resource in the upper Midwest, along with graphical depictions of the locational variation of the wind resource and potential wind generation by month and time of day. Some of the material from this companion volume is repeated as it describes the process for developing the wind generation model that used for the later tasks.

The major sections of this document address each of four tasks as defined in the work scope of the original request-for-proposal (RFP).

Task 1: Characterizing the Nature of Wind Power Variability in the Midwest - Overview and Results

A major impediment to obtaining a better understanding of how large amounts of wind generation would affect electric utility control area operations and wholesale power markets is the relative lack of historical data and operating experience with multiple, geographically dispersed wind plants.

Measurement data and other information have been compiled over the past few years on some large wind plants across the country. The Lake Benton plants at the Buffalo Ridge substation in southwestern Minnesota have been monitored in detail for several years. The understanding of how a single large wind plant might behave is much better today than it was five years ago.

For the study, predicting how all of the wind plants in the 1500 MW scenario appear in the aggregate to the Xcel system operators and planners is a critical aspect. That total amount of wind generation will likely consist of many small and large facilities spread out over a large land area, with individual facilities separated by tens of miles up to over two hundred miles.

The approach for this study was to utilize sophisticated meteorological simulations and archived weather data to "recreate" the weather for selected past years, with "magnification" in both space and time for the sites of interest. Wind speed histories from the model output for the sites at heights for modern wind turbines were then converted to wind generation histories.

Figure 1 shows the "grid" used with the MM5 numerical model to simulate the actual meteorology occurring over the upper Midwest. The simulation featured two internal, nested grids of successively higher spatial resolution. On the innermost grid, specific points that were either co-located with existing wind plants or likely prospects for future development were identified. Wind speed data along with other key atmospheric variables from these selected grids (Figure 2) were saved at ten-minute intervals as the simulation progressed through three years of weather modeling.

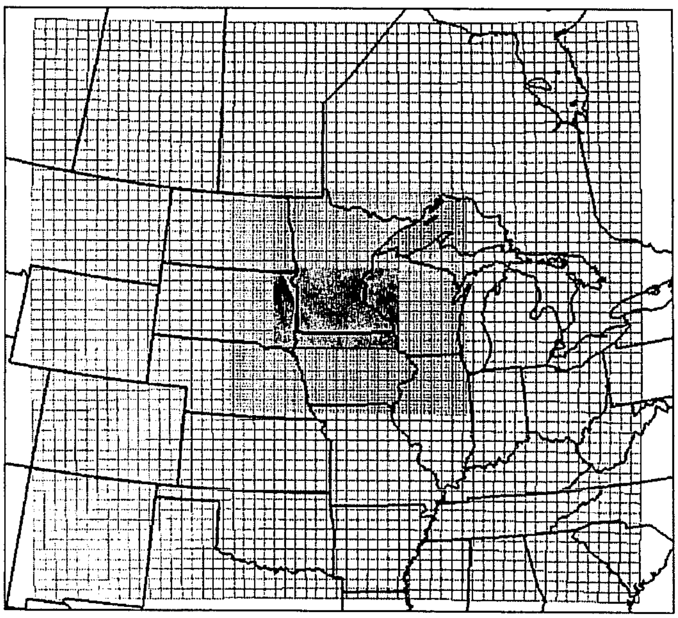


Figure 1: MM5 nested grid configuration utilized for study area. The 3 grid run includes 2 inner nested grids to optimize the simulation resolution in the area of greatest interest. The grid spacing is 45, 15 and 5 km for the outer, middle and innermost nests, respectively.

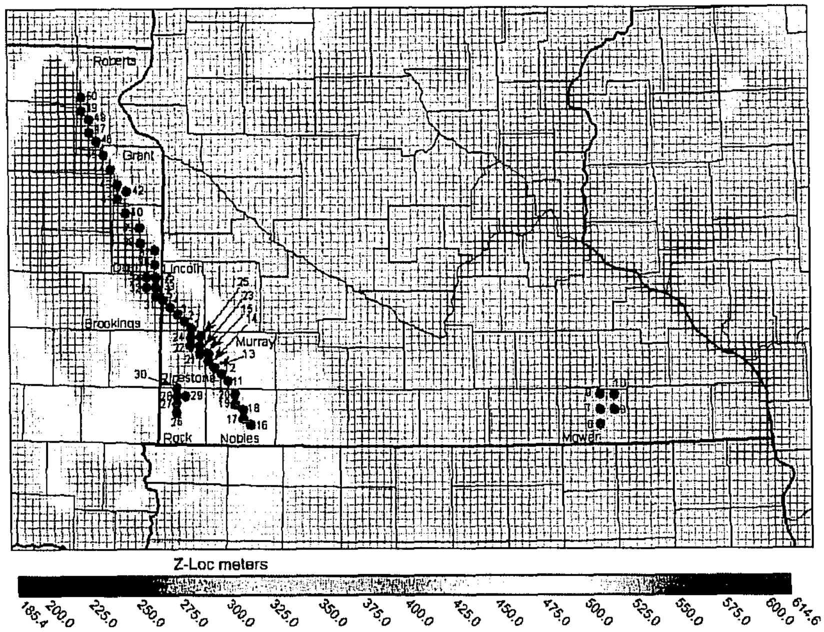


Figure 2: "Tower" locations on the innermost MM5 model grid where wind speed data and other meteorological data were captured and archived at ten-minute intervals.

The high-resolution time series of wind speed data was converted to wind generation data by applying power curves for existing and prospective commercial wind turbines at each of the grid points. As a check on the accuracy of this overall modeling approach, the calculated wind generation data was compared to actual measurements from groups of turbines in the Lake Benton, MN area for the entire year of 2003 to validate the models. A comparison for a typical month is shown in Figure 3.

5.87	ME as % of Cap
14.8	MAE as % of Cap
0.81	Correlation

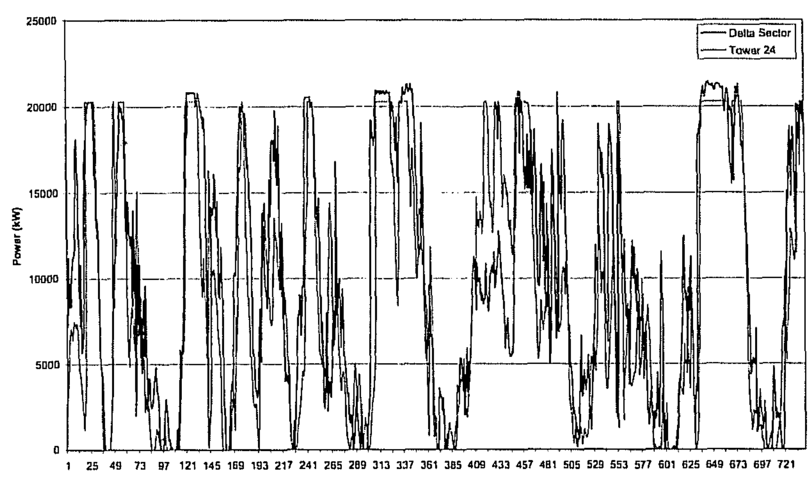


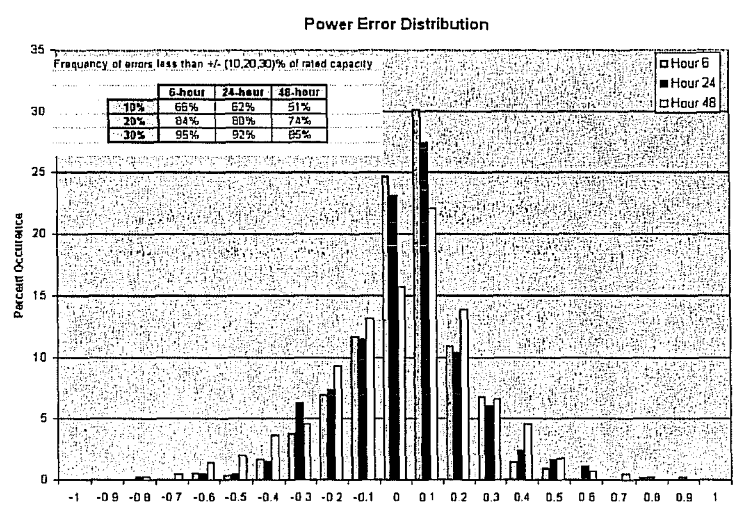
Figure 3: Comparison of simulated wind generation data to actual measurements for a group of wind turbines at Lake Benton, MN on the Buffalo Ridge

The validation exercise showed that the numerical weather modeling approach produced high quality results. In months where the wind is driven by larger-scale weather patterns, the average error as a percentage of power production over the period was about 6%. In the summer months, where smaller-scale features such as thunderstorm complexes have more influence on wind speed, the mean error was larger, but still less than 9%. Mean absolute errors as a percent of capacity were approximately 15% or less for most months.

A critical feature of the wind generation model for this study is that it captures the effects of the geographic dispersion of the wind generation facilities. For Xcel system operators, how the wind plants operate in the aggregate is of primary importance. This science-based modeling approach provides for representing the relationships between the behaviors of the individual plants over time more accurately than any other method.

Numerical weather simulations were also used in this task to develop a detailed characterization of the wind resource in Minnesota. Temporal and geographic variations in wind speed and power production over the southern half of Minnesota are characterized through a number of charts, graphs, and maps.

Task 1 concluded with a discussion of issues related to wind generation forecasting accuracy and a numerical experiment to compare various methods using the data and information compiled for developing the wind generation model. The accuracy of any weather-related forecast will decrease as the forecast horizon increases. Forecasts for the next few hours are likely to be significantly more accurate than those for the next few days. The forecast experiment did show, however, that a more sophisticated method employing artificial intelligence techniques, a computational learning system (CLS) in conjunction with a numerical weather model, holds promise for significantly improving the accuracy of forecasts spanning a range from a few hours ahead through a two day period. This forecasting technique likely will have value for control area operators. Such techniques are in the development stages now, but will be commercially available in the coming years, and relevant to the study year for which this project is being conducted.



	6-hour	24-hour	48-hour
10%	66%	62%	51%
20%	84%	80%	74%
30%	95%	92%	85%

Figure 4: Frequency distribution of power error as a percent of rated capacity for 6, 24 and 48 hour forecasts. Inset table shows the frequency of power errors less than 10, 20 and 30 percent of rated capacity for the CLS 6, 24 and 48 hour forecasts.

Since transmission constraints were not considered explicitly in this project, geographic variations in wind plant output are included in the analyses only to the extent that they affect the aggregated output profile of the total wind generation in the control area. However, the spatial variations could be combined with transmission constraints for a more refined evaluation, should that be desired in a future study.

Task 2: Develop Xcel Energy System Model for 2010 Study Year - Overview and Results

To conduct the technical analysis, models for both the wind generation development in Minnesota and the Xcel system in 2010 were developed. The wind generation scenario was derived from the numerical weather model data discussed in the previous section. In coordination with Xcel Energy and the Minnesota Department of Commerce, a county-by-county development scenario was constructed (Table 1) for the year 2010. The wind speed data created by the numerical weather model was converted to wind generation data at ten minute intervals for the three years of the simulation.

Table 1: Minnesota Wind Generation Development Scenario – CY2010

County	Nameplate Capacity
Lincoln	350 MW
Pipestone	250 MW
Nobles	250 MW
Murray	150 MW
Rock	50 MW
Mower	150 MW
Brookings (SD)	100 MW
Deuel (SD)	100 MW
Grant (SD)	50 MW
Roberts (SD)	50 MW
Total	**1,500 MW**

Xcel Energy predicts that the peak demand for their Minnesota control area will grow to 9933 MW in 2010. The projected resources to meet this demand are shown by type in Table 2 and graphically in Figure 5. Wind energy, which includes most of the wind generation assumed for this study, is assigned a capacity factor of 13.5% for purposes of this load and resources projection. Total capacity is projected to exceed peak demand by 15%.

Table 2: Xcel Capacity Resources for 2010

Resource Type	Capacity (MW)
Existing NSP-owned generation	7,529
Planned NSP-owned generation	773
Long-term firm capacity purchases	903
Other purchase contracts with third-party generators (including wind)	915
Short-term purchases considered as firm resources	1,307
Total	11,426

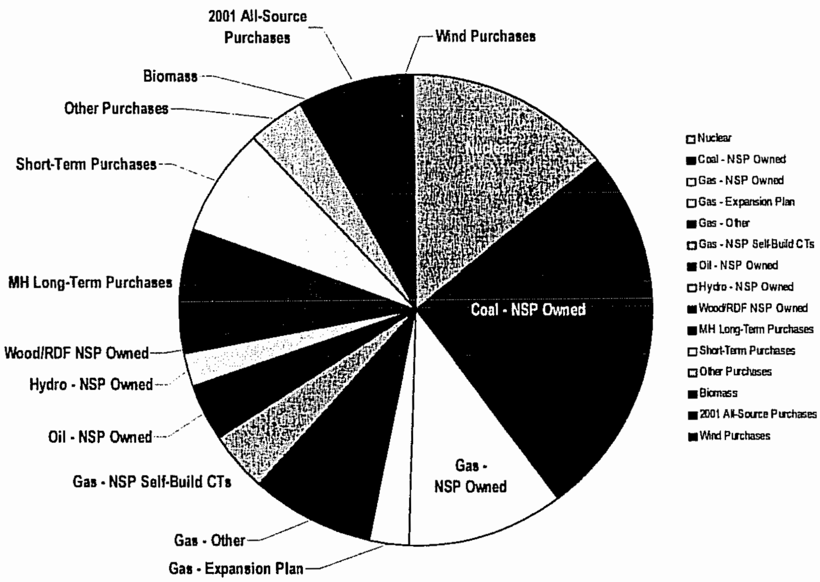


Figure 5: Xcel supply resources for 2010 by type and fuel.

Since transmission issues were not to be explicitly considered in this study, the remaining component of the Xcel system "model" for the study year is the system load. To conduct the technical analyses as specified in the RFP, it was necessary to characterize and analytically quantify the system load in great detail. A variety of measurements of the existing load were collected. To represent the system load in 2010, measurements of the current load (e.g. Figure 6) were scaled so that the peak hour for the year matched the expected peak in 2010 of 9933 MW.

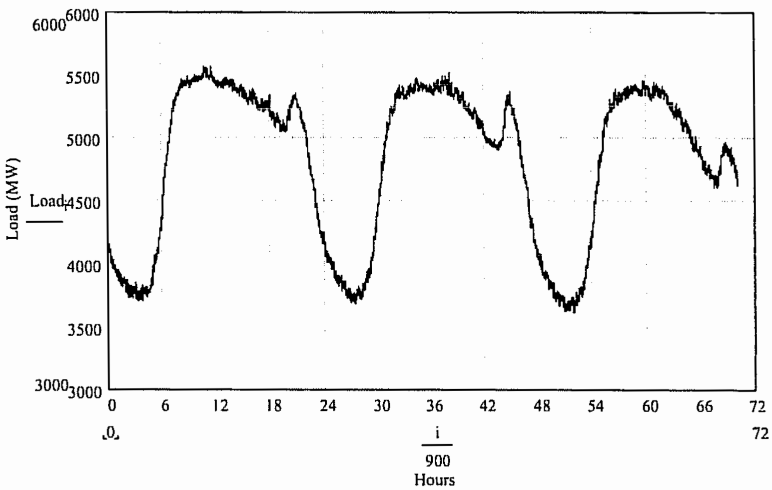


Figure 6: Measurements of existing load data used for characterizing expected load in 2010. Graph shows 72 hours of data collected at 4 second intervals by the Xcel Energy Management System (EMS)

The wind generation model derived from the numerical weather simulations was augmented with measurements from operating wind plants in Minnesota. The National Renewable Energy Laboratory (NREL) has been collecting very high resolution data from the Lake Benton I & II wind plants and the Buffalo Ridge substation in southwestern Minnesota for over three years. This data (Figure 7) was used to develop a representation of what the fastest fluctuations in wind energy delivery might look like to the Xcel system operators.

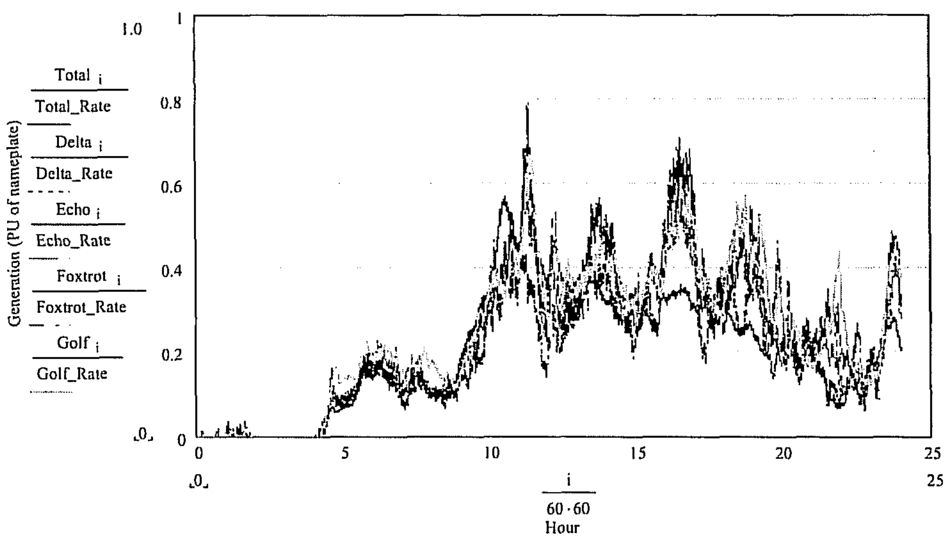


Figure 7: NREL high-resolution measurement data from Lake Benton wind plants and Buffalo Ridge substation. Data show is power production sampled at one second intervals.

Task 3: Evaluation of Wind Generation Reliability Impacts - Overview and Results

The purpose of the reliably analysis task of this study is to determine the ELCC (Effective Load Carrying Capability) of the proposed wind generation on the Xcel system. This problem was approached by modeling the system in the GE MARS (Multi-Area Reliability Simulation) program, simulating the system with and without the additional wind generation and noting the power delivery levels for the systems at a fixed reliability level. That reliability level is LOLE (Loss of Load Expectation) of 0.1 days per year.

The MARS program uses a sequential Monte Carlo simulation to calculate the reliability indices for a multi-area system by performing an hour by hour simulation. The program calculates generation and load for each hour of the study year, calculating reliability statistics as it goes. The year is simulated with different random forced outages on generation and transmission interfaces until the simulation converges.

In this study three areas are modeled, the Xcel system including all non-wind resources, an area representing Manitoba Hydro purchases and finally an area representing the Xcel Energy wind resources. The wind resources were separated to allow monitoring of hourly generation of the wind plant during the simulations.

The MARS model was developed based upon the 2010 Load and Resources table provided by Xcel Energy. In addition, load shape information was based upon 2001 actual hourly load data provided and then scaled to the 2010 adjusted peak load of 9933 MW.

The GE MARS input data file for the MAPP Reserve Capacity Obligation Review study was provided by MAPPCOR to assist in setting up the MARS data file for this study. State transition tables representing forced outage rate information and planned outage rate information for the Xcel resources where extracted from the file where possible. In some cases it was difficult to map resources from the MAPP MARS file to the Load/Resources table provided by Xcel Energy. In those cases the resource was modeled using a generic forced outage rate for the appropriate type of generation (steam, combustion turbine, etc) obtained from the MAPP data file.

The model used multiple levels of wind output and probabilities, based on the multiple block capacities and outage rates that can be specified for thermal resources in MARS. In each Monte Carlo simulation, the MARS program randomly selects the transition states that are used for the simulation. These states can change on and hour by hour basis, making MARS suitable for the modeling of the wind resources.

To find a suitable transition rate matrix, 3 years of wind generation data supplied by WindLogics was analyzed. That data was mapped on the proposed system and an hour by hour estimate of generation was calculated for the three years. The generation was analyzed and state transitions were calculated to form the state transition matrix for input to MARS.

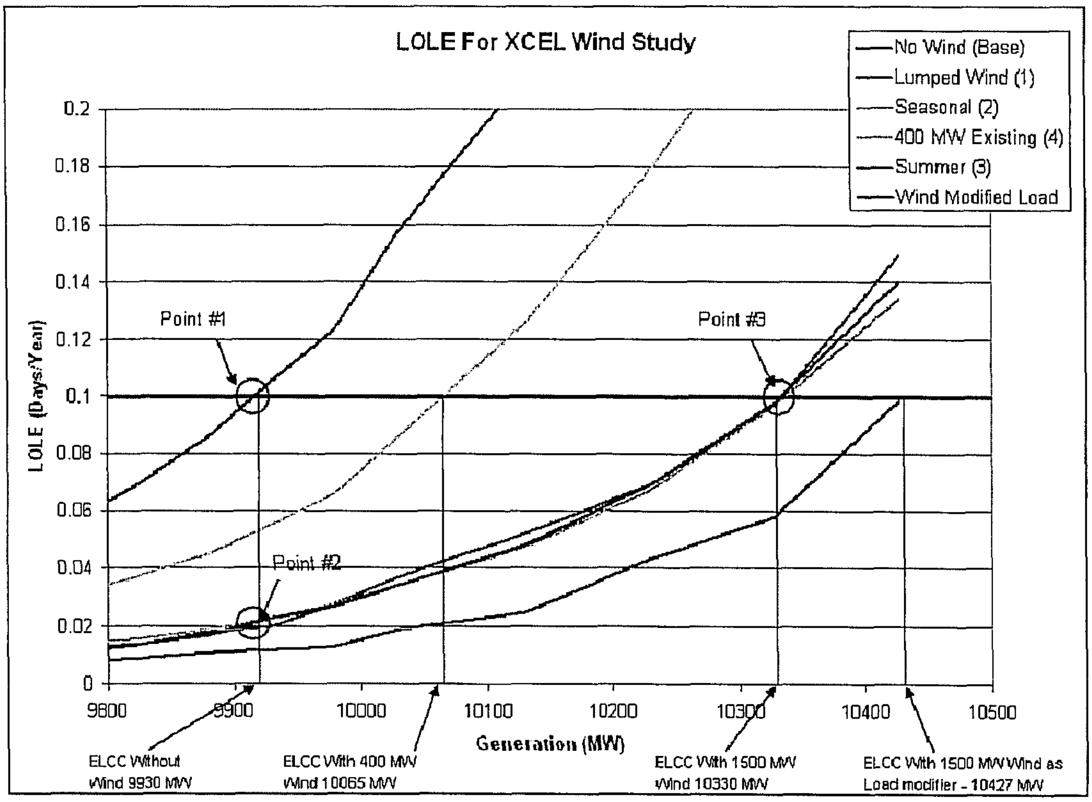


Figure 8: Results of reliability analysis for various wind generation modeling assumptions.

This result shows that the ELCC of the system improves by 400 MW or 26.67% of nameplate with the addition of 1500 MW of wind resource. The existing 400 MW improved the ELCC by 135 MW or about 33.75%. This is an estimate as the nameplate of the existing wind resource was not known precisely.

The results fall into the range of what would be "expected" by researchers and other familiar with modeling wind in utility reliability models. A remaining question, then, is one of the differences between the formal reliability calculation and the capacity accreditation procedure currently used in MAPP and being contemplated by other organizations.

The MAPP procedure takes the narrowest view of the historical production data by limiting it to only those hours around the peak hour for the entire month, which potentially excludes some hours where the load is still substantial and there would be a higher risk of outage. Applying the MAPP procedure to the aggregate wind generation model developed for this study yields a minimum capacity factor of about 17%. It is still smaller, however, than the ELCC computed using lumped or seasonal wind models (26.7%).

Even though the formal reliability calculation using GE-MARS utilizes a very large number of "trials" (replications) in determining the ELCC for wind generation, the wind model in each of those trials is still based on probabilities and state transition matrices derived from just three years of data. Some part of the difference between the MAPP method and the formal reliability calculation, therefore, can be attributed to an insufficient data set for characterizing the wind generation. When the sample of historical data is augmented to the ten year historical record prescribed in the MAPP method, the capacity value determined by the MAPP method would likely increase, reducing the magnitude of the difference between the two results.

This does not account for the entire difference between the methods, though. The MAPP procedure only considers the monthly peak hour, so the seasonal and diurnal wind generation variations as characterized in Task 1 of this project would lead to a discounting of its capacity value.

Table 3: Computed capacity values for 1500 MW wind generation scenario using MAPP accreditation procedure

Month	Median (MW)	%
January	394	26.3%
February	498	33.2%
March	285	19.0%
April	370	24.7%
May	423	28.2%
June	334	22.3%
July	249	16.6%
August	293	19.5%
September	492	32.8%
October	376	25.1%
November	499	33.3%
December	444	29.6%
AVERAGE	388	25.9%

There are clear differences between the MAPP Capacity Credit method and the ELCC approach used in this study. The MAPP algorithm selects wind generation data from a 4-hour window that includes the peak, and is applied on a monthly basis. The ELCC approach is a risk-based method that quantifies the system risk of meeting peak load, and is primarily applied on an annual basis. ELCC effectively weights peak hours more than off-peak hours, so that two hypothetical wind plants with the same capacity factor during peak hours can receive different capacity ratings. In a case like this, the plant that delivers more output during high risk periods would receive a higher capacity rating than a plant that delivers less output during high risk periods.

The MAPP approach shares a fundamental weakness with the method adopted by PJM: the 4-hour window may miss load-hours that have significant risk, therefore ignoring an important potential contribution from an intermittent generator. Conversely, an intermittent generator may receive a capacity value that is unjustifiably high because its generation in a high-risk hour is lower than during the 4-hour window.

Because ELCC is a relatively complex, data-intensive calculation, simplified methods could be developed at several alternative levels of detail. Any of these approaches would fully capture the system's high-risk hours, improving the algorithm beyond what would be capable with the fixed, narrow window in the current MAPP method. Any of the methods can also be applied to several years of data, which could be made consistent with current MAPP practice of using up to 10 years of data, if available.

Task 4: Evaluation of Wind Generation Integration Costs on the Operating Time Frame - Overview and Results

At significant levels relative to loads and other generating resources in the control area, wind generation has the potential to increase the burden of managing the power system, thereby increasing overall costs. The economic consequences of this increased burden are term "integration costs", and are the ultimate focus of this research effort. Integration costs for wind generation stem from two primary factors:

- Wind generation exhibits significant and mostly uncontrollable variability on all of the time scales relevant to power system operations - seconds, minutes, hours, days;
- The ability to predict or forecast wind generation for forward time periods is lower than that for conventional resources, and declines as the forecast horizon moves outward.

How the combination of these characteristics can impact the overall cost of operating the system can be thought of in the following way: For a given control area, the uncertainties associated with scheduling and operating generating resources, namely errors in load forecasts or unexpected outages or operating limitations of certain generating units - are well known based on history and experience. Procedures have evolved to accommodate these uncertainties, such that for a particular load magnitude or pattern, the supply resources are deployed and operated in a manner that minimizes the total production cost. The additional variability that comes with a significant amount of wind generation in the control area requires that the existing supply resources be used in a different manner. Increased uncertainty related to the probable errors in wind generation forecasts for future periods can lead to either more conservatism in the deployment of generating resources (and more cost) or operating problems that arise due to the differences between the forecast and actual wind generation in a particular hour (again, with possibly added cost).

The "value" of wind generation is separate from the integration costs. The objective here is to determine how the cost to serve load that is not served by wind generation is affected by the plans and procedures necessary to accommodate the wind generation and maintain the reliability and security of the power system.

In this project, the integration costs are differentiated by the time scale over which they might be incurred, with the total integration cost being the sum of the individual components. The time frames and operating functions of interest include:

- **Regulation**, which occurs on a very short time scale and involves the automatic control of a sufficient amount of generating capacity to support frequency and maintain scheduled transactions with other control areas;
- **Unit commitment and scheduling**, which are operations planning activities aimed at developing the lowest cost plan for meeting the forecast control area demand for the next day or days;

- **Load following and other intra-hourly operations** that involve the deployment of generating resources to track the demand pattern over the course of the day, and adjustments to compensate for changes in the control area demand as the load transitions through the hours and periods of the daily load pattern.

A variety of analytical techniques were employed to quantify the impacts of 1500 MW of wind generation on the Xcel control area. The following sections describe the methods used in each of the three time frames along with the results and conclusions.

Regulation

The aggregate load in the control area is constantly changing. The fastest of these changes can be thought of as temporary ups and downs about some longer term pattern. Compensating in some way for these fast fluctuations is necessary to meet control area performance standards and contribute to the frequency support for the entire interconnection. Regulation is that generating capacity that is deployed to compensate for these fast changes.

The regulation requirement for the Xcel system load in 2010 was projected by analyzing high-resolution measurements of the current load. By applying appropriate smoothing techniques, the fluctuating component responsible for the regulating burden can be isolated. Figure 9 shows the result of this algorithm for one hour of the Xcel load. The blue line is actual instantaneous load, sampled once every four seconds; the red line is the computed trend through the hour. The difference between the actual load and the trend is the regulating characteristic.

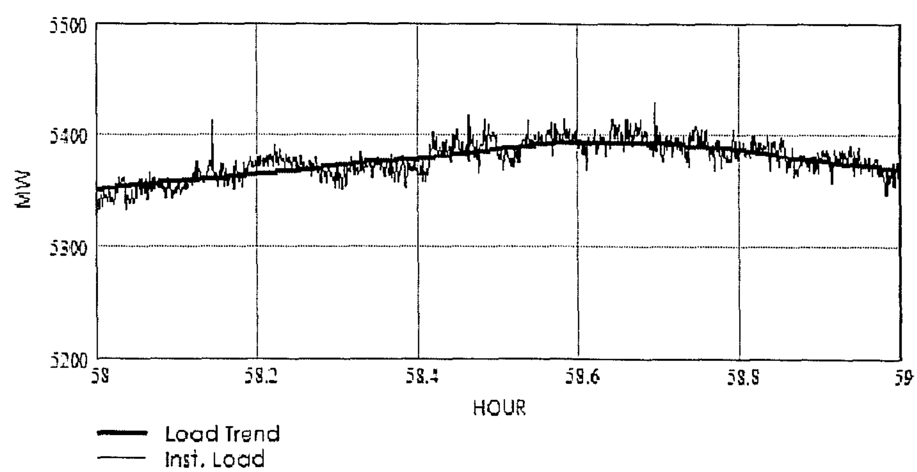


Figure 9: Actual load (blue) and hourly trend (red) for one hour.

Wind generation also exhibits fluctuations on this time scale, and thereby may increase the requirement for regulating capacity. The regulation trends are nearly energy neutral (the incremental energy for the time spent above the trend is equal to that spent below the trend), so the economic impact is the opportunity cost related to reserving the necessary amount of generation capacity to perform this function.

Data from NREL monitoring at the Lake Benton wind plants and the Buffalo Ridge substation was used to estimate the regulation requirements for the 1500 MW of wind generation in this study. Figure 10 contains a short sample of this data, which is collected at one second intervals. The graph shows actual wind generation(in percent of rated capacity) over a 24-hour period for several different collections of wind turbines, each of which is connected to the Buffalo Ridge substation.

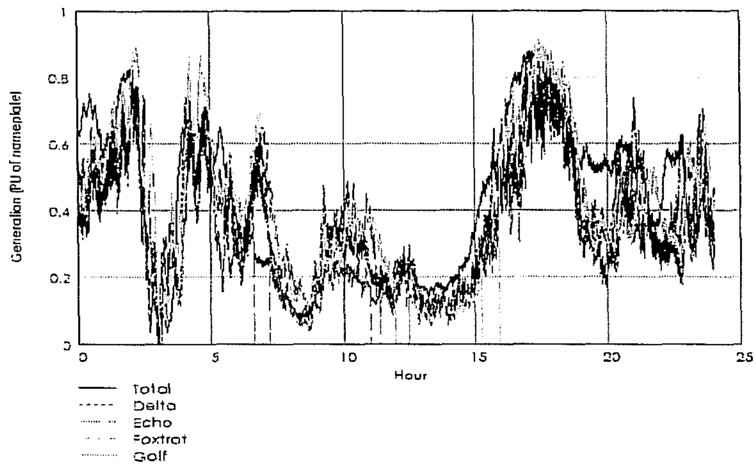


Figure 10: Typical daily wind generation for Buffalo Ridge plants data sampled at one second intervals for 24 hours.

The significant item to note from the figure is that the red trace corresponds to a measurement of 280 individual turbines. The other traces area from subsets of this overall number. Analysis of the data clearly shows that the fast fluctuations, when expressed as a percentage of the rated capacity of the turbines comprising the group, declines substantially as the number of turbines increases.

Because of the factors responsible for these fast fluctuations, it can be reasonably concluded that variations from one group of turbines are not dependent on or related to those from a geographically separated group. In statistical terms, the variations are uncorrelated.

It is further assumed that the fast fluctuations from a group or groups of wind turbines are not related to the fast fluctuations in the system load, since there is no plausible explanation for why they would be related. Of interest here is how the fluctuations of the system load with wind generation added compare to those from the system load alone.

For uncorrelated variations, statistics provides a straight-forward way to estimate the characteristics of the system load and wind combination. For normally-distributed random variables, the standard deviation of the combination can be computed from the standard deviations of the individual variables with the following formula:

$$\sigma_T = \sqrt{\sum \sigma_i^{\,2}}$$

The standard deviation of the combination of the variables is the square root of the sum of the squares of the individual standard deviations.

This statistical property can be applied to the random variables representing the fast fluctuations in wind generation and the load. In the study scenario, it was assumed that the 1500 MW of wind generation was actually comprised of 50 individual 30 MW wind plants. The regulation requirement for each of these plants was estimated to be 5% of the nameplate rating, based on the analysis of the measurement data from Buffalo Ridge. The standard deviation of the load fluctuations alone was calculated to be 20.2 MW for 2010. Applying the formula from above, the standard deviation of the Xcel system load in 2010 plus 1500 MW of wind generation is 22.8 MW.

A translation to regulating requirements can be made by recognizing that for the random, normally-distributed variables, over 99% of all of the variations will fall within plus or minus three standard deviations. So multiplying the results above by three leads to the conclusion that the addition of wind would increase the regulation requirement by (22.8 - 20.2) x 3 = 7.8 MW.

The "cost" of this incremental regulating requirement can be estimated by calculating the opportunity cost (revenue less production cost for energy that cannot be sold from the regulating capacity) for 7.8 MW of generating capacity. Xcel currently employs large fossil units for regulation, so the production cost is relatively low, around $10/MWH. If it is assumed that this energy could be sold at $25/MWH, the opportunity cost over the entire year would be just over $1,000,000.

Dividing the total cost by the expected annual energy production of the 1500 MW of wind generation (using an average capacity factor of 35%) yields an incremental regulation cost of $0.23/MWH.

Capacity value provides an alternative method for costing the incremental regulation requirement. Using a value of $10/kW-month or $120/kw-year, the annual cost of allocating an additional 7.8 MW of capacity to regulation duty comes out to be $936,000, about the same as the number arrived at through the simple opportunity cost calculation. This number and the previous result are not additive, however. By either method, the cost to Xcel for providing the incremental regulation capacity due to the 1500 MW of wind generation in the control area is about $1 million per year.

Unit Commitment and Scheduling - Hourly Impacts

Because many generating units cannot be stopped and started at will, forward-looking operating plans must be developed to look at the expected demand over the coming days and commit generation to meet this demand. This plan should result in the lowest projected production cost, but must also acknowledge the limitations and operating restrictions of the generating resources, provide for the appropriate amount of reserve capacity, and consider firm and opportunity sales and purchases of energy.

The approach for quantifying the costs that could be incurred with a significant amount of wind generation was based on mimicking the activities of the system schedulers, then calculating the costs of the resulting plans. The input data for the analysis consisted of hourly load data, wind generation data, and wind generation forecast data for a two year period. Figure 11 contains a block diagram of the process. For each day of the two year data set, a reference case was developed that assumed that the daily energy from wind generation was known precisely, and that it was delivered in equal amounts over the 24 hours of the day. This reference case was selected since it represents wind as a resource that would have the minimum impact on the operation of other supply resources.

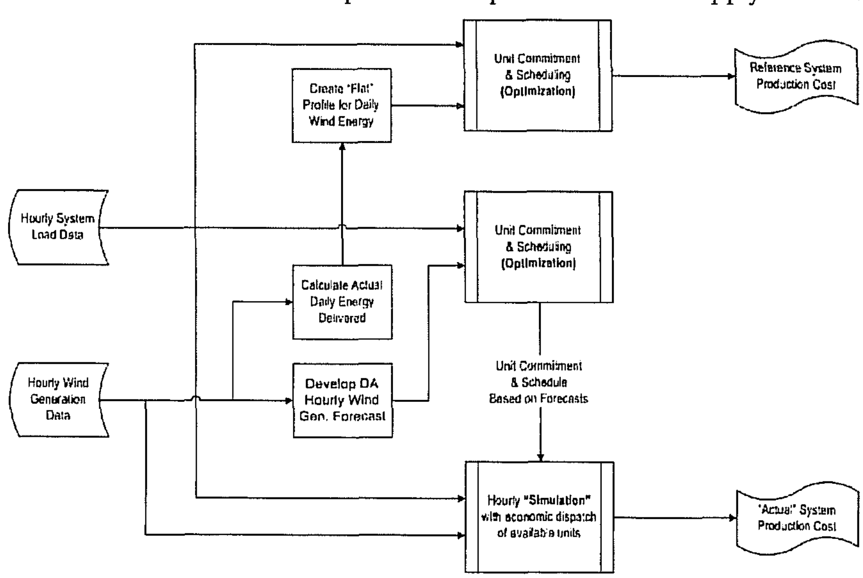


Figure 11: Block diagram of methodology used for hourly analysis.

The next set of cases represented the actions of the system schedulers. The projected load and an hour-by-hour wind generation forecast were input to the unit commitment and scheduling program. The program then determined the lowest cost way to meet the load and accommodate the wind generation as it was forecast to be delivered. The forecast wind generation was then replaced by "actual" wind generation. Then, a simulation of the same day was conducted. However, instead of allowing the program to change the planned deployment of generating resources, only the resources available per the plan developed with the wind generation forecast data could be used to meet the actual load, minus, of course, that load served by wind generation on an hourly basis.

This method was applied to 730 individual days that represented actual loads from 2002 and 2003 (scaled so that the peak matches that for 2010). Wind generation data from the numerical simulation model for each of the days over those two years represented "actual" wind generation. Using results from the forecasting experiment of Task 1, an additional time series was created to represent wind generation forecast data for those years (a comparison of forecast vs. actual as used in this study is shown in Figure 12). This set contained errors that are consistent with what would be expected from a wind generation forecast developed on the morning of the previous day (a time horizon of 16 to 40 hours).

Table 4 shows the results by month for the hourly analysis. The average hourly integration cost based on simulation of the commitment and scheduling process for 24 months is calculated to be $4.37/MWH of wind energy. The assumptions used in the hourly analysis make that cost a relatively conservative estimate – they are on the higher end of the range of results that could be generated by varying the assumptions. There appear to be a number of opportunities and mechanisms that would reduce those costs. The more important of these are related to the emergence of liquid wholesale markets administered by MISO which would provide an alternative to using internal resources to compensate for the variability of wind generation. Another is the analysis and development of algorithms for unit commitment and scheduling that explicitly account for the uncertainty in wind generation forecasts and lead to operating strategies that "win" more than they "lose" over the longer term. Closely related to such algorithms are further developments of wind generation forecasting techniques and analyses that would provide the appropriate input data.

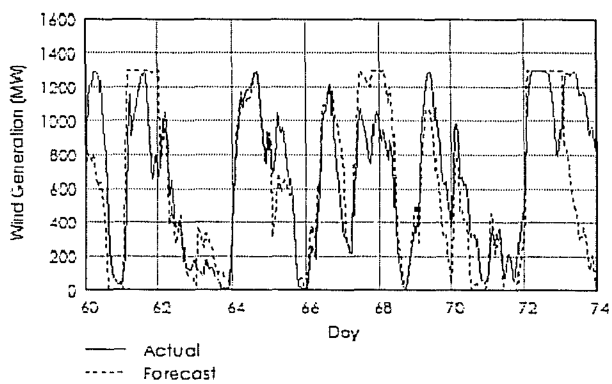


Figure 12: Wind generation forecast vs. actual for a two week period.

Table 4: Hourly Integration Cost summary

	Wind Generation (MWH)	Net Load Served (MWH)	Incr. Prod. Cost (k$)	HA Energy Cost (k$)	Hourly Integration Cost (per MWH)	Load served by Wind (of Total)
January	465,448	3,765,189	1,949	0	4.19	11.0%
February	472,998	3,295,060	1,560	313	3.96	12.6%
March	491,883	3,417,066	1,104	94	2.43	12.6%
April	485,379	3,139,152	2,564	118	5.52	13.4%
May	400,220	3,294,088	916	240	2.89	10.8%
June	316,798	3,699,027	930	226	3.65	7.9%
July	427,006	4,246,909	3,228	144	7.90	9.1%
August	301,811	4,546,729	2,992	332	11.01	6.2%
September	516,199	3,434,343	1,151	539	3.27	13.1%
October	478,654	3,382,287	1,607	63	3.49	12.4%
November	602,016	3,180,262	1,499	149	2.74	15.9%
December	625,926	3,508,015	4,186	0	6.69	15.1%
January	532,870	3,476,721	2,003	8	3.77	13.3%
February	581,258	2,917,429	1,431	139	2.70	16.6%
March	511,552	3,416,137	1,618	89	3.34	13.0%
April	501,014	3,122,346	1,579	85	3.32	13.8%
May	465,686	3,240,090	604	160	1.64	12.6%
June	509,564	3,824,551	198	749	1.86	11.8%
July	411,140	4,574,548	4,416	426	11.78	8.2%
August	430,083	3,982,906	1,732	276	4.67	9.7%
September	485,658	3,569,729	2,260	162	4.99	12.0%
October	395,261	3,447,750	1,997	362	5.97	10.3%
November	435,350	3,295,648	1,309	76	3.18	11.7%
December	507,473	3,494,610	1,699	299	3.94	12.7%
Totals	**11,351,247**	**85,270,590**	**44,531**	**5,048**	**4.37**	**11.7%**

Load Following and Intra-hourly Effects

Within the hour, Xcel generating resources are controlled by the Energy Management System to follow the changes in the load. Some of these changes can be categorized as "regulation", which was analyzed in a previous section. Others, however, are of longer duration and reflect the underlying trends in the load – ramping up in the morning and down late in the day. Still others could be due to longer-term variations about general load trend with time. The nature of these changes can be simply quantified by looking at the MW change in load value from one ten minute interval to the next.

Energy impacts would stem from non-optimal dispatch of units relegated to follow load as it changes within the hour. The faster fluctuations up and down about a longer term trend, determine the regulation requirements as discussed before. These fluctuations were defined to be energy neutral – i.e. integrated energy over a period is zero. The energy impacts on the load following time frame thus do not include the regulation variations, but are driven by longer term deviations of the control area demand from an even longer term trend. Additional production costs (compared with those calculated on an hourly basis, for control area load that remains constant for the hour) result from the load following units dispatched to different and possibly non-optimal operating levels to track the load variation through the hour.

The additional costs of this type attributable to wind generation are related, then, to how it alters the intra-hourly characteristic of the net control area demand. High-resolution load data provided by Xcel Energy and scaled to the year 2010 along with wind generation data from the numerical simulation model were analyzed to elicit the characteristics of this behavior at ten-minute intervals.

Figure 13 shows a weekly trend of the changes from one ten-minute interval to the next for the system load and wind generation. It is apparent from the plot that the load exhibits significantly more variability than does wind generation.

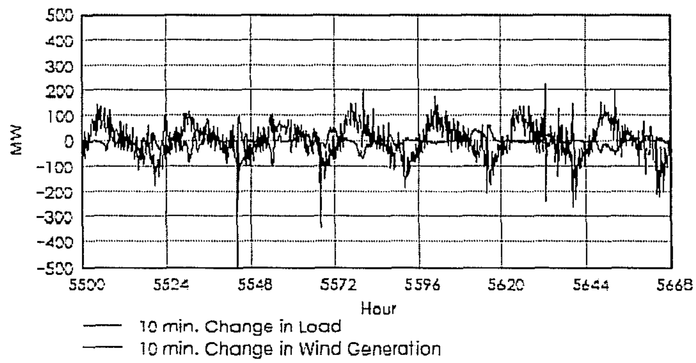


Figure 13: Weekly time series of ten-minute variations in load and wind generation.

An entire year of data – almost 50,000 ten-minute data points - was analyzed to develop a statistical distribution of these changes (Figure 14). The results show that wind generation has only a minor influence on the changes from one interval to the next, and most of the effect is to increase the relatively small number of larger-magnitude changes.

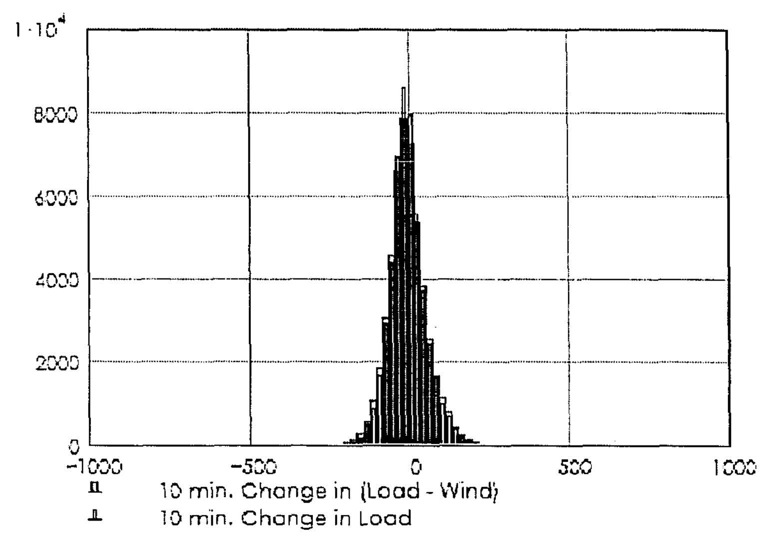


Figure 14: Control area net load changes on ten minute intervals with and without wind generation.

The same data was also analyzed to examine the variation from a longer term trend that tracks the hour-by-hour daily load pattern. The distributions of these variations with and without wind generation over the year of data are shown in Figure 15.

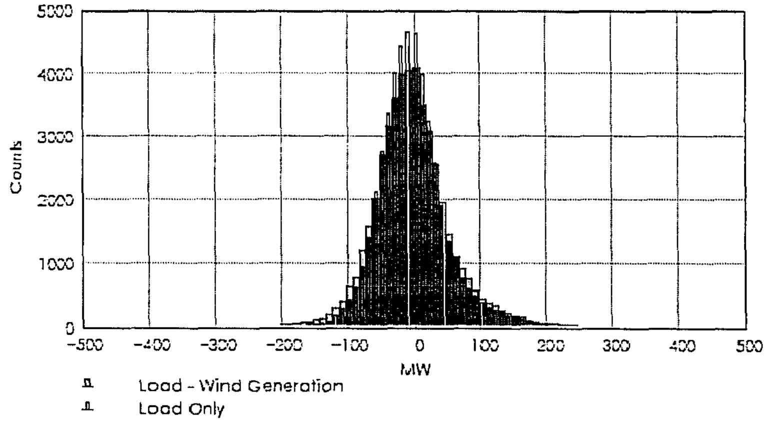


Figure 15: Variation at ten-minute increments from daily "trend" pattern, with and without wind generation.

The numerical results are similar to those described previously that considered the absolute changes on ten-minute increments. The standard deviation of the distribution of deviations from the hourly trend for the load only is 53.4 MW; with wind generation in the control area, the standard deviation increases to 64 MW.

In the earlier study, results from simulations of a limited number of "typical" hours along with several simplifying assumptions were extrapolated to annual projections. A cost impact of $0.41/MWH was assigned to wind generation due the variability at a time resolution of five minutes. However, one of the major simplifications was that only the wind generation exhibited significant variability from a smooth hourly trend, so that all costs from the intra-hourly simulations beyond those calculated at the hourly level could be attributed to wind generation.

The data analyses here lead to a different conclusion. The system load does vary significantly about a smoother hourly trend curve, and may also vary substantially from one ten-minute interval to the next. With this as the backdrop, it was shown that the addition of wind generation to the control area would have only slight impacts on the intra-hour variability of the net control area demand. It also appears that the corresponding changes in wind generation and those in the system load are uncorrelated, which substantially reduces the overall effect of the variations in wind generation within the hour.

In quantitative terms, for the system load alone, just over 90% of the ten-minute variations from the hourly trend value are less than 160 MW. With wind generation, that percentage drops to 86%, or stated another way, 90% of the ten-minute variations from the hourly trend value are less than 180 MW.

The original project plan called for simulations to be used for quantifying the energy cost impacts at the sub-hourly level. This was the approach taken in the earlier study of the Xcel system, and thought to be the most direct method for this assessment. In light of the results of the intra-hourly data analysis, it was determined detailed chronological simulations would be of very limited value for determining any incremental cost impacts for intra-hourly load following. With a very slight effect on the characteristics of the intra-hourly control area demand characteristic as evidenced by the approximately 10 MW change in the standard deviations, calculated effects on production cost would likely be in the "noise" of any deterministic simulations.

Based on the analysis here, it is concluded that the $0.41/MWH of wind generation arrived at in the previous study was artificially high since the load was assumed to vary smoothly during the hour. Also, the statistical results presented here support the conclusion that the increase in production cost on an intra-hourly basis due to the wind generation considered here would be negligible.

The results do show, however, that wind generation may have some influence on control performance as the number of large deviations from one interval to the next or from the longer-term trend of the net control area demand is significantly increased. An expansion of the distributions of ten-minute changes with and without wind generation is shown in Figure 16. Wind generation substantially increases the number of larger-magnitude excursions over the course of the year.

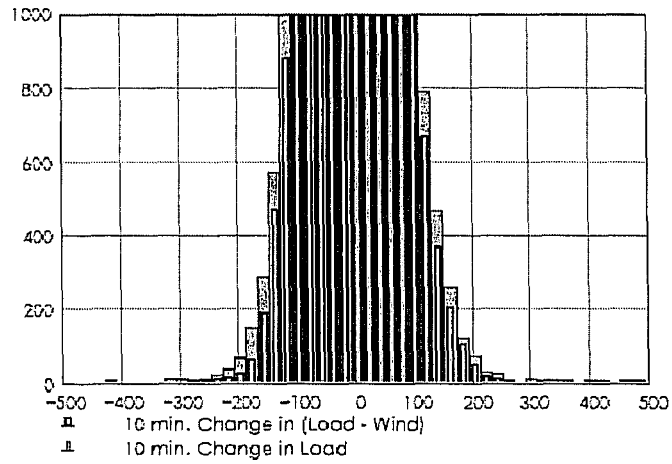


Figure 16: Expanded view of Figure 14.

The total number of these large excursions is not significant from an energy standpoint, since the number is a small fraction of the total number over the year. There are implications, however, for control performance of the Xcel system. To assess this potential impact, increases in the occurrences of control area demand change of a given magnitude were "counted". Table 5 shows the number of occurrences over the sample year of data where the net control area load (load minus wind generation) changed more than a given amount (up or down) in one ten minute period.

Table 5: Ten-minute Variations in Control Area Demand, with and without Wind Generation

	# of Occurrences		
10 min. Change	System Load	System Load with Wind	Difference
greater than +/- 100 MW	5782	7153	1371
greater than +/- 120 MW	3121	4148	1027
greater than +/- 140 MW	1571	2284	713
greater than +/- 160 MW	730	1246	516
greater than +/- 200 MW	165	423	258
greater than +/- 400 MW	26	92	66
greater than +/- 600 MW	18	44	26

With a ramping capability of 140 MW per ten minute period, control performance (CPS2, in NERC terminology) would be comfortably above the minimum requirement with or without wind generation. Or, from another perspective, if the current CPS2 performance is 94%, maintaining that performance level with the addition of 1500 MW of wind generation would require somewhere between 1 and 2 MW/minute of additional load following capability.

Conclusions

The analysis conducted in this task indicates that the cost of integrating 1500 MW of wind generation into the Xcel control area in 2010 are no higher than $4.60/MWH of wind generation, and are dominated by costs incurred by Xcel to accommodate the significant variability of wind generation and the wind generation forecast errors for the day-ahead time frame.

The total costs include about **$0.23/MWH** as the opportunity cost associated with an 8 MW increase in the regulation requirement, and **$4.37/MWH** of wind generation attributable to unit commitment and scheduling costs. The increase in production cost due to load following within the hour was determined by a statistical analysis of the data to be negligible. The intra-hour analysis also showed that an incremental increase in fast ramping capability of 1-2 MW/minute would be necessary to maintain control performance at present levels. This specific impact was not monetized.

The analytical approach for assessing costs at the hourly level in this study compares the actual delivery of wind energy to a reference case where the same daily quantity of wind energy is delivered as a flat block. In addition to costs associated with variability and uncertainty, the total integration cost then will contain a component related to the differential time value of the energy delivered. If more wind energy is actually delivered "off-peak" relative to the reference case, when marginal costs are lower, this differential value will show up in the integration cost. The total integration cost calculated by this method is still a meaningful and useful value, but care must be taken not to ascribe all of the integration cost to uncertainty and variability of wind generation output.

Wind generation also results in a much larger ramping requirement from hour to hour. The costs associated with this impact are captured by the hourly analysis, as the unit commitment and schedule must accommodate any large and sudden changes in net control area demand in either the forecast optimization case, or in the simulation with actual wind generation. In the optimization case that utilizes wind generation forecast data, generating resources must be committed and deployed to follow control area demand while avoiding ramp rate violations. In the simulation cases with actual wind generation, changes due to wind generation that cannot be accommodated result in "unserved energy" in the parlance of the unit commitment software, which really means that it must be met through same-day or more probably next-hour purchases.

Some specific conclusions and observations include:

1. While the penetration of wind generation in this study is low with respect to the projected system peak load, there are many hours over the course of the year where wind generation is actually serving 20 to 30% (or more) of the system load. A combination of good plans, the right resource mix, and attractive options for dealing with errors in wind generation forecasts are important for substantially reducing cost impacts.
2. That said, the cost impacts calculated here are likely to be somewhat overstated since little in the way of new strategies or changes to practices for short-term planning and scheduling were included in the assumptions, and since the hour-ahead adjustments in the study are made at a price closer to the marginal cost of internal resources than those in a liquid wholesale energy market.
3. The incremental regulation requirement and associated cost for accommodating 1500 MW of wind generation, while calculable, is quite modest. The projected effect of geographic diversity together with the random and uncorrelated nature of the wind generation fluctuations in the regulating time frame, as shown by the statistical analysis, have a dramatic impact on this aspect of wind generation.
4. Large penetrations of wind generation can impact the hourly ramping requirements in almost all hours of the day. On the hourly level, this results in deployment of more resources to follow the forecast and actual ramps in the net system load, thereby increasing production costs.
5. Wind generation integration costs are sensitive to the deployment of units, which is also a function of the forecast system load. The results seem to indicate that these costs can be high over a period when expensive resources are required to compensate for the hourly variability, even when the total wind generation for the period might be low.
6. For the study year of 2010, the cost of integrating 1500 MW of wind generation into the Xcel-NSP control area could be as high as $4.60/MWH of wind energy where the hour-by-hour forecast of wind for 16 to 40 hours ahead has a mean absolute error of 15% or less. The total integration cost is dominated by the integration cost at the hourly level, and assumes no significant changes to present strategies and practices for short-term unit commitment and scheduling.
7. The MISO market cases demonstrate that the introduction of flexible market transactions to assist with balancing wind generation in both the day-ahead scheduling process and the day one hour ahead has a dramatic positive impact on the integration costs at the hourly level. For example, in August the hourly cost was reduced by two thirds.

Results of the hourly analysis are considered to be quite conservative - they are on the high end of the range of results that could be generated by varying the assumptions. While the methodology is relatively robust and thought by the researchers to be straightforward and consistent with industry practice, a number of assumptions were made to facilitate analysis of a large set of sample days - two years of days unique in peak load, load pattern, actual and forecast wind generation. The input data for the hourly analysis was developed in such a way that any correlations between Xcel control area load and the wind resource in the upper Midwest are actually embedded in the datasets.

Much of the conservatism in the hourly analysis stems from the simplification of many decisions that would be made by knowledgeable schedulers, traders, and system operators to reduce system costs and/or increase profits. This leads to the use of resources which are under the control of the unit commitment program to accommodate the variability of wind generation and the day-ahead wind generation forecast errors. In months with higher electric demand, these resources can be relatively expensive.

Energy purchases and sales are a potential alternative to internal resources. In the hourly analysis, these transactions were fixed, not allowing for the day-ahead flexibility that might currently exist for judicious use of inexpensive energy to offset the changes in wind generation. Optimizing these transactions day by day would have prevented evaluation of the statistically significant data set of load and wind generation, and would have been to difficult to define objectively.

Given the likely sources of the integration cost at the hourly level, it is apparent that a better strategy for purchase and sale transactions scheduled even day-ahead would reduce integration costs at the hourly level. This leads naturally to considering how wholesale energy markets would affect wind integration costs.

The planning studies conducted by MISO show that wholesale energy is relatively inexpensive in the upper Midwestern portion of their footprint. Transmission constraints do come into play on a daily and seasonal basis, but interchange limits for most of Minnesota are reasonably high relative to the amount of wind generation considered in this study. The ability to use the wholesale energy market as a balancing resource for wind generation on the hourly level has significant potential for reducing the integration costs identified here.

Wholesale energy markets potentially have advantages over bi-lateral transactions as considered simplistically in this study. In day-ahead planning, for example, it would be possible to schedule variable hourly transactions consistent with the forecast variability of the wind generation. Currently, day-ahead bi-lateral transactions are practically limited to profiles that are either flat or shapeable to only a limited extent. Hour-ahead purchases and sales at market prices would provide increased flexibility for dealing with significant wind generation forecast errors, displacing the more expensive units or energy fire sales that sometimes result when relying on internal resources.

Task 1: Wind Resource Characterization

Task Description

- Provide an overview and characterization of Midwest wind patterns and resulting wind generation patterns.
- Assess the forecast accuracy of wind generation on a day-ahead basis and assess the implications on the degree of certainty that is included in the forecast.
- Appropriately scale up historical wind data and develop a representative wind plant model, in coordination with the National Renewable Energy Laboratory, for the 1500 MW of wind generation in the study. Evaluate the extent of wind generation variability that the NSP system should experience, including the effects of projected wind turbine technology and projected geographic diversity for the study year of 2010.

Introduction

A major impediment to obtaining a better understanding of how large amounts of wind generation would affect electric utility control area operations and wholesale power markets is the relative lack of historical data and experience with large wind plants.

Measurement data and other information have been compiled over the past few years on some large wind plants across the country. The Lake Benton plants at the Buffalo Ridge substation in southwestern Minnesota have been monitored in detail for several years. The understanding of how a single large wind plant might behave is much better today than it was five years ago.

In this study, knowing how all of the wind plants in the 1500 MW scenario appear in the aggregate to the Xcel system operators and planners is one of the most important aspects of the study. That total amount of wind generation will likely consist of many small and large facilities spread out over a large land area, with individual facilities separated by tens of miles up to over two hundred miles.

The wind speed at any point is the result of extremely complicated meteorological processes, which might lead one to conclude that a wide range of conditions would be found at all of the wind facility sites in the scenario. At the same time, these wind speeds are driven by the same overall meteorology, so correlation between the sites at some levels and time scales would be expected. The challenge, then, is to somehow construct a model that considers not only the differences but captures the correlations. Conservative or simplistic assumptions like locating the entire 1500 MW of wind generation in the Lake Benton area, or spreading out wind plants modeled on those at the Buffalo Ridge substation (for which ample measurement data exists) and neglecting the correlations that exist between plants would only lead to suspect conclusions.

The approach for this study was to utilize sophisticated meteorological simulations and archived weather data to "recreate" the weather for selected past years, with "magnification" in both space and time for the sites of interest. Wind speed histories from the model output for the sites at heights for modern wind turbines were then converted to wind generation histories.

This section provides background on the factors that drive the wind in the upper Midwest, and describes the model and methodology employed for building the wind generation model. It concludes with a discussion of wind speed and wind generation forecasting. A more detailed characterization of the wind resource in the upper Midwest was also developed as part of this study. These results are published as a separate volume.

Wind Resource Characterization

Controlling Meteorology for the Upper Midwest

The climatology of wind in the Upper Midwest exhibits significant seasonal variability. The essential meteorology driving the wind resource is largely controlled by the position and strength of the upper-level jet stream and disturbances (jet streaks) within the jet stream. As shown in Fig. 17, the jet stream position in the winter season is both farther south and stronger than in the summer. In the transition seasons of spring and fall, the average jet stream position generally lies between these locations. The main factor controlling both the jet stream position and speed is the magnitude and location of the tropospheric meridional (north-south) temperature gradient. A larger (smaller) temperature gradient exists in the winter (summer) and corresponds to a stronger (weaker) jet stream. Note that although Figure 17 indicates a mean ridge axis over western North American and trough axis over eastern North American, at any particular time (e.g., day, week, or even several week period), the jet stream orientation and strength could be very different from that indicated in Figure 17.

The jet stream position can be thought of as the current "storm track". In this context, "storm track" means the track of mid-latitude cyclones and anticyclones (i.e., low and high pressure systems of one to several thousand kilometer horizontal dimension) seen on a meteorological pressure and geopotential height analysis maps. Weather phenomena of this size are called *synoptic* scale systems. In general, the stronger the jet stream and jet streaks, the more intense the lower-tropospheric pressure systems due to the dynamic link between the upper and lower troposphere. The key factor driving the wind resource in the lowest 100 m of the atmosphere is the horizontal pressure gradient. Large pressure gradients are associated with the transient cyclones and anticyclones, thus, if a region is co-located near the storm track, that region will realize higher wind speed than a region farther away from the storm track. Figure 18 provides a schematic of typical cyclone tracks that influence the Upper Midwest. The northwest-southeast track represents a common storm track in all seasons. The southwest-northeast track, although less common and usually relegated to transition and winter seasons, can correspond to large and intense cyclones. On the time scale of a several hours to approximately one day, fronts attendant to the transient cyclones have a large influence on wind variability. In summary, the seasonal wind resource is largely controlled by the jet stream position and frequency of associated cyclone and anticyclone passages over the region. The best wind resource for the Upper Midwest is expected with the stronger low-level pressure gradients of the winter and transition seasons while the weaker pressure systems of summer yield a reduced wind resource.

Superposed on the background low-level meteorological pattern of high and low pressure systems are the diurnal effects of the solar insulation cycle and their influence on thermal stability and boundary layer evolution. On this diurnal time scale, low-level wind speed variability is highly influenced by the vertical transport of momentum. An important feature in the Upper Midwest (and other Plains and near-Plains geographical locations) is the nocturnal low-level jet that develops when low-momentum near-surface air no longer mixes vertically due to the development of the shallow nocturnal inversion. So while the lowest levels may experience their weakest wind speeds of the day, in the layers just above the surface layer (> ~30-40 m) this results in dramatically reduced surface-based drag and acceleration to speeds frequently greater than those seen during the daytime.

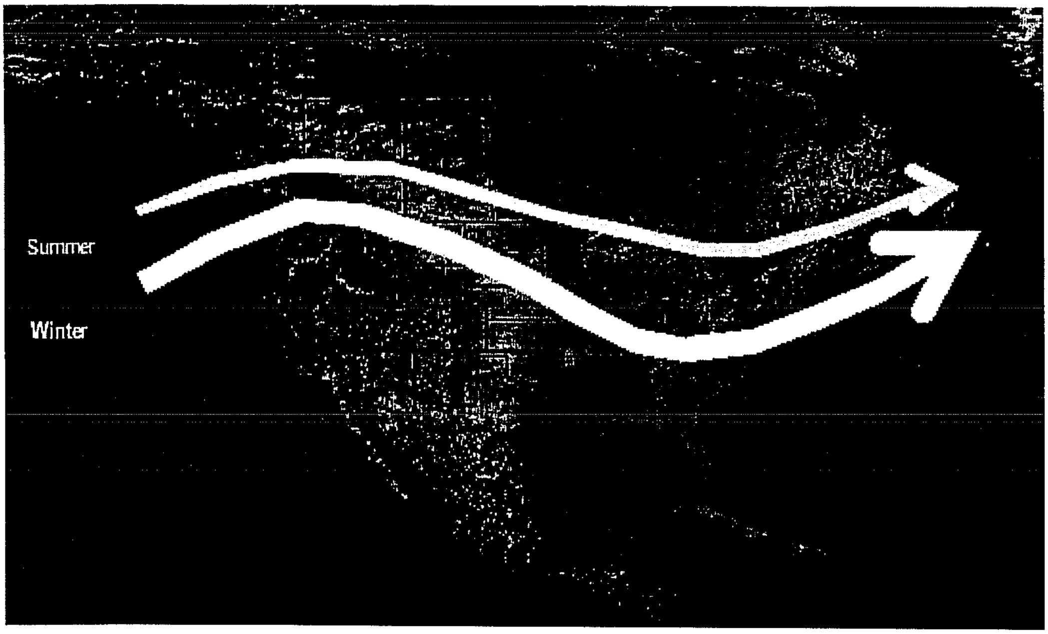


Figure 17: Mean winter and summer positions of the upper-tropospheric jet stream. Line width is indicative of jet stream wind speed

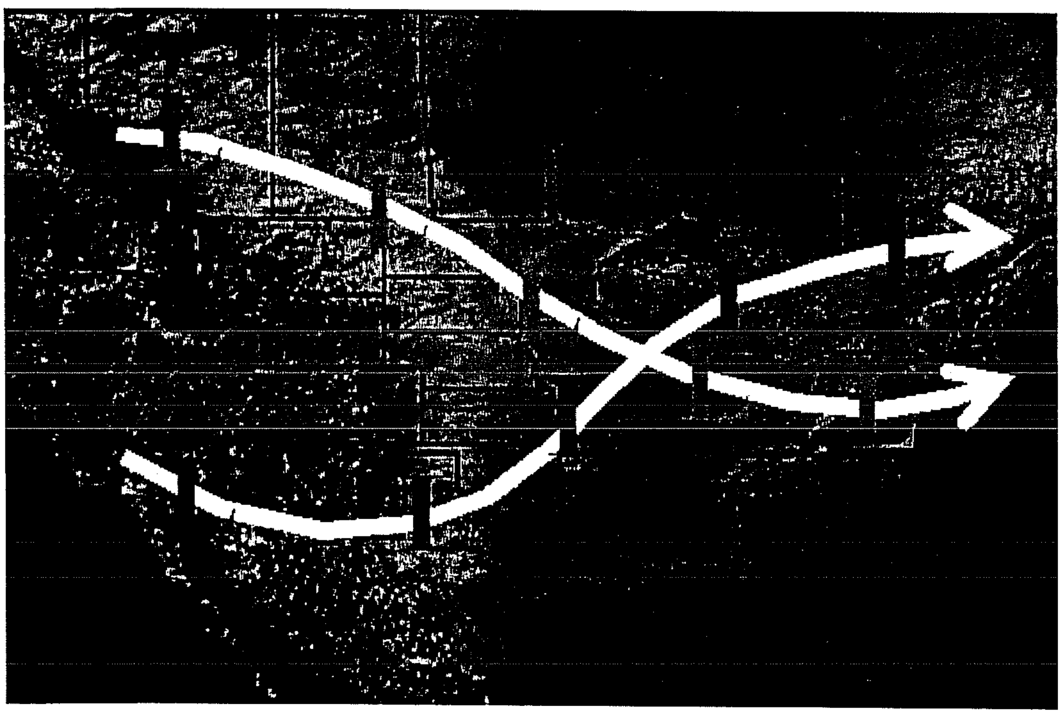


Figure 18: Typical "storm tracks" that influence the wind resource of the Upper Midwest. The bold Ls represent surface cyclone positions as they move along the track.

On the shorter time scale of tens of minutes to several hours, wind variability is frequently influenced by thunderstorm outflow boundaries during the convective season (late spring through early fall).

These outflow boundaries can range in size from only a few kilometers to hundreds of kilometers in horizontal extent. Outflow strength and size are usually dependent on the degree of organization of the convective system and the thermodynamic environment the thunderstorms develop in. Note that in all environmental conditions, the very small time scale wind speed variability (seconds to 10s of seconds) is controlled by boundary layer turbulence.

Modeling Methodology and Utilization of Weather Archives

To evaluate the historic wind resource and variability (over several time scales) of southern Minnesota and eastern South Dakota, the MM5 mesoscale atmospheric model (Grell et al. 1995) was utilized. This prognostic regional atmospheric model is capable of resolving meteorological features that are not well-represented in coarser-grid simulations from the standard weather prediction models run by the National Center for Environmental Prediction (NCEP). The MM5 was run in a configuration utilizing 3 grids with finer internal nests as shown in Figure 19. This "telescoping" 2-way nested grid configuration allowed for the greatest resolution in the area of interest with coarser grid spacing employed where the resolution of small mesoscale meteorological phenomena was not as important. This methodology was computationally efficient while still providing the necessary resolution for accurate representation of the meteorological phenomena of interest in the innermost grid. More specifically, the 5 km innermost grid spacing was deemed necessary to capture terrain influences on boundary layer flow and resolve mesoscale meteorological phenomena such as thunderstorm systems. The 45, 15 and 5 km grid spacing utilized in grids 1, 2, and 3, respectively, yield the physical grid sizes of: 2700 x 2700 km for grid 1, 1050 x 1050 km for grid 2, and 560 x 380 km for grid 3.

To provide an accurate simulation of the character and variability of the wind resource for eastern South Dakota and southern Minnesota, 3 full years of MM5 model simulations were completed. To initialize the model, the WindLogics archive of NCEP's Rapid Update Cycle (RUC) model analysis data was employed. The years selected for simulation were 2000, 2002 and 2003. The RUC analysis data was used both for model initialization and for updating the model boundary conditions every 3 hr. This RUC data had a horizontal grid spacing of 40 km for 2000 and 20 km for 2002 and 2003. To ensure that the model was properly representing the larger scale meteorological systems and to avoid model drift, the MM5 simulations were restarted every day with a new initialization.

To support the development of the system integrated wind model, data at 50 grid points (proxy towers) in the innermost model nest were extracted every 10 min as the simulation progressed. This process ensured that an analysis of the character and variability of the wind resource over several time scales could be performed at geographically disperse but favored locations. Figure 20 depicts the MM5 innermost grid and the locations selected for high time resolution data extraction. The locations were selected to 1) correspond to existing wind farm locations, and 2) to represent a more geographically disperse Buffalo Ridge distribution while also including the greater geographical dispersion provided with Mower County sites. In particular, 5 sites were located in each of 10 counties where, *a priori*, the wind resource was expected to be good. Data extracted at each site included wind direction and speed, temperature and pressure at an 80 m hub height. The non-wind variables were extracted to calculate air density that is subsequently used along with the wind speed in turbine power calculations.

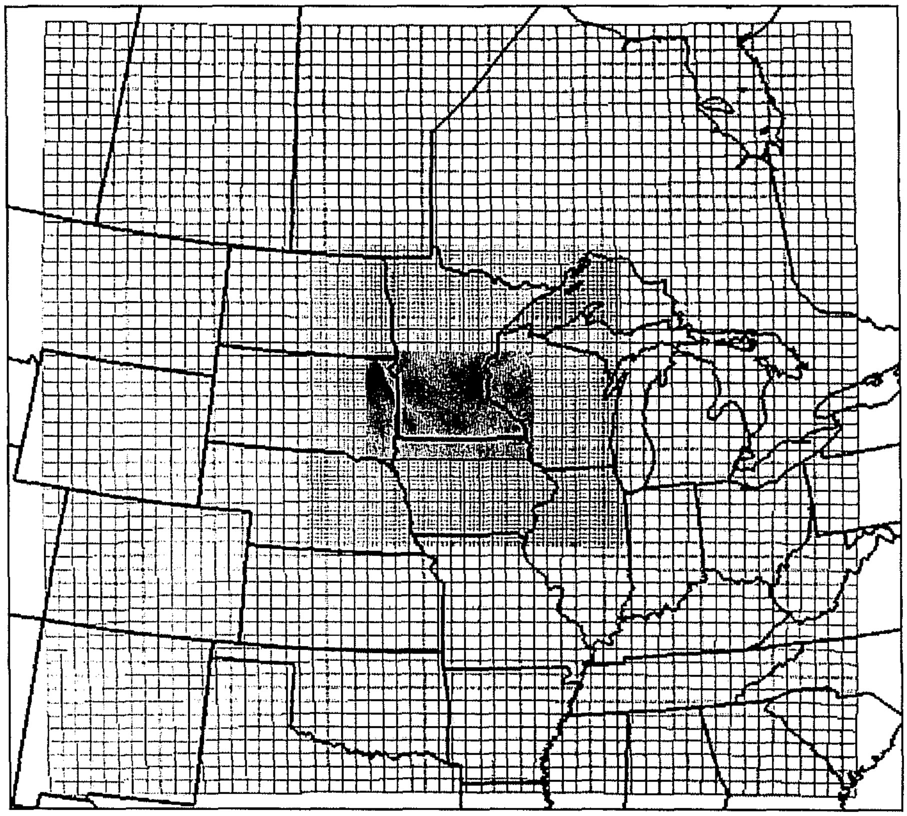


Figure 19: MM5 nested grid configuration utilized for study area. The 3 grid run includes 2 inner nested grids to optimize the simulation resolution in the area of greatest interest. The grid spacing is 45, 15 and 5 km for the outer, middle and innermost nests, respectively. The colors represent the surface elevation respective to each grid.

Normalization of Model Wind Data with Long-Term Reanalysis Database

To more accurately characterize the historic wind resource over the Xcel wind integration study area, the MM5 wind speed data was normalized with the WindLogics archive of the National Center for Atmospheric Research (NCAR)/NCEP Reanalysis Database (RNL). This RNL database represents 55 years of atmospheric data that is processed through a modeling assimilation cycle to ensure dynamic consistency. This RNL database is the best objective long- term dataset available and was created for purposes such as climate research investigations. By comparing applicable RNL grid points for a given month and year to the long-term average at those points, ratios are created that are applied to the MM5 wind data (including all proxy tower extractions). This process normalizes the model data to better represent the historic character of the wind resource.

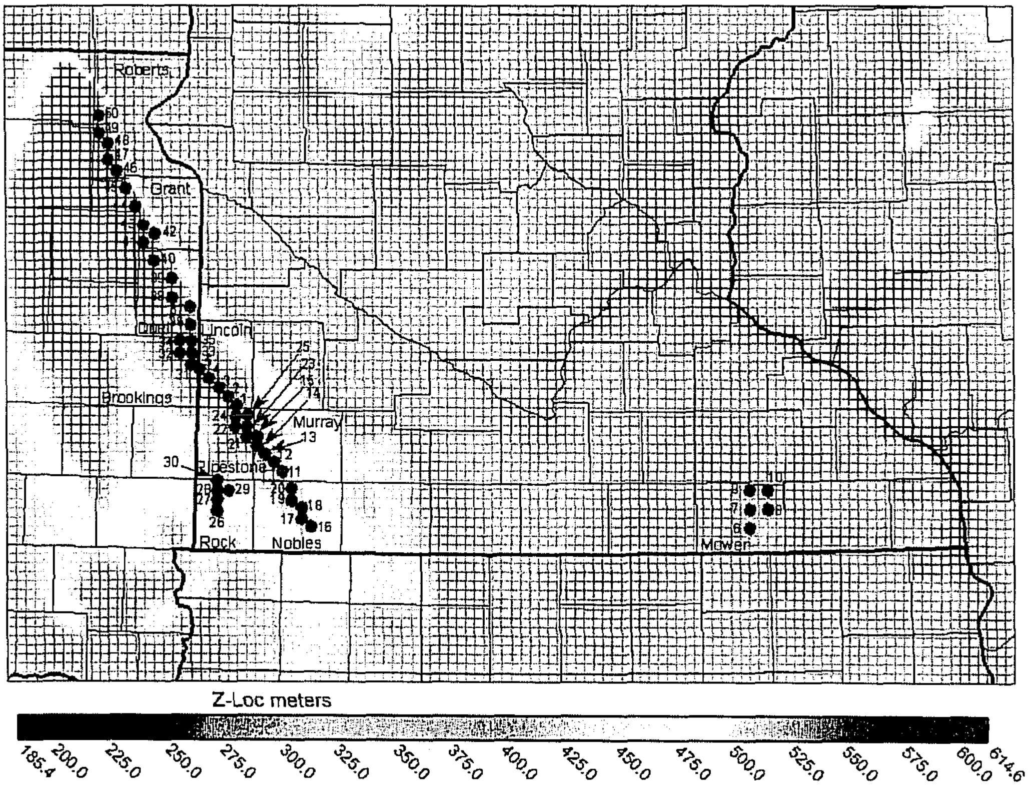


Figure 20: Innermost model grid with proxy MM5 tower (data extraction) locations. The color spectrum represents surface elevation.

Validation of Modeled Winds

To assess the degree to which the MM5 numerical model simulated the actual meteorology occurring over southern Minnesota, and importantly, the temporal variability of the wind, a comparison was made between the model output and known power production data from the Delta Sector in the Lake Benton II wind farm. This exercise entailed taking an entire year of model data for 2003 and making an hour by hour comparison with site data.

Description of Multi-Scale Aspects of Modeled Wind Variability

The meteorological variability of the region and related wind resource variability may be categorized by the inherent time-scale of the phenomena. On the one to several day time scale, the passage of synoptic weather systems (cyclones and anticyclones) exert a large influence on the wind variability. Typically, attendant fronts associated with cyclone passages may impose significant wind speed variability on a time scale of several hours to one day. On the diurnal time scale, boundary layer stability influenced by solar insolation cycles controls the vertical transport of momentum and wind speed variability. Related to the diurnal evolution of the atmospheric boundary layer, nocturnal low-level jets are a common phenomenon over the study region, especially in the summer and early fall months. These nocturnal low-level jet episodes induce large variations in the diurnal wind resource above the shallow nocturnal inversion. On time scales of tens of minutes to several hours, convective phenomena such as thunderstorms and thunderstorm complexes with their associated outflows have a large influence on low-level wind variability. In the time scale of seconds to tens of seconds, boundary layer turbulence controls wind speed variability. On the small time and space scales of turbulence, the numerical model employed is not capable of resolving these features.

NREL Database, Comparison Methodology, and Model Output Loss Factor Adjustment

NREL power production data was obtained for the Delta Sector of the Lake Benton II Wind Farm for 2003. Of the 4 sectors of Lake Benton II, the Delta Sector was selected due to its geographical overlap with MM5 proxy Tower 24. The Delta Sector aggregate power data was quality controlled for periods where large numbers of turbines were off-line by comparing this sector's power output trends to the 3 other quadrants of Lake Benton II. A running 10 min average was applied to the NREL database to eliminate small time scale noise. The NREL data was further reduced to 1 hr time increments to make the hourly comparison with the model data for an entire year tractable.

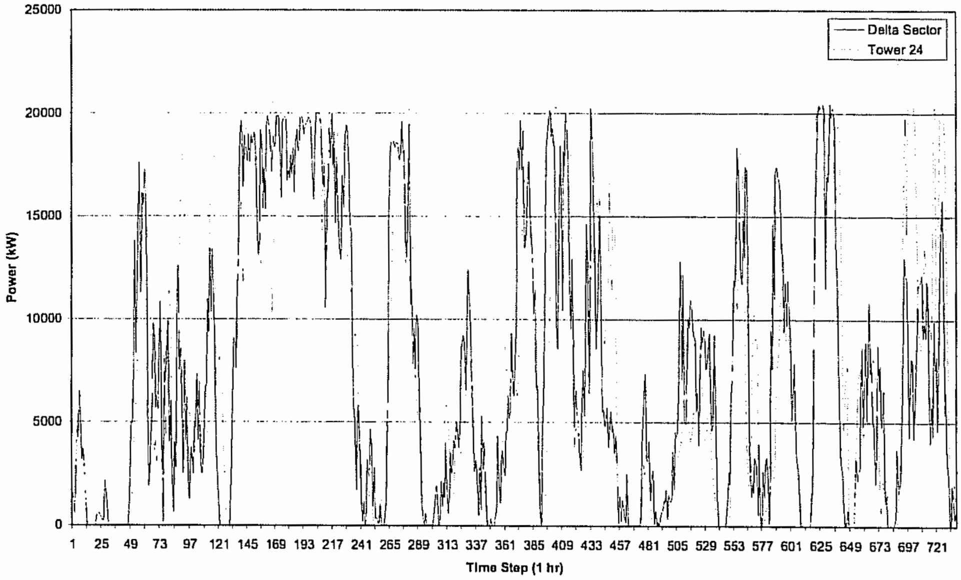
For the validation, MM5 Tower 24 power production was based on the meteorological conditions at hourly intervals at the 52 m hub height of the Delta Sector turbines. The MM5 wind data was not normalized to the long term RNL dataset for this validation analysis. Power curve data for the Zond-750 was applied to obtain the appropriate power production commensurate with the wind speed and density values. The MM5 Tower 24 power values were then multiplied by the number of turbines in the Delta Sector (30) such that the model-derived power could be compared to the NREL aggregate power values.

To represent various losses in the model data (transmission, collection, array, off-line turbines, etc), a 10 % loss factor was applied to all the model power values. This value was arrived at by plotting out the NREL Delta Sector power time series and evaluating the power production values during periods throughout the year when this wind farm sector was obviously on the top plateau of the power curve. The difference in power between what was actually being produced and the theoretical capacity value for the Delta Sector enabled a loss factor to be estimated (10 %). This methodology likely did not represent the full extent of the array losses but, when applied to the model power data, this 10 % adjustment produced model peak power production periods representative of those exhibited by the Delta Sector. A more conservative loss adjustment value was utilized in the wind resource temporal variability and geographic dispersion analysis.

Validation for 2003 – Monthly Comparison Time Series and Statistics

MM5 Tower 24 and Delta Sector power time series comparison plots for all the months of 2003 are presented in Figure 21 through Figure 26. The MM5 simulation demonstrates a high degree of skill in capturing meteorological variability on all the relevant time scales. The model trends (power time gradients) compare very favorably with the Delta Sector time series trends. In comparing seasonal model performance, the MM5 clearly produces a higher quality solution in the winter and transitional seasons that are dominated by synoptic-scale systems. Due to their size and intensity, these synoptic systems are better resolved by the model, and thus, the model simulates the wind resource more accurately. The much weaker summer weather systems and warm season convective episodes are much more difficult to simulate. Convection is inherently difficult to model due to its relatively short life span and often small horizontal dimension. Additionally, simulating the timing and position of convective initiation is a substantial challenge. However, even in the summer months, the model demonstrates some skill in simulating short time scale events while being less accurate on event magnitudes. As an assessment of model performance, the mean error for 7 months is less than 6 % of capacity with no months having a mean error greater than 8.9 % of capacity. The mean absolute error is less than 15% of capacity for 6 months with no months having a mean absolute error of greater than 18.9 % of capacity. In terms of time series comparative correlation, 8 months had correlation coefficients of 0.78 or greater. No operational status information was provided with the NREL power data, so it was not possible to account for errors resulting from a variable number of turbines operating correctly due to maintenance or weather related events such as icing.

1.72	ME as % of Cap
12.82	MAE as % of Cap
0.82	Correlation



2.38	ME as % of Cap
14.23	MAE as % of Cap
0.79	Correlation

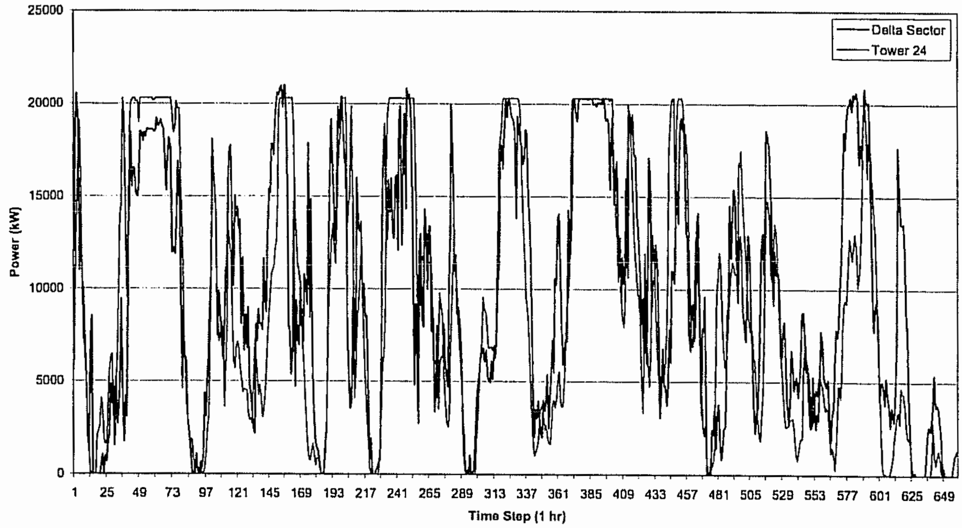
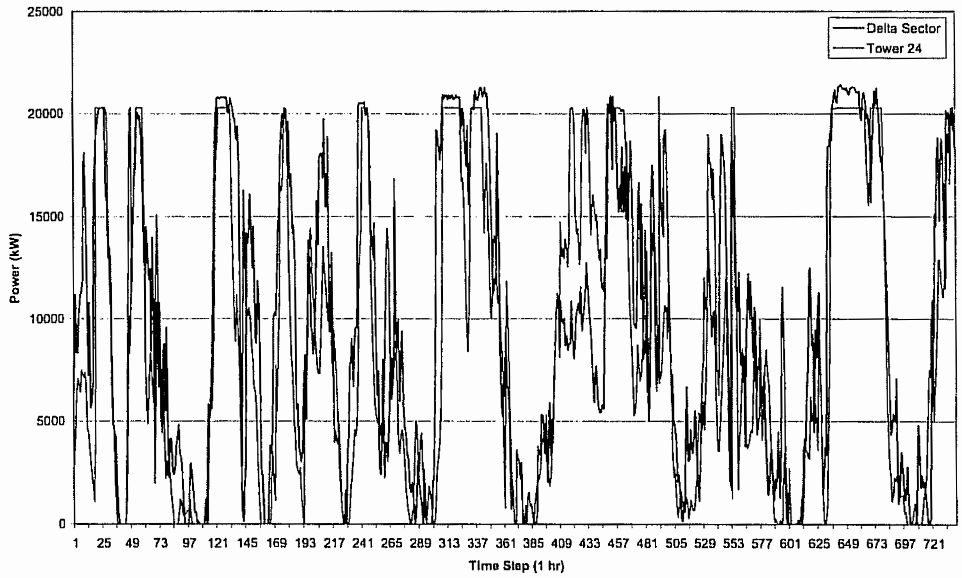


Figure 21: January (top) and February (bottom) power time series for MM5 Tower 24 and the Delta Sector. Mean error (ME), mean absolute error (MAE) and correlation coefficient are shown in the upper right box.

5.87	ME as % of Cap
14.8	MAE as % of Cap
0.81	Correlation



4.33	ME as % of Cap
15.62	MAE as % of Cap
0.79	Correlation

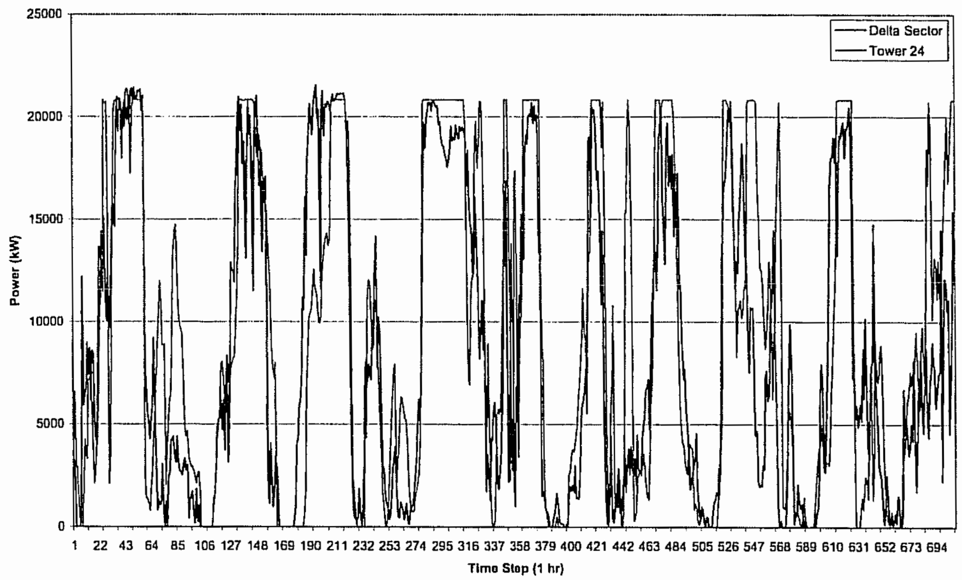
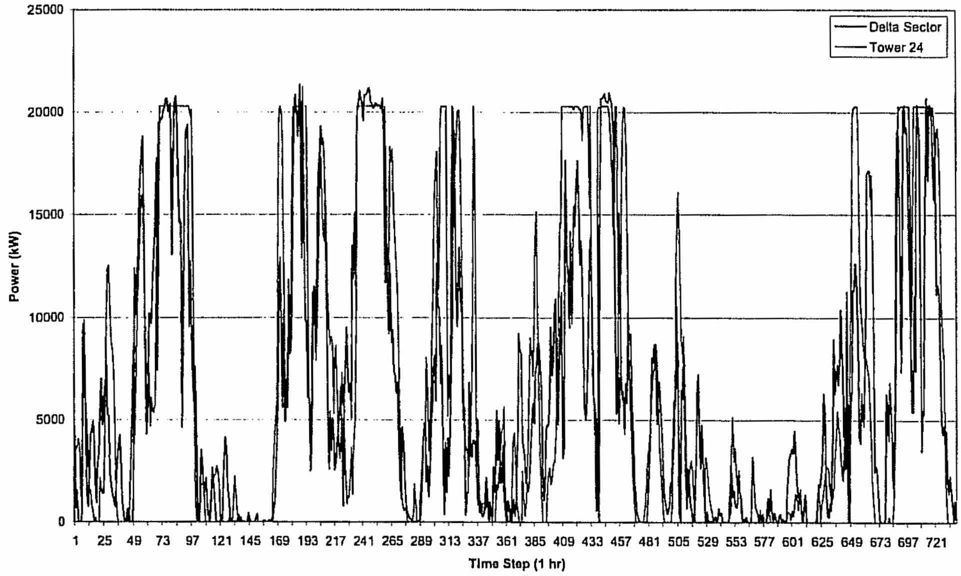


Figure 22 March (top) and April (bottom) power time series for MM5 Tower 24 and the Delta Sector. Mean error (ME), mean absolute error (MAE) and correlation coefficient are shown in the upper right box.

7.58	ME as % of Cap
15.52	MAE as % of Cap
0.80	Correlation



7.39	ME as % of Cap
15.03	MAE as % of Cap
0.75	Correlation

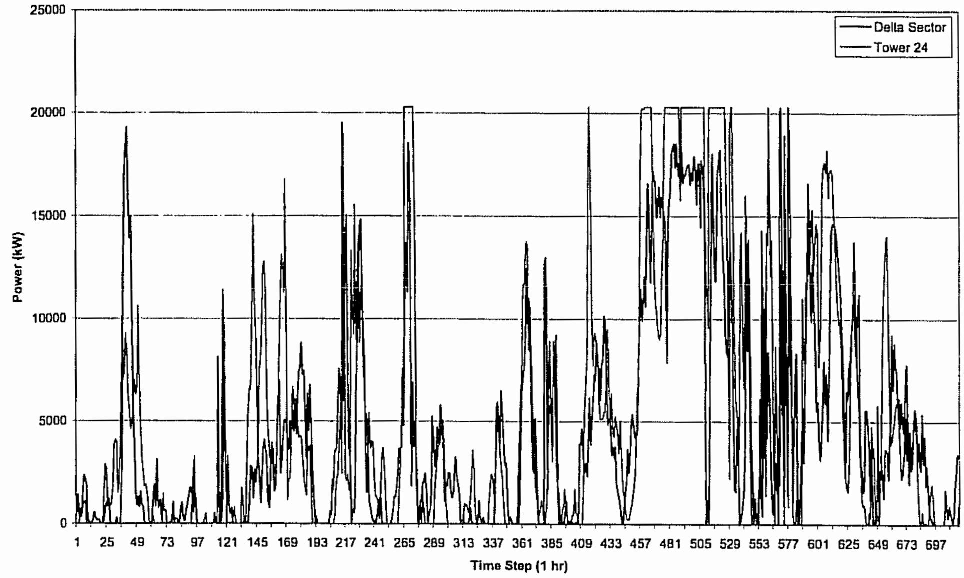
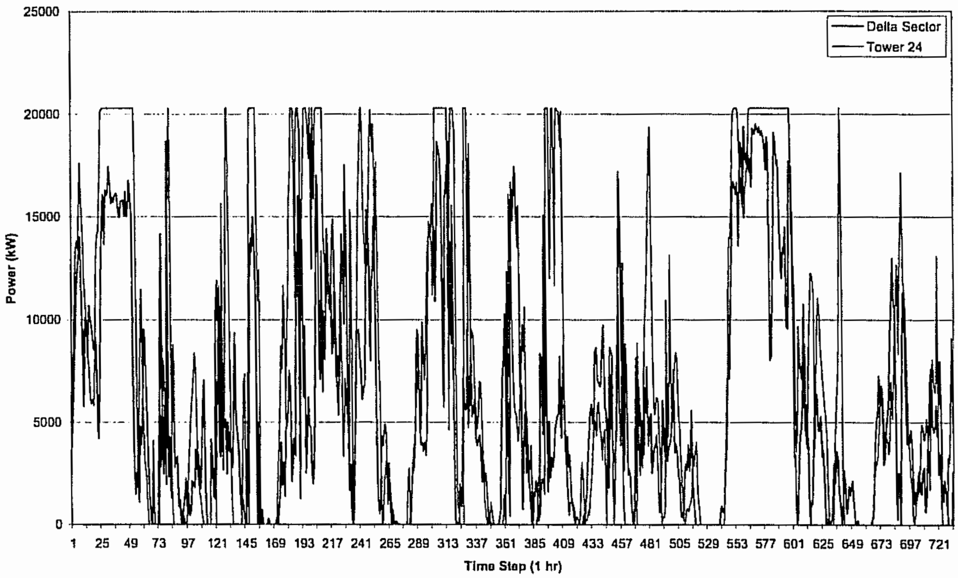


Figure 23: May (top) and June (bottom) power time series for MM5 Tower 24 and the Delta Sector. Mean error (ME), mean absolute error (MAE) and correlation coefficient are shown in the upper right box.

8.46	ME as % of Cap
17.99	MAE as % of Cap
0.67	Correlation



8.30	ME as % of Cap
14.63	MAE as % of Cap
0.75	Correlation

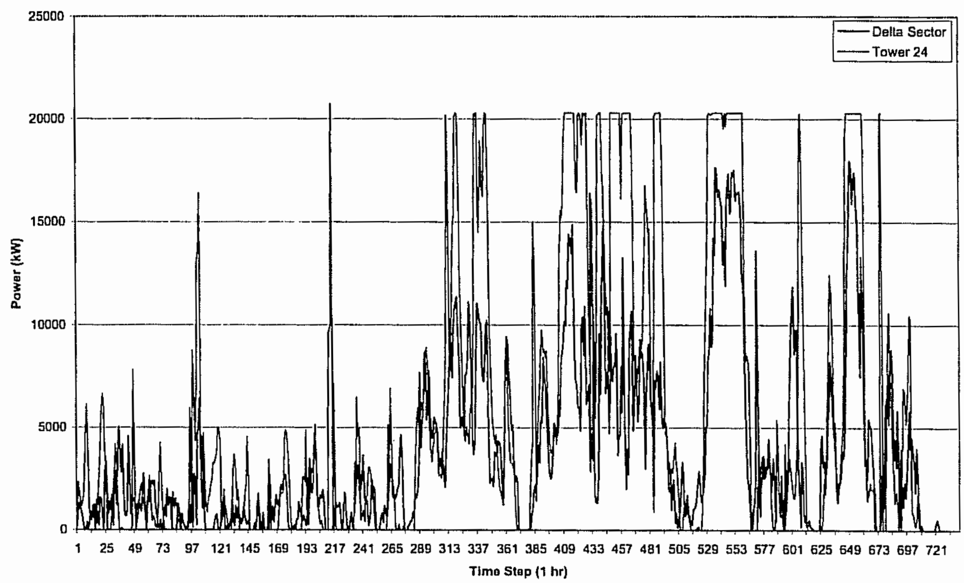
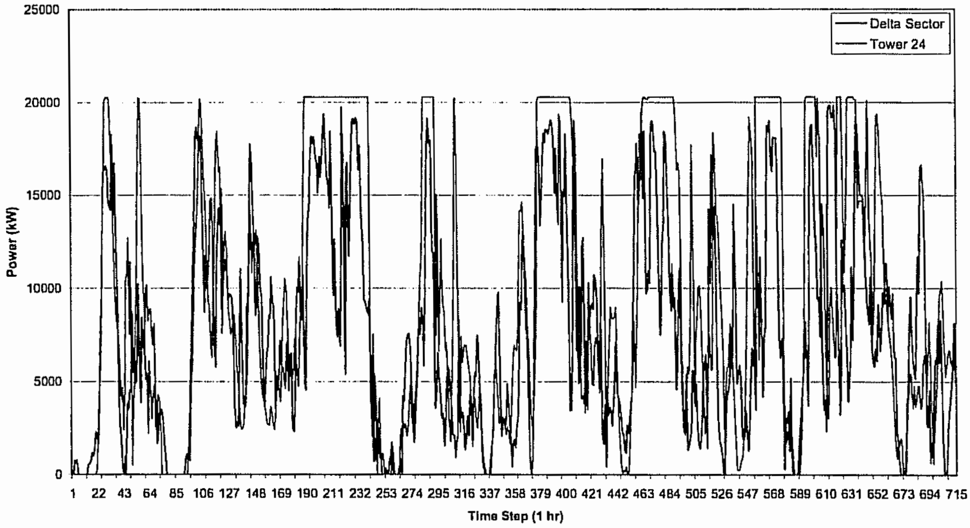


Figure 24: July (top) and August (bottom) power time series for MM5 Tower 24 and the Delta Sector. Mean error (ME), mean absolute error (MAE) and correlation coefficient are shown in the upper right box.

8.86	ME as % of Cap
18.79	MAE as % of Cap
0.68	Correlation



4.79	ME as % of Cap
15.85	MAE as % of Cap
0.79	Correlation

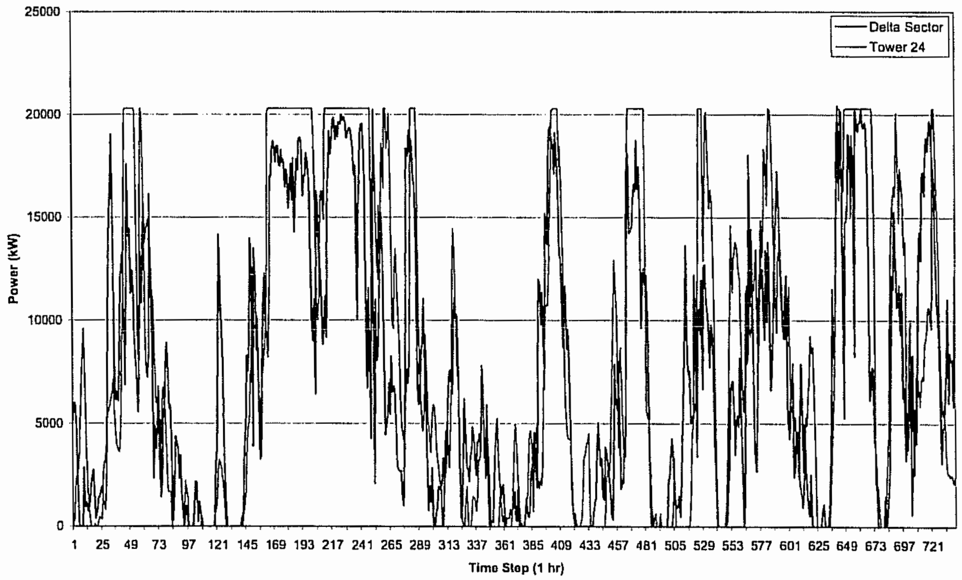
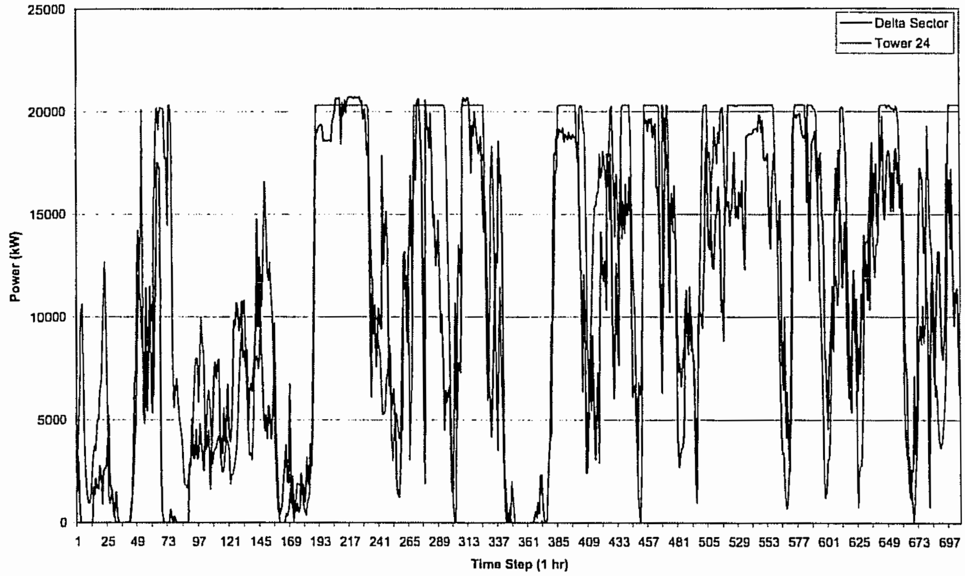


Figure 25: September (top) and October (bottom) power time series for MM5 Tower 24 and the Delta Sector. Mean error (ME), mean absolute error (MAE) and correlation coefficient are shown in the upper right box.

5.56	ME as % of Cap
14.97	MAE as % of Cap
0.79	Correlation



3.85	ME as % of Cap
14.79	MAE as % of Cap
0.78	Correlation

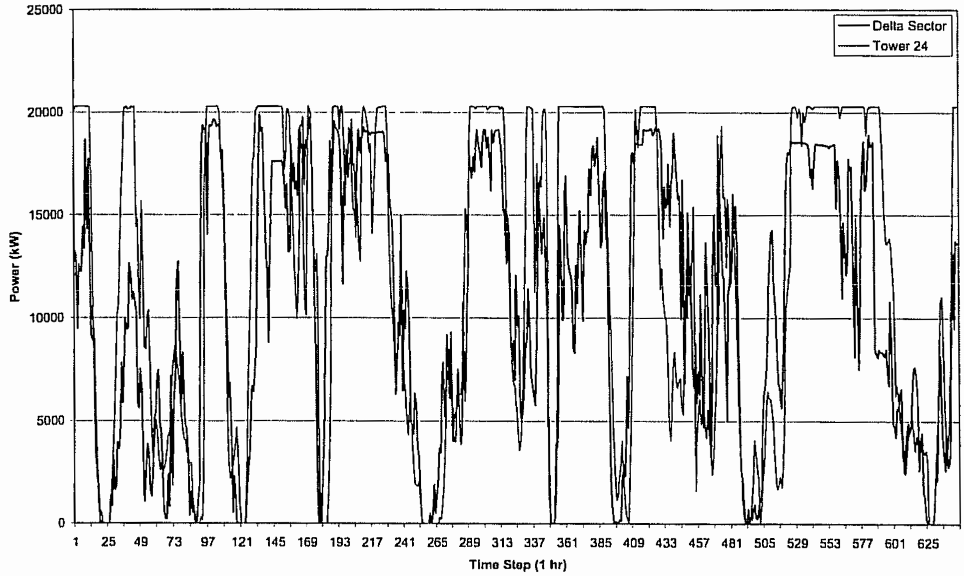


Figure 26: November (top) and December (bottom) power time series for MM5 Tower 24 and the Delta Sector. Mean error (ME), mean absolute error (MAE) and correlation coefficient are shown in the upper right box.

Task 2: Xcel System Model Development

Task Description

a) Data Collection

Collect, review, and verify all necessary data for performing the analysis for at least one calendar year including:

- Historical Xcel North system data (system load, generation, load and generation day ahead forecasts, tie-line interchange, Area Control Error, etc);
- Generator characteristic data for Xcel North and adjacent control areas (type, capacity, minimum generation level, ramping capability, etc);
- Midwest Independent System Operator (MISO) system data and models.

b) Develop System Model for Future Year

Develop projected system data (load growth, generator additions, etc), in coordination with MISO and Xcel Energy, for NSP and directly connected neighboring control areas. Incorporate the models and database developed for the 2003 MISO Transmission Expansion Plan[3].

Wind Generation Scenario

The geographic distribution of the individual wind plants comprising the 1500 MW scenario is a critical element for the study. Discussions with the project sponsors were used to construct the scenario depicted in Figure 27: Wind generation scenario.Figure 27 and listed in Table 6 below.

Table 6: County Totals for 1500 MW of Wind Generation in Study

County	Nameplate Capacity
Lincoln	350 MW
Pipestone	250 MW
Nobles	250 MW
Murray	150 MW
Rock	50 MW
Mower	150 MW
Brookings (SD)	100 MW
Deuel (SD)	100 MW
Grant (SD)	50 MW
Roberts (SD)	50 MW
Total	**1,500 MW**

Xcel's December 19, 2004 filing (Compliance Filing of Wind Accounting as required in MN PUC Docket No. E-002/CN-01-1959) lists individual wind farms which are operational, under construction, signed, or under negotiation totaling approximately 915 MW. Of this 915, about 335 is in Lincoln, 216 is in Pipestone, 66 is in Murray, 200 is in Nobles, 55 is distributed between Redwood, Sibley, Pope, Dodge, and Clay, and 42 is undesignated.

The scenario for the study adds another 500 MW to this total.

[3] MTEP-03, June 2003, http://www.midwestiso.org/plan_inter/documents/expansion_planning/MTEP%202002-2007%20Board%20Approved%20061903.pdf.

The resulting distribution for the wind generation was based on the following criteria:

- Existing installations
- Projects under construction, contract, or negotiation
- Previous project activity that may not necessarily be ongoing at this time. The Mower County location is best example of this – sites within this county have been under discussion in the past, although nothing is planned at this time. This partially explains why this county might appear to be an "outlier" in the overall distribution even though the wind resource appears to be less viable than areas further to the west.
- Probable future developments based on the viability of the wind resource. Projects in eastern South Dakota fall into this category

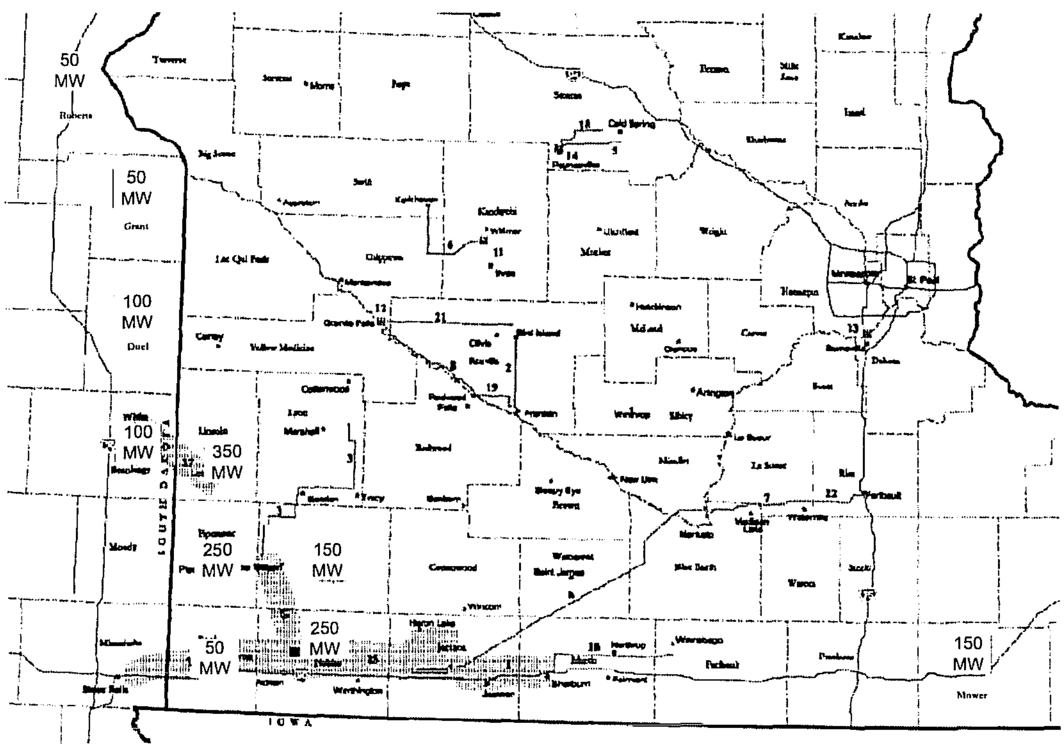


Figure 27: Wind generation scenario.

Turbine Technology and Power Curve Assumptions

The wind generation scenario for the study includes approximately 400 MW of existing wind generation. The remaining 1100 MW is assumed to be coming on line between the date of this study and calendar year 2010. A majority of the existing wind generation is based on the Enron Z750 turbine, a variable-speed predecessor to the commercial flagship turbine from GE Wind, the 1.5s. The power, speed, and torque characteristics of the Z750 are shown in Figure 28.

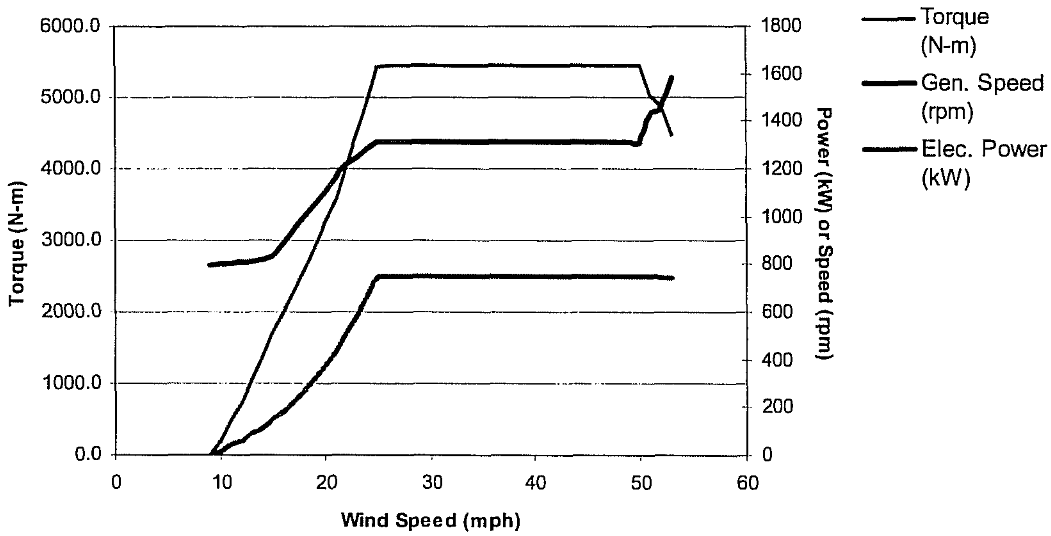


Figure 28: Power, torque, and generator speed relationships for Enron Z50 750 kW wind turbine.

New wind generation projects will employ today's commercial turbine technologies along with anticipate advanced commercial turbines. The power curve selected to represent the near-term commercial wind turbine technology is shown in Figure 29.

Ongoing NREL research is expected to lead to commercial turbine technologies more suited to Class 3 and Class 4 wind sites. The power curve assumed for this technology is shown in Figure 30.

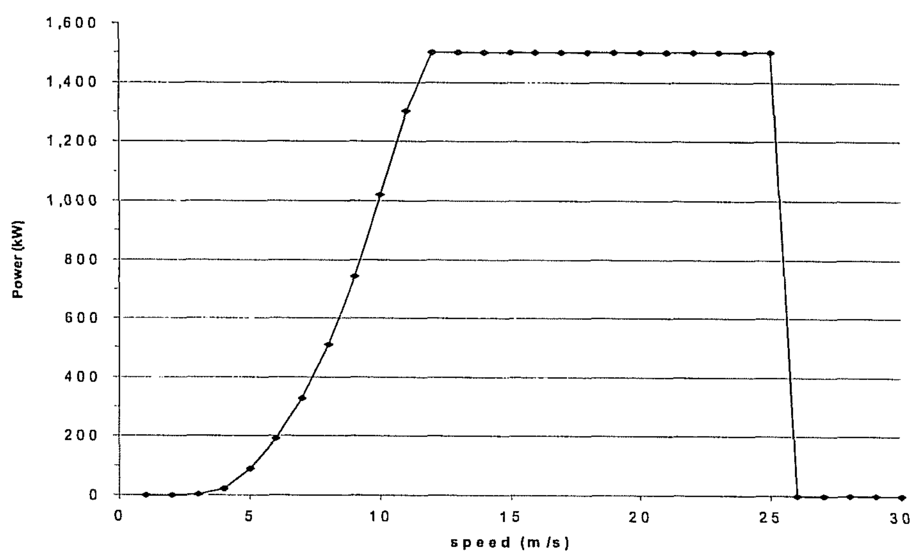


Figure 29: Power curve for new near-term projects in study scenario

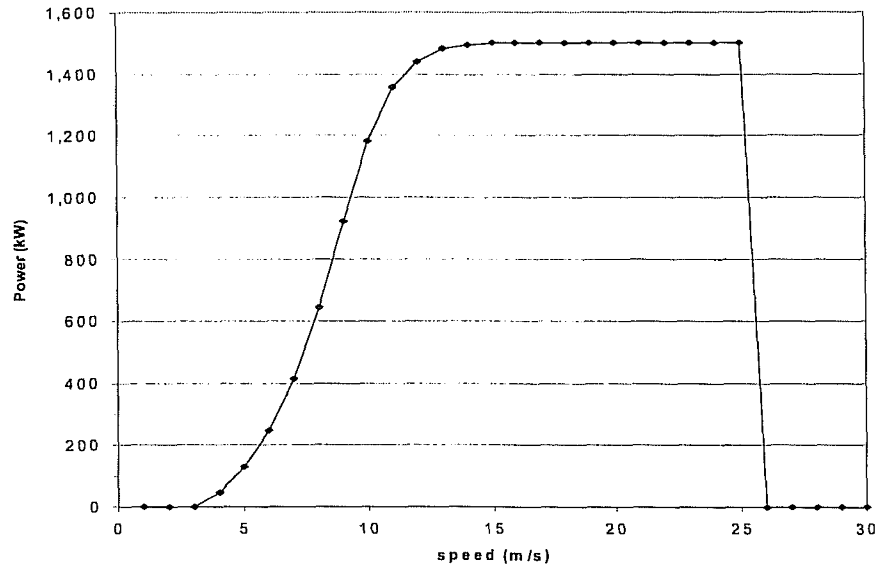


Figure 30: Power curve for longer-term projects in study scenario; meant to serve as a proxy for "low wind speed" turbine technology

Deployment of Turbine Technologies in Study Scenario

Through discussions with the project sponsors, as well as input from the members of the Technical Review Committee, turbine technologies were deployed for new wind generation in the study scenario according to Table 7. Note that counties with new projects have a blend of the two new turbine technologies, reflecting a relatively even development of wind generation up to the study year.

Table 7: Wind Generation by County and Turbine Type

County	2010 Nominal Capacity (MW)	2002 Existing Capacity (MW)	Existing 750 KW Turbines (no.)	Need Capacity (MW)	GE 1.5s Turbines	Capacity (MW)	GE1.5sl Turbines (no.)	Capacity (MW)	Actual Nameplate Capacity (MW)
Lincoln	350	201	268	149	50	75	49	73.5	349.5
Mower	150			150	50	75	50	75.0	150.0
Murray	150			150	50	75	50	75.0	150.0
Nobles	250			250	83	124.5	84	126.0	250.5
Pipestone	250	198	264	52	17	25.5	18	27.0	250.5
Rock	50			50	17	25.5	16	24.0	49.5
Brookings	100			100	33	49.5	34	51.0	100.5
Deuel	100			100	33	49.5	34	51.0	100.5
Grant	50			50	17	25.5	16	24.0	49.5
Roberts	50			50	17	25.5	16	24.0	49.5
TOTAL	1500	399	532	1101	367	550.5	367	550.5	1500.0

Development of Wind Generation Profiles

The wind generation "models" to be used in the analytical tasks consist of chronological series of hourly or ten-minute wind plant production for the years 2000, 2002, and 2003. The wind speed values for each "tower" in the Wind Logics data set were converted to generation in MW by applying the power curves of Figure 28 through Figure 30 according to the "key" in Table 7. Approximate loss factors as discussed in the previous section on model validation were also applied.

Xcel System Model

The Xcel system model consists of generating resources and aggregate load within the control area along with inter-ties to neighboring control areas. Interactions between the Xcel system and prospective MISO markets in 2010 are to be considered. The study scope excludes explicit consideration of the Xcel transmission network and certain issues related to that network such as congestion and dynamic stability.

The basis for the Xcel system model was provided in the form of a projected Load and Resources table for 2010. The breakdown of the supply portfolio by resource type is shown in Table 8 . Figure 31 shows the composition of the portfolio by fuel type.

Table 8: Xcel-North Project Supply Resources for 2010

Resource Type	Capacity (MW)
Existing NSP-owned generation	7,529
Planned NSP-owned generation	773
Long-term firm capacity purchases	903
Other purchase contracts with third-party generators (including wind)	915
Short-term purchases considered as firm resources	1,307
Total	11,426

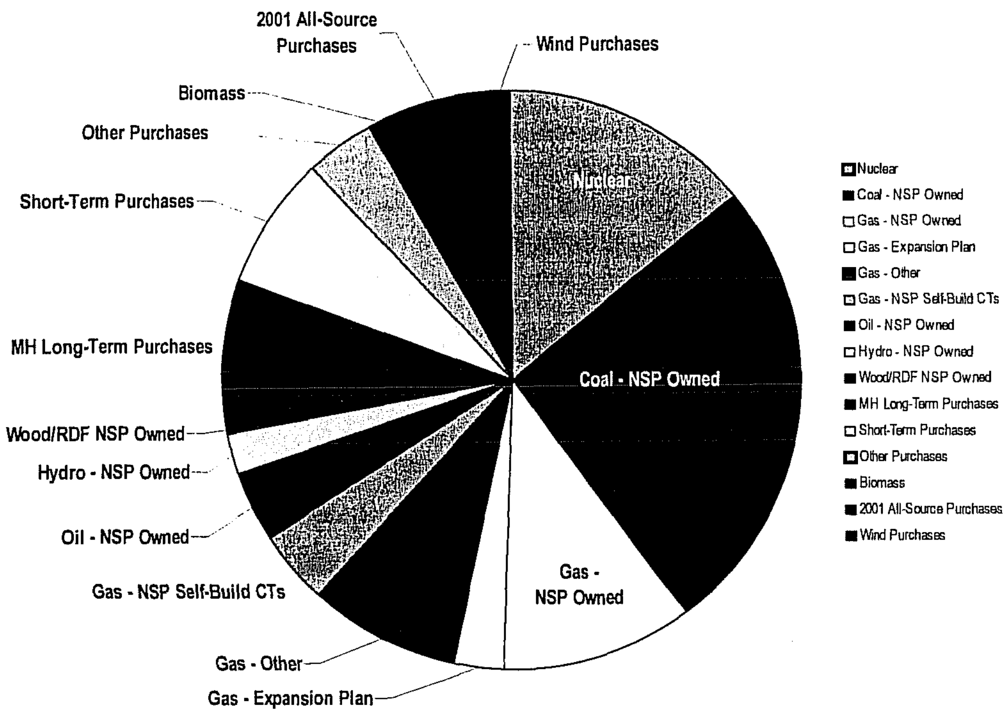


Figure 31: Xcel-North generation resources for 2010 by fuel type.

System load for the 2010 study years was provided as a forecast of the peak hourly load, including the project impacts of DSM (demand-side management) programs. The peak load for 2010 is forecast to be 9933 MW.

For the chronological simulations of both Task 3 and Task 4, hourly system load values for 2010 were generated by scaling Xcel-North load data for the years 2000, 2002, and 2003 so that the peak hour in each year equals the forecasted peak load in 2010. A benefit of this approach is that any correlation between system load and wind speed (or the meteorology that drives the wind speed) is inherently captured. The WindLogics modeling approach results in "actual" wind speed values for the tower sites of interest for those years; the corresponding Xcel system load data for those years then completes the set.

Detailed Model Data

Generating Unit Characterization

The analyses of Tasks 3 and 4 require some fairly specific and detailed data on generating unit characteristics. Information on the existing supply assets was contained in two primary datasets:

- An ABB Couger (unit commitment program used by Xcel for generation scheduling) "saved case", which contains operating and cost information for each generating unit in the Xcel fleet, along with information on purchases and sales as presently conducted;
- The MAPP RCO (Resource Capacity Obligation) data set for GE-MARS (Multi-Area Reliability Simulation), which contains information on generating unit forced outage rates required for the reliability analysis of Task 3.

Historical Performance Data for Xcel-North System

A variety of historical data for the Xcel-North system was also collected.

- 5-min load data for 2002 & 2003
- Total hourly wind generation for 2002 & 2003
- Hourly load data for 1999 through 2003
- Hourly generation data by unit for 2002 & 2003
- Highest resolution load/generation/ACE data (at AGC scan rate – 4 seconds)for two weeks in April, 2004
- High resolution load/generation/ACE data (5 minute) for two weeks in April, 2004

A sample of the high-resolution system load data is shown in Figure 32.

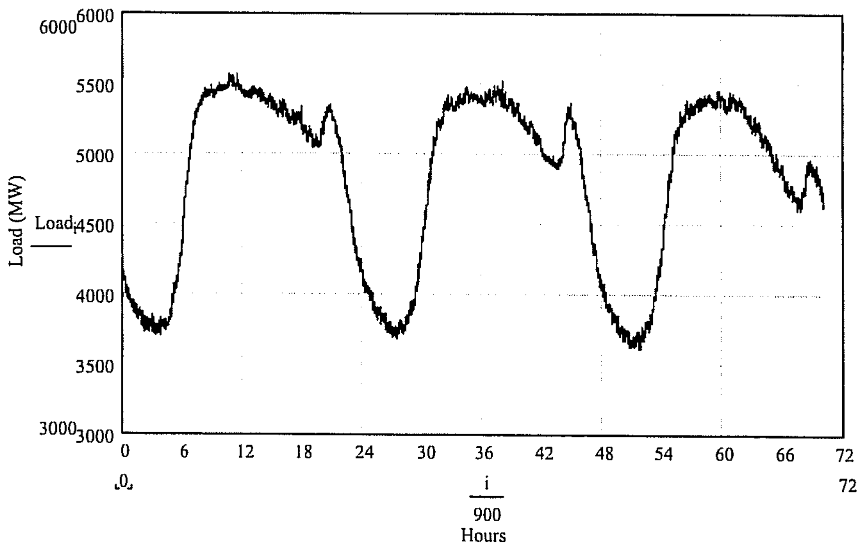


Figure 32: Sample of high-resolution (4 second) load data from Xcel EMS for three days in April, 2004.

The historical data is to be used in a number of ways in later tasks, including:

- Estimating regulating requirements through statistical techniques
- Calculating expected effect on load following requirements and possible changes to operating reserve strategy
- Synthesizing hourly loads for study year

It will also provide a basis for "sanity checking" the models for operational simulations.

Other Data

The 10-minute resolution of the WindLogics dataset is inadequate for fully characterizing the impacts of the 1500 MW of wind generation on the regulation of the control area. To estimate the characteristics of the wind generation in the study scenario, monitoring data from NREL for the Buffalo Ridge substation and Lake Benton II wind plant was obtained. This data consists of

- high-resolution (1 second) measurement data from Buffalo Ridge substation, over 225 MW of wind generation

- NREL high-resolution measurement data from four interconnection points (Delta (30 Z750 turbines), Echo (39 Z750 turbines), Foxtrot (14 Z750 turbines), Golf (55 Z750 turbines)) within the Lake Benton II wind plant (which is also connected to the Buffalo Ridge substation.

A sample of this data for one day in the spring of 2003 is shown in Figure 33.

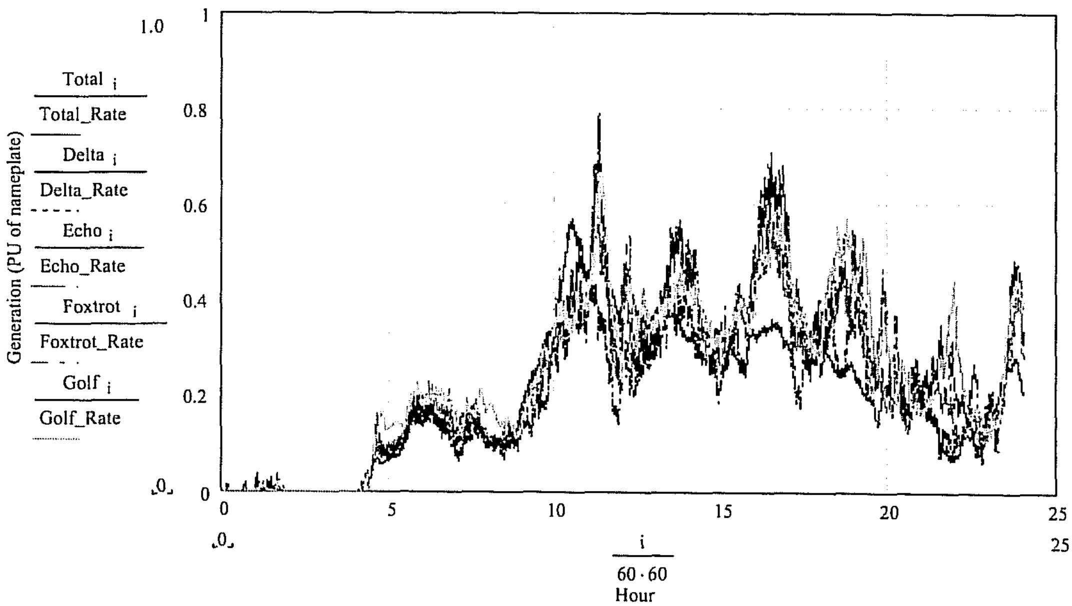


Figure 33: Illustration of High-resolution (1 second) wind plant measurement data from NREL monitoring program.

Task 3: Reliability Impacts of Wind Generation

Task Description

Evaluate the reliability impacts of wind generation in the planning horizon (seasonal, for one year):

- Determine the capacity value of the wind generators by calculating their *effective load carrying capability* (ELCC) to measure the wind plant's capacity contributions based on its influence on overall system reliability. This requires a reliability model that can calculate *loss of load probability* (LOLP) and loss of load expectation (LOLE).
    1) Run a system reliability model with the existing wind generators to determine the existing reliability level using LOLE.
    2) Remove the wind generators from the system and rerun the model to determine the incremental reliability that is provided by the renewable generator.
    3) Return to the configuration of step 1. Incrementally decrease hourly loads and rerun the model until the reliability of the system matches that in step 2.
    4) The reduction in system load in step 3 is the ELCC of the existing wind generators.
    5) Run the system reliability model with 1500 MW of wind generation and repeat the analysis.
- Compare results to the existing MAPP guidelines for establishing capability ratings for variable capacity generation and develop recommendations for improvements to the guidelines.

Description of Modeling Approach

The purpose of the reliably analysis task of this study is to determine the ELCC (Effective Load Carrying Capability) of the proposed wind generation on the XCEL system. This problem was approached by modeling the system in the GE MARS (Multi-Area Reliability Simulation) program, simulating the system with and without the additional wind generation and noting the power delivery levels for the systems at a fixed reliability level. That reliability level is LOLE (Loss of Load Expectation) of 0.1 days per year.

The MARS program uses a sequential Monte Carlo simulation to calculate the reliability indices for a multi-area system by performing an hour by hour simulation. The program calculates generation and load for each hour of the study year, calculating reliability statistics as it goes. The year is simulated with different random forced outages on generation and transmission interfaces until the simulation converges.

In this study three areas are modeled, the XCEL system including all non-wind resources, an area representing Manitoba Hydro purchases and finally and area representing the XCEL wind resources. The wind resources were separated to allow monitoring of hourly generation of the wind plant during the simulations.

The MARS model was developed based upon the 2010 NSP Load Resources table provided by XCEL Energy. In addition, load shape information was based upon 2001 actual hourly load data provided and then scaled to the 2010 adjusted peak load of 9933 MW.

The GE MARS input data file for the MAPP Reserve Capacity Obligation Review study was provided by MAPPCOR to assist in setting up the MARS data file for this study. State transition tables representing forced outage rate information and planned outage rate information for the XCEL resources where extracted from the file where possible. In some cases it was difficult to map resources from the MAPP MARS file to the Load/Resourses table provided by XCEL. In those cases the resource was modeled using a generic forced outage rate for the appropriate type of generation (steam, combustion turbine, etc) obtained from the MAPP data file.

The model used multiple levels of wind output and probabilities, based on the multiple block capacities and outage rules that can be specified for thermal resources in MARS. In each Monte Carlo simulation, the MARS program randomly selects the transition states that are used for the simulation.

These states can change on and hour by hour basis and thus is suitable for the modeling of the wind resources.

To find a suitable transition rate matrix, 3 years of wind generation data supplied by WindLogics was analyzed. That data was mapped on the proposed system and an hour by hour estimate of generation was calculated for the three years. The generation was analyzed and state transitions were calculated to form the state transition matrix for input to MARS.

Model Assumptions

This section describes assumptions that were made in developing the MARS reliability model for analysis of the XCEL wind plant additions.

The resources are divided into five groups:

- Non-wind Units Mapped to the MAPP MARS file
- Non-wind Units Not Mapped to the MAPP MARS file
- Manitoba Hydro Firm Contract Purchases
- Other Purchases
- Wind Resources

Non-wind Units mapped to MARS data file

Units that could be identified in the MAPP MARS data file where extracted and used with the capacity numbers supplied in the 2010 NSP Load/Resources table. State transition rate matrices and planned outage rates from the MAPP study were used.

Non-wind Units not mapped to MARS data file

A number of units could not be mapped to the MAPP MARS data file. For those units, MARS resources were developed and "generic" attributes assigned to them. The generic attributes were based on the type of resource (steam, combustion turbine, etc). The FOR and planned outage schedules for the various types of resource were selected in the MAPP MARS data file through comments supplied by the maintainers of the data.

The WISCROR hydro plant was modeled as an energy limited resource with capacity of 249 MW, 50% CF year round and a generic 2 state transition matrix for hydro facilities derived from the MAPP database.

Manitoba Hydro Firm Contract Purchases

Purchase from Manitoba Hydro modeled as firm contracts, 5x16. Manitoba Hydro modeled as a separate control area with in the same pool as XCEL. The FOR tables (transition rate matrices) and capacity tables for the Manitoba Hydro to XCEL areas came directly from the MAPP data file. For the interface purposes of this study, the MAPP Minnesota area mapped to the XCEL area. The data is shown below for the interface:

Capacity States:

```
MH-XC          1.0000   0.7610   0.1403   0.0000
```

Transition Rate Matrix (row number correspond to current or "from" state; column numbers are "to" state, with probability of that transition indicated by the table entry)

```
     MH-XC    4   1    0.0000000000    0.0004697800    0.0003523350    0.0000083889
+                 2    0.0241684157    0.0000000000    0.0000000000    0.0000000000
+                 3    0.0358152954    0.0000000000    0.0000000000    0.0000000000
```

+ 4 0.0000000000 6.6666666667 0.0000000000 0.0000000000

The contract was set up as firm 903 MW on 5x16 basis, year round.

Transition rate matrices describe the probability of going from any state to any other state that is defined for the resource. The 6.666667 entry is a special flag that was not documented by GE. The data is copied, verbatim, from the MAPP MARS data file.

Other Purchases

Other purchases in the Load Resource table were modeled as generation with a FOR based on generic transition matrices for small steam plants.

Wind Resources

The following table shows the allocation for wind resources by county. 400 MW of existing wind resources were allocated evenly to Lincoln and Pipestone counties. The remaining 1100 MW of potential capacity were allocated as specified for this study. County allocations were divided evenly to be installed as GE 1.5s turbine and GE 1.5sl low wind speed turbine.

Table 9: Wind Generation by County and Turbine Type

County	2010 Nominal Capacity (MW)	2002 Existing Capacity (MW)	Existing 750 KW Turbines (no.)	Need Capacity (MW)	GE 1.5s Turbines	Capacity (MW)	GE1.5sl Turbines (no.)	Capacity (MW)	Actual Nameplate Capacity (MW)
Lincoln	350	201	268	149	50	75	49	73.5	349.5
Mower	150			150	50	75	50	75.0	150.0
Murray	150			150	50	75	50	75.0	150.0
Nobles	250			250	83	124.5	84	126.0	250.5
Pipestone	250	198	264	52	17	25.5	18	27.0	250.5
Rock	50			50	17	25.5	16	24.0	49.5
Brookings	100			100	33	49.5	34	51.0	100.5
Deuel	100			100	33	49.5	34	51.0	100.5
Grant	50			50	17	25.5	16	24.0	49.5
Roberts	50			50	17	25.5	16	24.0	49.5
TOTAL	1500	399	532	1101	367	550.5	367	550.5	1500.0

These values were used to scale the wind generation data provided by WindLogics and aggregated to provide system wide wind generation over three "normalized" years. This data is described in detail in other sections of this report. The data was conditioned to insure all hours of the years were present. Where a few gaps in the data occurred, the conservative approach was taken and 0 MW generation was assumed. Once the hour by hour wind generation data was obtained, the hourly data was processed to obtain state transition information.

Wind resources were modeled based on a 10 state transition rate matrix. This is the maximum allowable number of states by MARS. The bins were based on 10 even bins from 0 to maximum generation after array and collector system loss factor of 0.86 was applied. The effect of losses was modeled in the MARS simulation by derating the capacity of the generation to 86% of nameplate.

Several parametric analyses were performed to ascertain the sensitivity of the solution to various model parameters. It was determined that modeling the wind resources as a single lumped model provided a slightly pessimistic result (lower LOLE) as apposed to modeling each county individually. This result is consistent with the idea that the larger number of smaller non-dependant plants the lower the overall FOR would be.

The effect of seasonal variation in wind data was also considered. The results show that there was a minimal effect on the LOLE and thus ELCC between the seasonal model and the lumped "all-year" model. The seasonal model was created by processing the generation data into four seasons.

Table 10: Seasonal Definitions for Wind Generation Model

Winter:	December – February
Spring:	March – May
Summer:	June – August
Autumn:	September - November

The state transition matrix was generated for each season and the generation was phased in and out during the modeled year by making the "plant" corresponding to the seasonal state transition matrix available only during that particular season.

Additional cases were run to investigate diurnal effects of the wind on the results.

The results of this analysis are presented in the next section.

Results

Essential results of the study are shown graphically in Figure 34. The plot shows the LOLE for a series of peak load levels for various cases. A description of the cases is found in Table 11.:

Table 11: MARS Case List and Descriptions

Case	Description
Base	No Wind Generation
1	1500 MW Wind Model, no seasonal or diurnal effects
2	1500 MW Wind, Seasonal model, no diurnal effects
3	1500 MW Wind, Summer wind data only, no diurnal effects
4	400 MW Wind (approximate existing turbine capacity) no seasonal , no diurnal
5	Wind Generation as deterministic load modifier

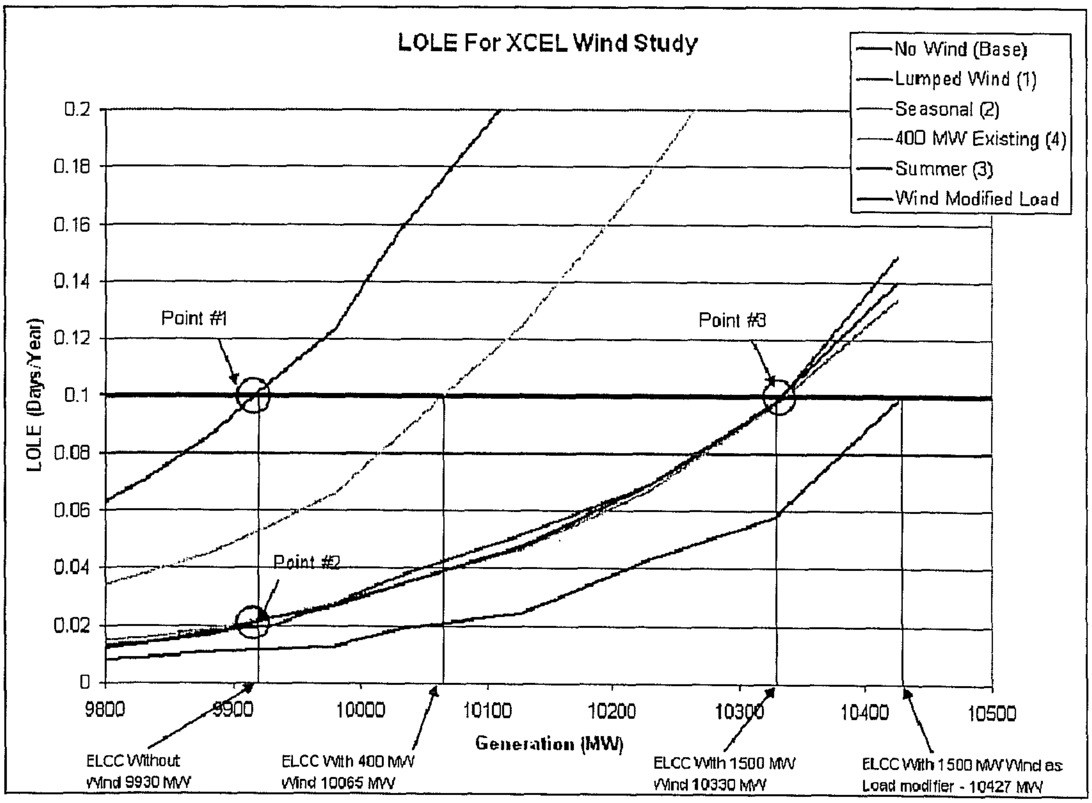


Figure 34: LOLE and ELCC results

Table 12 contains a numeric summary of the results. This table shows that the ELCC of the system improves by 400 MW or 26.67% of nameplate with the addition of 1500 MW of wind resource. The existing 400 MW improved the ELCC by 135 MW or about 33.75%. This is an estimate as the nameplate of the existing wind resource was not known precisely.

Table 12: ELCC Calculation Results

Case	Case Name	ELCC (MW)	ELCC Improvement	
			MW	%Nameplate
1	Lumped Wind	10330	400	26.7%
2	Seasonal	10330	400	26.7%
3	Summer	10330	400	26.7%
4	400 MW Existing	10065	135	33.8%
5	Wind as Load Modifier	10427	493	32.9%

The results show that the summertime wind conditions are dominating the LOLE changes of the wind plants. This is evidenced by the fact that the lumped wind (case 1), seasonal (case 2) and summer (case 3) all yield the same results. This leads to the further conclusion that the ELCC improvement is dependent on the hours modeled. Due to limitations of the MARS program, it is not possible to find the exact hours where LOLE is affected by the wind plant in the simulations, only weekly summary information is available. Thus, it is difficult to tell if the hours of wind data selected are aligning with hours of highest LOLE.

Wind is treated as a load modifier in Case 5. Here, hourly wind generation is subtracted from hourly load for each hour of the annual data set. The results are compared to the case without wind generation. The higher capacity value apparently results from wind generation reducing load in some of the high risk hours, combined with the fact that the contribution is being made for each replication of the year, since wind generation is not being treated probabilistically in this case.

In order to ensure that the ELCC is not affected by planned outages, the monthly and weekly contributions to the LOLE were observed. The following table shows a sample of this data for the base case with no wind and another with 1500 MW of wind generation represented as a lumped model. The effect of the wind generation on system reliability is apparent in Weeks 26, 27, and 31, which for the case without wind generation shows a non-zero LOLE for this peak load level. With wind generation added to the case, the LOLE during those weeks is reduced to zero.

Table 13: GE-MARS results by week

Point #1 - No Wind at peak load of 9930 MW (Base Case)

CALCULATED INDICES FOR 2010

AREA OR POOL	ISOLATED LOLE (days/yr)	ISOLATED LOLE (hrs/yr)	ISOLATED LOEE (MWh/yr)	ISOLATED FREQUENCY (outg/yr)	ISOLATED DURATION (hrs/outg)	INTERCONNECTED LOLE (days/yr)	INTERCONNECTED LOLE (hrs/yr)	INTERCONNECTED LOEE (MWh/yr)	INTERCONNECTED FREQUENCY (outg/yr)	INTERCONNECTED DURATION (hrs/outg)
XCEL	0.115	0.505	115.4	0.181	2.790	0.111	0.459	106.7	0.144	3.188

WEEKLY INDICES FOR XCEL FOR 2010
ON AN INTERCONNECTED BASIS

WEEK	LOLE (days)	LOLE (hours)	LOEE (MWh)	WEEK	LOLE (days)	LOLE (hours)	LOEE (MWh)
1	0.000	0.000	0.000	28	0.000	0.000	0.000
2	0.000	0.000	0.000	29	0.000	0.000	0.000
3	0.000	0.000	0.000	30	0.000	0.000	0.000
4	0.000	0.000	0.000	31	0.002	0.008	2.046
5	0.000	0.000	0.000	32	0.000	0.000	0.000
6	0.000	0.000	0.000	33	0.010	0.037	7.121
7	0.000	0.000	0.000	34	0.082	0.350	79.773
8	0.000	0.000	0.000	35	0.014	0.061	17.398
9	0.000	0.000	0.000	36	0.000	0.000	0.000
10	0.000	0.000	0.000	37	0.000	0.000	0.000
11	0.000	0.000	0.000	38	0.000	0.000	0.000
12	0.000	0.000	0.000	39	0.000	0.000	0.000
13	0.000	0.000	0.000	40	0.000	0.000	0.000
14	0.000	0.000	0.000	41	0.000	0.000	0.000
15	0.000	0.000	0.000	42	0.000	0.000	0.000
16	0.000	0.000	0.000	43	0.000	0.000	0.000
17	0.000	0.000	0.000	44	0.000	0.000	0.000
18	0.000	0.000	0.000	45	0.000	0.000	0.000
19	0.000	0.000	0.000	46	0.000	0.000	0.000
20	0.000	0.000	0.000	47	0.000	0.000	0.000
21	0.000	0.000	0.000	48	0.000	0.000	0.000
22	0.000	0.000	0.000	49	0.000	0.000	0.000
23	0.000	0.000	0.000	50	0.000	0.000	0.000
24	0.000	0.000	0.000	51	0.000	0.000	0.000
25	0.000	0.000	0.000	52	0.000	0.000	0.000
26	0.001	0.002	0.287	53	0.000	0.000	0.000
27	0.001	0.002	0.050				

Point #1 - 1500 MW Wind Generation (Lumped Model) with peak load of 9930 MW (Base Case)

CALCULATED INDICES FOR 2010

AREA OR POOL	ISOLATED LOLE (days/yr)	ISOLATED LOLE (hrs/yr)	ISOLATED LOEE (MWh/yr)	ISOLATED FREQUENCY (outg/yr)	ISOLATED DURATION (hrs/outg)	INTERCONNECTED LOLE (days/yr)	INTERCONNECTED LOLE (hrs/yr)	INTERCONNECTED LOEE (MWh/yr)	INTERCONNECTED FREQUENCY (outg/yr)	INTERCONNECTED DURATION (hrs/outg)
XCEL	0.022	0.108	25.7	0.039	2.769	0.022	0.100	24.1	0.032	3.109

WEEKLY INDICES FOR XCEL FOR 2010
ON AN INTERCONNECTED BASIS

WEEK	LOLE (days)	LOLE (hours)	LOEE (MWh)	WEEK	LOLE (days)	LOLE (hours)	LOEE (MWh)
1	0.000	0.000	0.000	28	0.000	0.000	0.000
2	0.000	0.000	0.000	29	0.000	0.000	0.000
3	0.000	0.000	0.000	30	0.000	0.000	0.000
4	0.000	0.000	0.000	31	0.000	0.000	0.000
5	0.000	0.000	0.000	32	0.000	0.000	0.000
6	0.000	0.000	0.000	33	0.003	0.013	1.792
7	0.000	0.000	0.000	34	0.016	0.072	18.153
8	0.000	0.000	0.000	35	0.003	0.014	4.122
9	0.000	0.000	0.000	36	0.000	0.000	0.000
10	0.000	0.000	0.000	37	0.000	0.000	0.000
11	0.000	0.000	0.000	38	0.000	0.000	0.000
12	0.000	0.000	0.000	39	0.000	0.000	0.000
13	0.000	0.000	0.000	40	0.000	0.000	0.000
14	0.000	0.000	0.000	41	0.000	0.000	0.000
15	0.000	0.000	0.000	42	0.000	0.000	0.000
16	0.000	0.000	0.000	43	0.000	0.000	0.000
17	0.000	0.000	0.000	44	0.000	0.000	0.000
18	0.000	0.000	0.000	45	0.000	0.000	0.000
19	0.000	0.000	0.000	46	0.000	0.000	0.000
20	0.000	0.000	0.000	47	0.000	0.000	0.000
21	0.000	0.000	0.000	48	0.000	0.000	0.000
22	0.000	0.000	0.000	49	0.000	0.000	0.000
23	0.000	0.000	0.000	50	0.000	0.000	0.000
24	0.000	0.000	0.000	51	0.000	0.000	0.000
25	0.000	0.000	0.000	52	0.000	0.000	0.000
26	0.000	0.000	0.000	53	0.000	0.000	0.000
27	0.000	0.000	0.000				

With wind generation in the case, all LOLE days occur in August when no planned outages are scheduled. An example of the planned outage information can be found in the appendices.

Table 14 shows the data for the LOLE plots in Figure 34.

Table 14: Source Data for LOLE Curves of Figure 34

Peak Load (pu)	Peak Load (MW)	No Wind LOLE	Lumped Wind LOLE	Seasonal Model LOLE	400 MW Existing Wind	Noon To 6	Summer Daylight	Summer
1.04	10327	0.394	0.097	0.097	0.238	0.338	0.241	0.101
1.03	10228	0.287	0.069	0.067	0.177	0.245	0.174	0.069
1.02	10129	0.21	0.052	0.047	0.125	0.179	0.124	0.048
1.01	10029	0.157	0.037	0.034	0.086	0.128	0.087	0.034
1.005	9980	0.123	0.028	0.028	0.066	0.101	0.071	0.027
1	9930	0.105	0.02	0.023	0.055	0.083	0.056	0.023
0.995	9880	0.086	0.018	0.019	0.045	0.072	0.046	0.017
0.99	9831	0.071	0.014	0.016	0.038	0.063	0.035	0.014
0.98	9731	0.046	0.012	0.013	0.026	0.041	0.021	0.009
0.97	9632	0.031	0.004	0.007	0.017	0.024	0.014	0.007

The following plot shows the contributions that each county makes to the overall improvement of LOLE across the system. Included on the plot are the "no-wind" case, existing wind resources and full wind results.

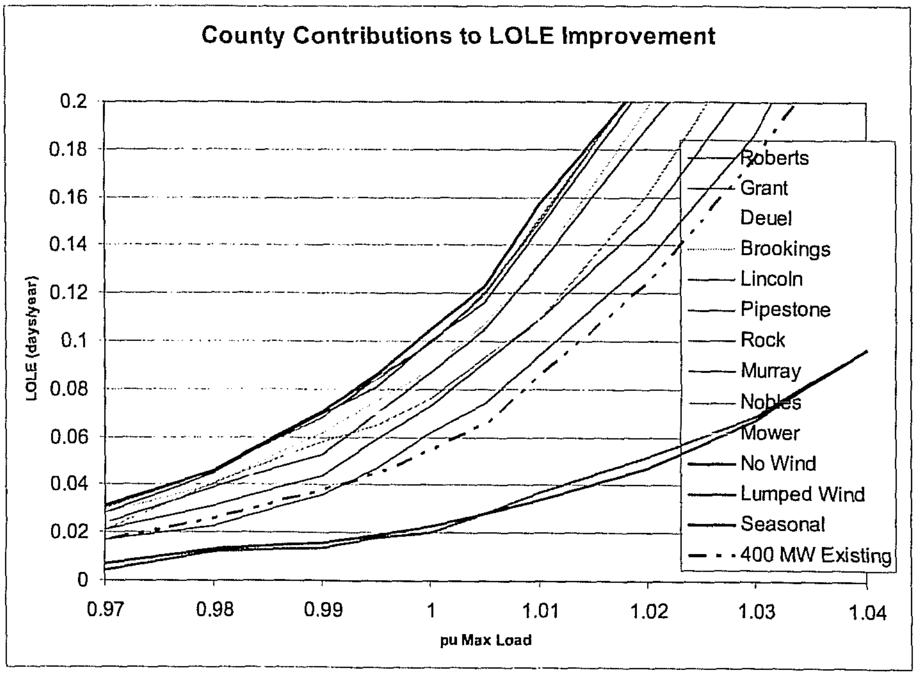


Figure 35: Effects of wind generation by county on LOLE.

The plots in Figure 36 illustrate typical wind generation profiles synthesized for the "replications" or Monte Carlo iterations in GE-MARS. A replication is a single "roll of the dice" for the system and thus a full solution to a random set of conditions. This data was obtained by modeling the wind resources in a separate area and requesting that MARS provide hourly flows across an area interface. Each and every replication would yield a different characteristic as forced outage transitions are randomized. Twenty-five (25) replications were analyzed to validate the actions of the MARS calculations. The number of hours spent at maximum output was determined for each of the replications. The average value was 850 hours per year, minimum was about 250 hours and maximum was about 1800 hours. Determining the "typical" replication was a qualitative effort to find the average "time at max output" replication.

Note that the discretization of the time series due to the eleven state limitation in GE-MARS is evident. The effect on the LOLE plots, however, is much less evident, as most of the curves in Figure 34 and Figure 35 are relatively smooth.

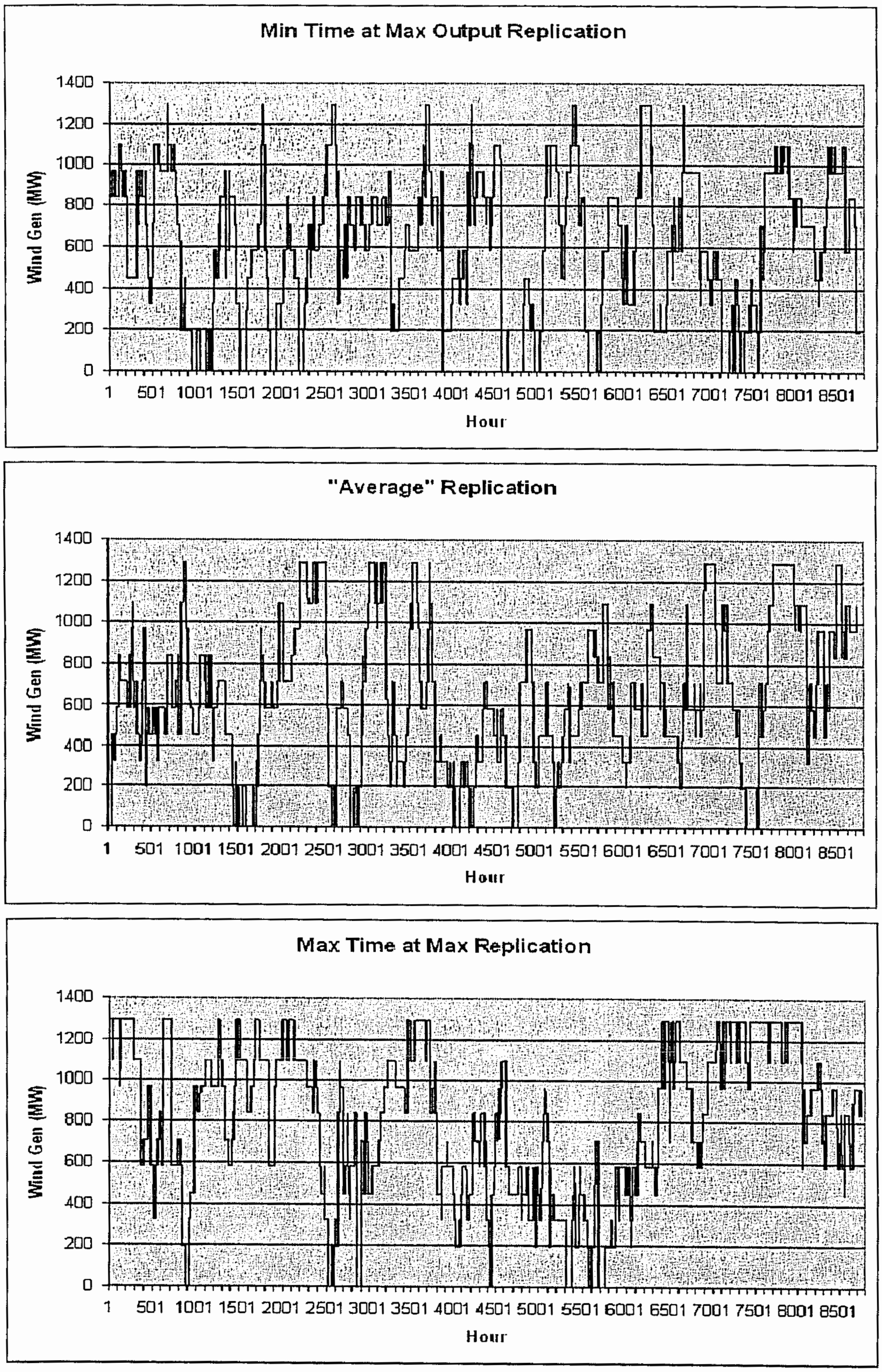


Figure 36: Sample wind generation time series generated by GE-MARS

Results of MAPP Accreditation Procedure for Variable Capacity Generation

The MAPP procedure for accreditation of variable capacity generation was applied to the aggregate wind generation data for the three years contained in the data set. Results are shown in Table 15. For the peak month of July, the accredited capacity of the aggregate wind generation is 249 MW. Using a 1500 MW nameplate rating, the normalized accredited capacity would be 17%.

Table 15: Monthly accreditation of aggregate wind generation in study scenario per MAPP procedure for variable capacity generation

Month	Median (MW)	%
January	394	26.3%
February	498	33.2%
March	285	19.0%
April	370	24.7%
May	423	28.2%
June	334	22.3%
July	249	16.6%
August	293	19.5%
September	492	32.8%
October	376	25.1%
November	499	33.3%
December	444	29.6%
AVERAGE	388	25.9%

For comparison, the MAPP algorithm was applied to historical wind generation data provided by Xcel Energy for the same three years. These results are shown in Table 16. The normalized accredited capacity for what amounts to a single wind plant for the peak month of July is just over 13%. (The assumed nameplate rating for the "wind plant" in the historical data was assumed to be 300 MW, since this is the maximum hourly generation value that appears in the data set).

Table 16: Monthly accreditation of Buffalo Ridge wind generation using MAPP procedure for variable capacity generation.

Month	Median (MW)	%
January	62	20.7%
February	112	37.3%
March	87	29.0%
April	90	30.0%
May	61	20.3%
June	63	21.0%
July	40	13.3%
August	39	13.0%
September	114	38.0%
October	86	28.7%
November	120	40.0%
December	122	40.7%
AVERAGE	83	27.7%

Observations

As evidenced by Table 12, the reliability contribution of wind generation to the Xcel control area depends on the data used for developing the wind generation model – a conclusion reached sometime ago by Milligan based on work in [7], [8], [10], [13], [14] .

The results fall into the range of what would be "expected" by researchers and others familiar with modeling wind in utility reliability models. A remaining question, then, is one of the differences between the formal reliability calculation and the capacity accreditation procedure currently used in MAPP and being contemplated by other organizations.

The MAPP procedure takes the narrowest view of the historical production data by limiting it to only those hours around the peak hour for the entire month, which potentially excludes some hours where the load is still substantial and there would be a higher risk of outage. Applying the MAPP procedure to the aggregate wind generation model developed for this study yields a minimum capacity factor of about 17%. It is still smaller, however, than the ELCC computed using lumped or seasonal wind models (26.7%).

Even though the formal reliability calculation using GE-MARS utilizes a very large number of "trials" (replications) in determining the ELCC for wind generation, the wind model in each of those trials is still based on probabilities and state transition matrices derived from just three years of data. Some part of the difference between the MAPP method and the formal reliability calculation, therefore, can be attributed to an insufficient data set for characterizing the wind generation. When the sample of historical data is augmented to the ten year historical record prescribed in the MAPP method, the capacity value determined by the MAPP method would likely increase, reducing the magnitude of the difference between the two results.

This does not account for the entire difference between the methods, though. The MAPP procedure only considers the monthly peak hour, so the seasonal and diurnal wind generation variations as characterized in Task 1 of this project would lead to a discounting of its capacity value.

It is interesting to note that the average of the monthly capacity accreditation values determined by the MAPP method is very close to the result from the formal reliability calculation. This appears to be an anomaly or coincidence, however, since the mathematical machinery used in the two calculations is completely different. Additionally, the results of the GE-MARS replications show that the contributions made by wind generation to system ELCC are confined to the summer peak months.

Recommendations

There are clear differences between the MAPP Capacity Credit method and the ELCC approach used in this study. The MAPP algorithm selects wind generation data from a 4-hour window that includes the peak, and is applied on a monthly basis. The ELCC approach is a risk-based method that quantifies the system risk of meeting peak load, and is primarily applied on an annual basis. ELCC effectively weights peak hours more than off-peak hours, so that two hypothetical wind plants with the same capacity factor during peak hours can receive different capacity ratings. In a case like this, the plant that delivers more output during high risk periods would receive a higher capacity rating than a plant that delivers less output during high risk periods.

The MAPP approach shares a fundamental weakness with the method adopted by PJM: the 4-hour window may miss load-hours that have significant risk, therefore ignoring an important potential contribution from an intermittent generator. Conversely, an intermittent generator may receive a capacity value that is unjustifiably high because its generation in a high-risk hour is lower than during the 4-hour window.

Because ELCC is a relatively complex, data-intensive calculation, simplified methods could be developed at several alternative levels of detail. Any of these approaches would fully capture the system's high-risk hours, improving the algorithm beyond what would be capable with the fixed, narrow window in the current MAPP method. Any of the methods outlined below can also be applied to several years of data, which could be made consistent with current MAPP practice of using up to 10 years of data, if available. These methods are briefly outlined below.

1. Annual capacity credit: Calculate the capacity factor for the intermittent resource over the top 10% of annual load-hours. This approach was suggested by Milligan & Parsons, 1997.
2. Application of (1) to seasonal capacity value: Calculate the capacity factor for the intermittent resource over the top 10% of seasonal load-hours. Carry out this calculation separately for each season.
3. Application of (1) and (2) to monthly capacity value: Calculate the capacity factor for the intermittent resource over the top 10% of monthly load-hours. Carry out this calculation separately for each month. (Note that the annual capacity credit is not the lowest of the 12 monthly values; rather, it is calculated as specified in (1) above.
4. Garver's approximation [16] for annual capacity credit. The Garver approach was first proposed in an IEEE article in the 1960's, and can be extended to intermittent generators such as wind. The approach approximates the declining exponential risk function (LOLP in each hour, LOLE over a high-risk period). It requires a single reliability model run to collect data to estimate Garver's constant, known as m. Once this is done, the relative risk for an hour is calculated by

$$R' = \mathrm{Exp}\{-[(P-L)/m]\}$$

   P = annual peak load, L = load for the hour in question. R' is the risk approximation (LOLP), measured in relative terms (peak hour risk = 1).

Construct a spreadsheet that calculates R' for the top loads. Then modify the values of L by subtracting the wind generation in that hour.

Calculate LOLE approximation for (a) no-wind case and (b) wind case by summing the hours. Use all hours for which no-wind risk exceeds some tolerance – probably around 500 hours. Compare to gas plant or other benchmark, de-rated by its forced outage rate.

5. Seasonal application of the Garver approximation could be carried out by calculating the relative risk in the same manner as in (4), but applied to seasonal loads.
6. Monthly application of the Garver approximation could be carried out by calculating the relative risk in the same manner as in (4), but applied to monthly loads.

A hybrid approach to capacity valuation could also be adopted. For example, a series of reliability runs could be made to determine the high-risk hours of each month, season, or year. Several years could be analyzed in this way. Based on the results, a time window could be chosen that represents the likely high-risk hours to the system (relatively high LOLP). These periods could then be used to calculate the capacity value of wind, by using the capacity factor during that time period.

Task 4: Evaluate Wind Integration Operating Cost Impacts

Task Description

Evaluate the additional operating cost impact of the variability and the uncertainty of the wind generation including regulation, load following, and unit commitment. The costs will be evaluated for 1500 MW of wind power delivered to NSP customer load for the projected 2010 system (load, generation, etc) while dispatching regional generation that is not electrically constrained.

The evaluation will recognize and build upon previous studies and include an updated unit commitment model, improved ability to forecast wind, netting with load forecast errors, geographic diversity in the wind plants, and the regional grid and developing markets. Consideration should be given to both actual cost of service impacts and to projected market prices for ancillary services. The evaluation should identify and examine the impacts of key market-based and penalty-based methods for dealing with the operating impacts.

The evaluation will be conducted for the following time horizons:

<u>Regulation:</u> Evaluate the regulation requirement in the Automatic Generation Control time horizon (several seconds to 10 minutes) associated with wind generation variability.

Determine the additional regulation requirement in the time frame of AGC cycle for supporting wind plant integration using the methodology developed by Oak Ridge National Laboratory (This method was used in the first wind plant impact study for Xcel North.) In this approach, the high frequency component is extracted from the high-resolution historical data separately for system load and wind generation.

<u>Load Following:</u> Evaluate the reserve requirements in the load following time horizon (10 minutes to several hours) associated with wind generation variability.

- Determine the intra-hour impacts to reserve capacity requirements within the hour, in 5 to 10 minute increments, associated with wind generation variability.
- Determine the energy impacts of following the ramping and fluctuation of the wind generation in the load following time horizon.

<u>Unit Commitment:</u> Evaluate the regulation requirement in the unit-commitment time horizon (several hours to several days) associated with wind generation variability.

- Determine the cost incurred to re-schedule units because of inaccuracy associated with the wind generation forecasts (netted with load forecast errors), in the day-ahead scheduling.

Calculation of Incremental Regulation Requirements

The net load in a utility control area varies continuously over a wide spectrum of time scales, from seasons to seconds. Electric energy supply must be adjusted on a continuous basis to meet this demand while maintaining system security and honoring transaction agreements with other control areas. "Control" of the system requires that generating units be deployed according to their costs and physical capabilities to achieve this balance in real time.

Regulation - Background

In the context of this study, regulation is defined as the process of adjusting generation in response to the fastest fluctuations or variations in the control area load. In characterizing the time scale for this regulation function, it is helpful to consider the infrastructure that is employed for making these adjustments. An Energy Management System, or EMS, is a wide-area control system that (in simple terms):

- Periodically receives data from a large number of measurement points regarding the "state" of the power system under its auspices including real power, voltage, reactive power, device status, etc.;
- executes algorithms to determine how the system is performing at that instant and possibly to forecast conditions that will need to be met in the moments ahead;
- sends signals to certain generating units to raise or lower their output to correct imbalance between supply and demand in the control area.

Automatic Generation Control (AGC) is a subsystem of the EMS that has the following functions and responsibilities:

- adjusting generation to hold system frequency at or close to the nominal value of 60 Hz for North American power systems;
- maintaining the correct value of power imports and exports with other control areas;
- ensuring that the output of each generator under its control results in lowest possible production cost.

The speed at which this closed-loop control system acts can be no faster than the rate at which new information is input to the control algorithms. This is sometimes referred to as the "scan rate." In most systems, new information on the state of the system is obtained every few seconds. For the Xcel-NSP EMS, the scan rate is 4 seconds.

AGC operates without human intervention, and therefore is well-suited to making fast and continuous adjustments to generation to achieve the desired system performance. Because control actions are not "free", the rate at which generation adjustments are made will be much slower than the rate at which new system state information is provided to the EMS and AGC subsystem, yet still faster than a scheme with human intervention would allow.

The moment-to-moment fluctuations in net control area demand that give rise to the need for fast generation control actions are the consequence of the combined actions of all users of electric energy. These fluctuations differ from the longer-term (i.e. hour to hour) trends in the system load which are indicative of daily customer usage patterns and other electric demand drivers such as type of day, weather, etc. The temporal boundary between load variations that require regulation service for compensation and those that would be considered as actual load trends is somewhat subjective. Specifying a boundary where the regulation variations are roughly symmetrical about the underlying trend characteristic - i.e. the integrated energy of the regulation characteristic over a longer period is zero - seems convenient from the perspective of generation control. Units assigned regulation responsibility must reserve capacity (or operate at some margin above minimum load) for equal upward and downward movements over short periods of time; if the net energy delivered while providing regulation is zero, this function can be characterized as impacting only capacity.

This characterization of the appropriate temporal boundary between regulation and load following will be used in this study.

Statistical Analysis of Regulation

The basis for a statistical analysis of control area regulation requirements is described by Hirst and Kirby in [1]. It relies on the notion that certain of the temporal variations in net control area load can be attributed to random activities and actions of all customer loads (and even some generators) that do not exhibit a distinct pattern, but rather have characteristics of "noise" on a detailed plot of aggregate system load. Figure 37 shows a one-hour measurement of system load superimposed on a measurement of the same load that is "smoothed" to reveal the underlying trend.

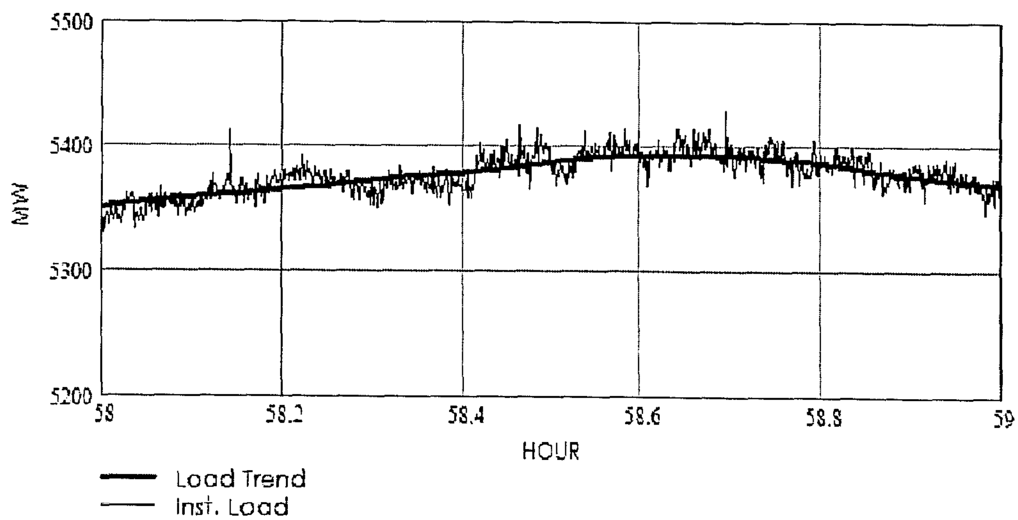


Figure 37: Instantaneous system load at 4 second resolution and load trend

Although the Hirst/Kirby method does not make any assumptions about correlations between subsets of the aggregate, a simplification can be made if the subsets are assumed to be uncorrelated, i.e. they are statistically independent. This allows the use of some straightforward algebra to analyze the impact of an individual portion of the aggregate load, and is very useful when considering the impacts of wind generation.

It should be noted that the statistical analysis described in [1] does not consider any specific details of the AGC load-frequency control algorithms or characteristics of the generating units providing regulation service. Nor does it explicitly address or mathematically relate to control performance as defined by the NERC standards CPS1 and CPS2. Rather, historical time-series load data is examined to simply quantify the range of regulation capability that would be required to compensate for the fast variations in net system load.

Separating the net system load fluctuations into two categories - fast, random fluctuations (with zero net energy) and a longer-term trend with variations - can be done by applying a rolling average computation (Figure 38) to time-series load data of sufficient resolution. The result of this calculation is then subtracted from the raw load data to extract the component of the overall fluctuation that is defined as regulation.

$$\text{Load following}_t = \text{Load}_{estimated\text{-}t} = \text{Mean}\,(L_{t-29} + L_{t-28} + \ldots + L_t + L_{t+1} + \ldots + L_{t+30})$$

$$\text{Regulation}_t = \text{Load}_t - \text{Load}_{estimated\text{-}t}\,.$$

Figure 38: Equations for separating regulation and load following from load (from[1]).

Application of the equations in Figure 38 to the raw load data from Figure 37 results in the regulation characteristics of Figure 39.

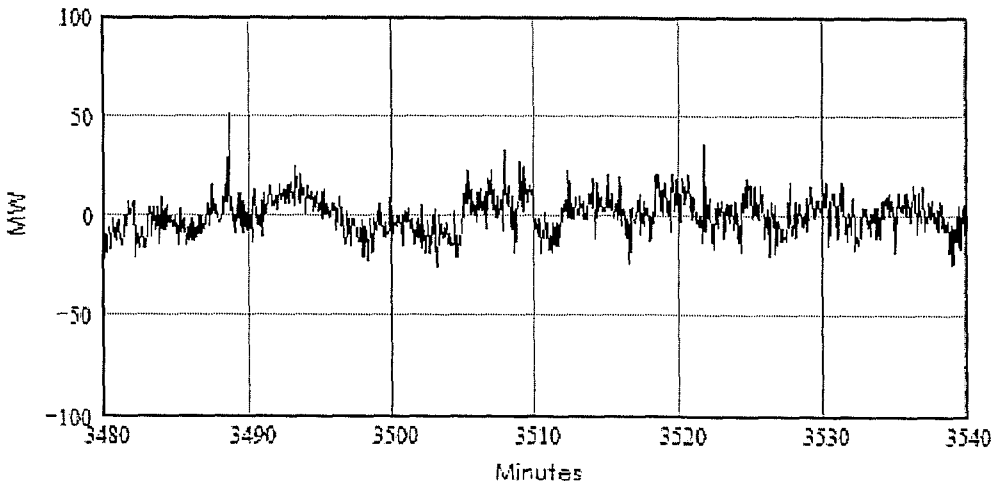


Figure 39: Regulation characteristics for raw load data of Figure 37.

Statistics for the resulting regulation time series are then generated. If the rolling average period is selected to make the energy component of the regulation characteristic zero, the mean of the sample will be near zero. The standard deviation of the samples will depend to some degree on the resolution of the raw data; for the very high resolution 4 second data used in these illustrations the standard deviation will be higher than if the raw data (or the regulation characteristic itself) were integrated or smoothed by a rolling average function. In [3], the authors examined data from several control areas and found that the appropriate time period was likely one to two minutes, and is influenced by system size, mix of generators on AGC, load composition, and AGC control logic.

The regulation requirement can be related to the standard deviation by applying a multiplying factor, e.g. 3 times the standard deviation to encompass 99% of all the deviations in the sample.

The above algorithms can be applied to the entire load or any subset for which suitable measurement data is available. If the regulation characteristics of the individual subsets are truly uncorrelated, the regulation characteristic of the combination can be calculated from the statistics of the individual characteristics as follows:

$$\sigma_T = \sqrt{\sum \sigma_i^2}$$

where

σ_i = standard deviation of regulation characteristic of subset of load

σ_T = standard deviation of regulation characteristics of total load

For purposes of this study, the individual components in the above equations will consist of each of the plants in the wind generation scenario and the total system load as projected for 2010.

Regulation Characteristics of Xcel-NSP System Load

For Xcel-NSP, system load data with resolution sufficient for analysis of regulation issues is not archived historically. A special archiving procedure was set up by Xcel operators to collect this data over a two week period beginning April 12, 2004. The raw data from this archive is shown in Figure 40.

The time-series were acquired at a 4 second resolution, or 21,600 values per day. Weekend days are clearly visible, as are a few periods with some bad data points (e.g. in the plot for April 15-17).

Because high-resolution data is available only for this period, it will be assumed that the regulation characteristic of the existing load is constant over the entire year.

In the analysis that follows, it is also assumed that with amount of capacity and type of units assigned to regulation duty current regulation performance for the Xcel-NSP system is adequate.

The raw data was processed as described in [1] by applying the following equations:

$$\mathrm{Load\_Trend}_k := \frac{1}{\mathrm{avg\_per}} \left(\sum_{n = k - \frac{1}{2}\cdot \mathrm{avg\_per} + 1}^{k + \frac{1}{2}\cdot \mathrm{avg\_per}} \mathrm{Load}_n \right)$$

where

$$\mathrm{avg\_per} := 300$$

$$\mathrm{avg\_per} \cdot 4 \cdot \mathrm{sec} = 20\,\mathrm{min}$$

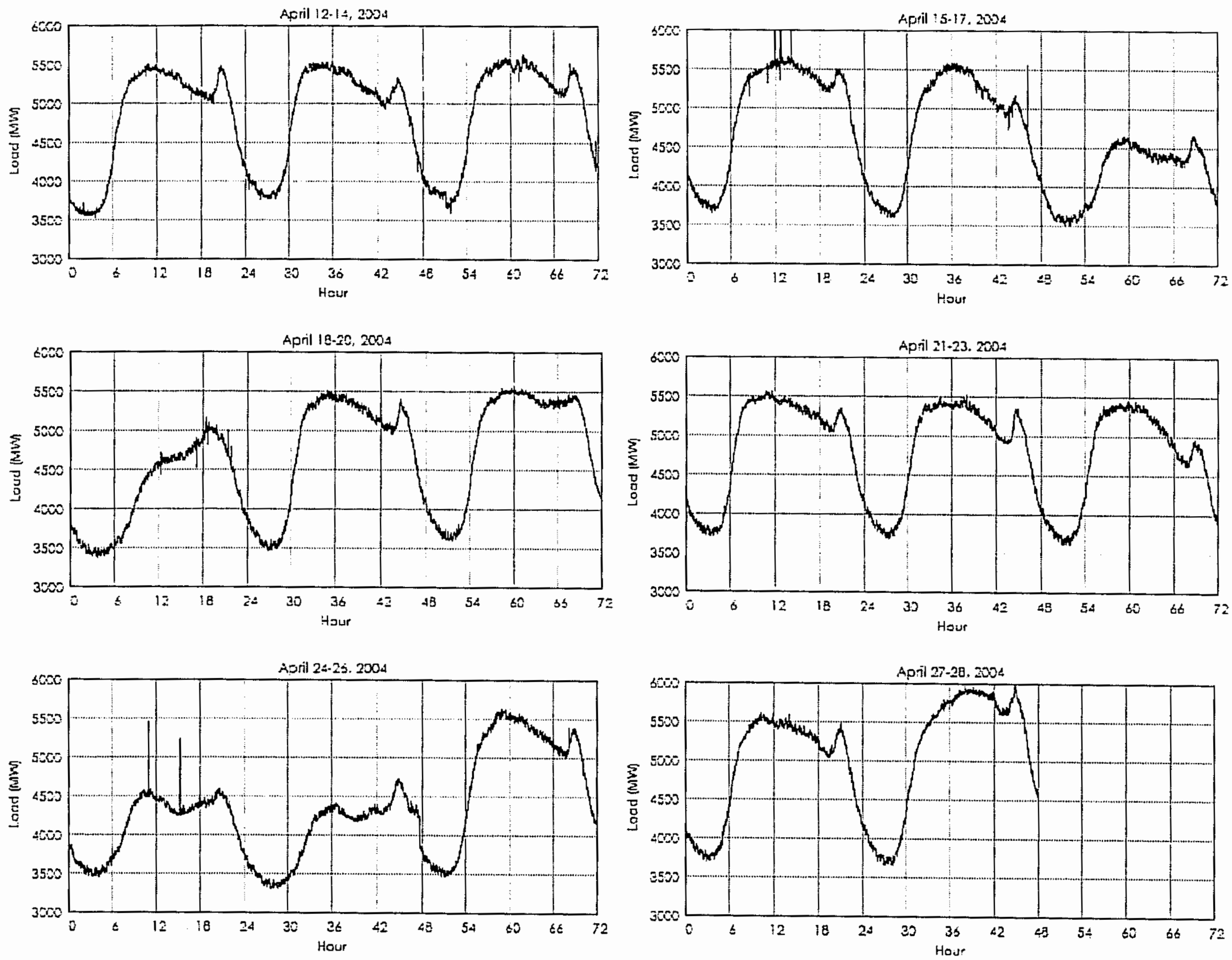


Figure 40: High-resolution load data archived from Xcel-NSP EMS.

and

$$Regulation_j := Load_j - Load\_Trend_j$$

A number of time averaging periods were used, with the 20 minute time average period determined to be the best in terms of the longest period still resulting in zero net energy. Figure 41 shows the raw data and the trend for the time series data with a 20 minute time-averaging period.

The regulation characteristic corresponding to the data in Figure 41 is shown in Figure 42.

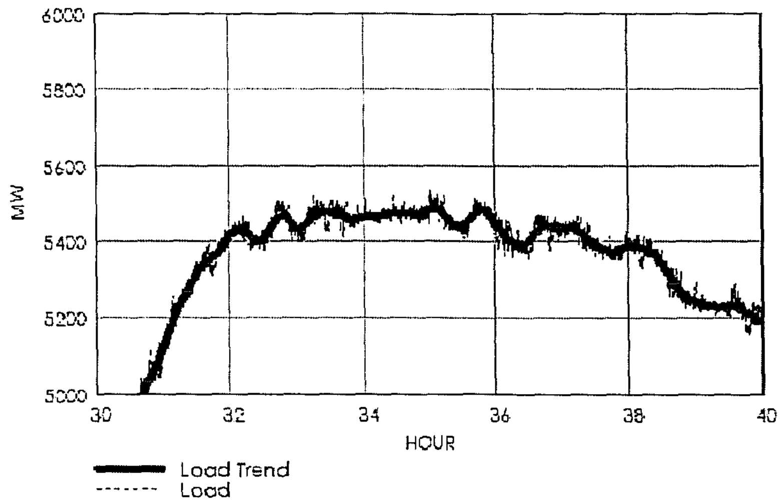


Figure 41: Raw load data and trend with 20 minute time-averaging period.

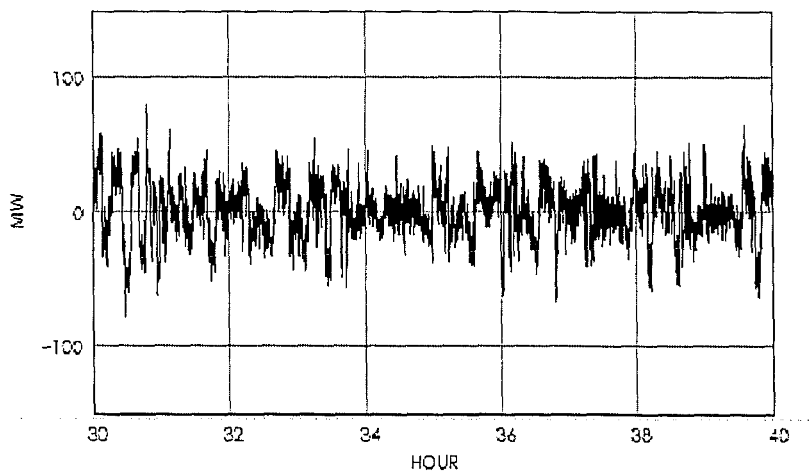


Figure 42: Regulation characteristic from Figure 41.

A twenty minute time-averaging period was applied to the two week data series. Statistics were computed for each of the segments of archive data. The regulation characteristic was computed using the 4 second data, which according to Hirst will lead to a higher regulation requirement. However, the results using the 4 second data align very well with current Xcel-NSP operating practice, so no additional smoothing of the regulation data was employed. Figure 43 shows the distribution of the regulation time series for the April 12-14 data segment.

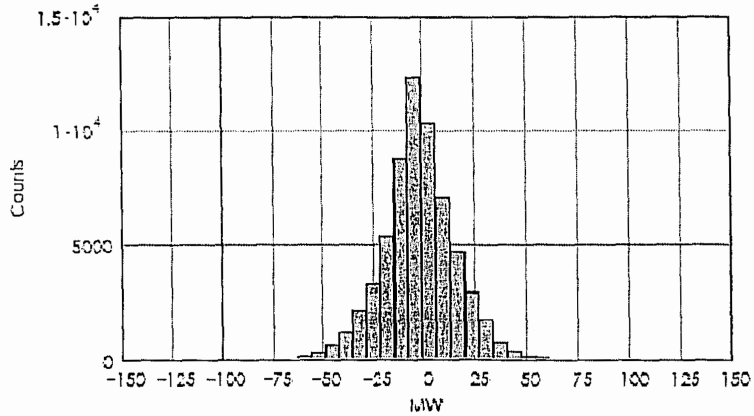


Figure 43: Distribution of regulation variations for April 12-14, 2004.

Results for all of the archive data are shown in Table 17. Currently, Xcel-NSP carries 60 MW of regulating reserve (up and down), which is just over three times the value shown in the table. Given that control performance for Xcel-NSP is satisfactory with 60 MW of regulating reserve, the statistical analysis approach seems to be at least partially validated by reality.

Table 17: Summary of Regulation Statistics for Xcel-NSP System Load, April 12-27, 2004

Data Set	Std. Dev (MW)	Variance (MW)	Comments
4/12-14	18.4	338.3	Ignored periods with bad data
4/15-17	14.9	221.1	
4/18-20	17.9	318.9	
4/21-23	17.9	320.3	
4/24-26	16.8	282.7	Ignored period with bad data
4/27-28	16.6	275.0	

Characteristics of Proposed Wind Generation

The approach for determining the regulation requirements for the prospective wind generation in the 2010 scenario was based on high-resolution data collected by NREL at the Buffalo Ridge Substation and the Lake Benton II wind plant in southwestern Minnesota. These data sets consist of 1 second measurements of real power, reactive power, and voltage over a period approaching 3 years. The turbine groups being monitored are each comprised of a different number of Enron Wind Corporation Z750 wind turbines. The turbine count and nameplate capacity for each of the measurement locations is given in Table 18.

The data sets are useful for examining the regulation behavior of wind plants because of the differing turbine numbers and the synchronization of the measurements. Short-term output fluctuations of individual wind turbines and groups of turbines are very difficult to characterize analytically due to the complex micro-scale meteorology and turbine factors from which they derive. The measurement data provides an empirical foundation for estimating and approximating this variability.

Table 18: Plant Details for NREL Measurement Data

Interconnection	# of Turbines	Nameplate Capacity (MW)
Delta	30	22.50
Echo	39	29.25
Foxtrot	14	10.50
Golf	55	41.25
Total	280	210.00

Power output data consisting of 1 second samples over a 24 hour period for each of the measurement locations is shown in Figure 44. An expanded view over a 30 minute period beginning at Hour 5 is shown in Figure 45.

Some initial observations regarding this data include:

- The correlation between the power profiles for the individual turbine groups is apparent over the longer time scales.
- On the shortest time frames, the fluctuations show little if any correlation.
- The fast output fluctuations for the "Total" measurement comprising 280 turbines are much smaller as a fraction of rating that the same fluctuations from groups with smaller numbers of turbines.

These observations will form the basis of the method for estimating the regulation requirements of the wind plants making up the 1500 MW scenario for the study.

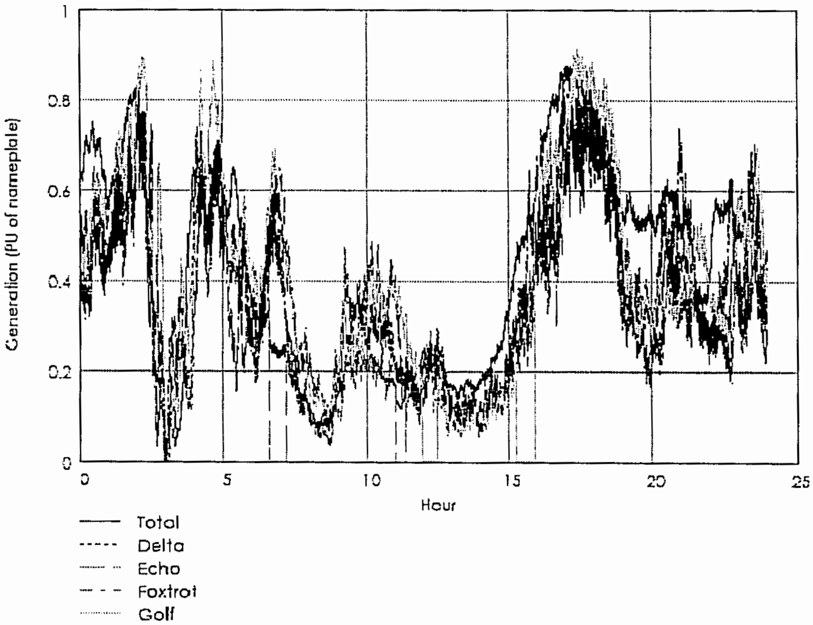


Figure 44: Portion of NREL measurement data showing per-unitized output at each monitoring location.

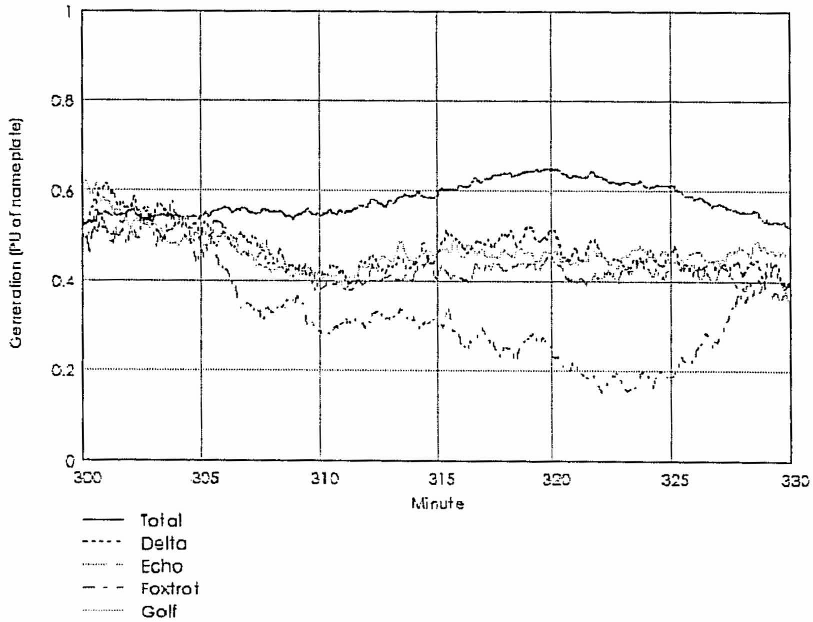


Figure 45: Expanded view of Figure 44 beginning at Hour 5.

The time-averaging method that was used to separate the regulation characteristic from the underlying trend for the system load data is applied to the wind generation measurement data.

The trend characteristic that results from a 20 minute time-averaging period for the data shown in the previous two figures is plotted in Figure 46. While the trend characteristic exhibits more variation than the system load, it is apparent from the figure that the trends from Figure 44 are captured well with this time-averaging period.

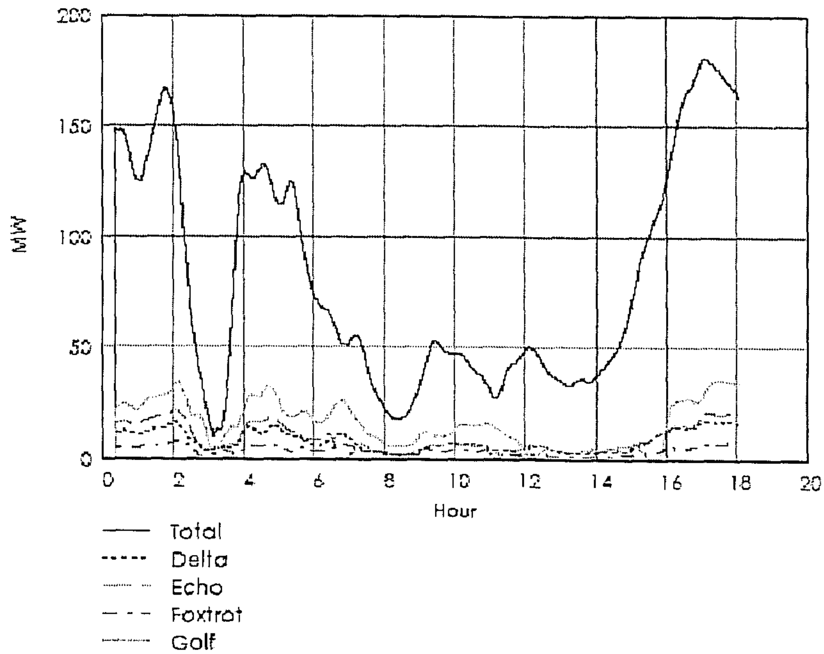


Figure 46: Trend characteristic extracted from raw data of Figure 44 with a 20 minute time averaging period.

A total of nine 24 hour periods of wind generation data were processed to extract the regulation characteristics. With the 20 minute time-averaging period, the mean of regulation characteristic for each of the measurement locations was very near zero. The standard deviations for each measurement location and day sample are given in Table 19.

The calculated standard deviations are for all hours and operating conditions in the samples, and do not distinguish between periods of light, moderate, or strong winds. Plots of the results for each sample day on a semi-log chart, as shown in Figure 47, reveal a dependence between the number of turbines in the measurement group and the standard deviation. The plots also show that range of standard deviations for the sample increases as the number of turbines in the measurement group decreases.

The preceding analysis is a simple quantification of a principle with which most persons familiar with wind generation already know – wind generation variability declines (as a percentage) as the number of turbines increases. The quantification presented here is also not exhaustive, and focuses on a single turbine model in a single geographic region. From the numbers presented here, however, conservative estimates can safely be made.

Table 19: Standard Deviation of Regulation Characteristic for NREL Measurement Locations

Day	Measurement Location Foxtrot (%)	Delta (%)	Echo (%)	Golf (%)	Total (%)
111	4.871	3.231	2.383	2.378	0.899
60	2.346	2.001	1.598	1.302	0.635
120	2.886	2.241	1.802	1.848	0.84
180	2.805	2.317	1.937	1.332	0.636
240	3.538	3.092	2.32	2.232	1.048
302	2.406	2.06	1.824	1.69	0.822
360	4.505	1.918	2.617	1.327	0.849
30	3.428	2.625	2.579	1.975	1.055
75	3.428	1.666	1.695	1.435	0.645
Average	3.36	2.35	2.08	1.72	0.83

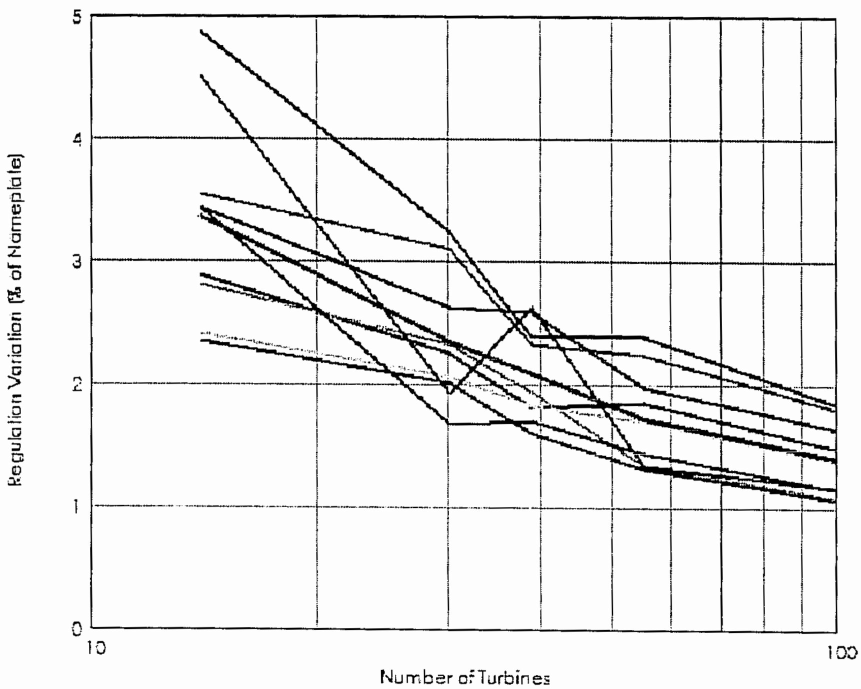


Figure 47: Variation of the standard deviation of the regulation characteristic for each of nine sample days by number of turbines comprising measurement group.

Calculation of Incremental Regulating Requirements

The increment in regulating reserve for the Xcel-NSP control area due to 1500 MW of wind generation can be approximately calculated using the simple expression described earlier:

$$\sigma_T = \sqrt{\sum \sigma_i^{\,2}}$$

where

σ_i = standard deviation of regulation characteristic of subset of load

σ_T = standard deviation of regulation characteristics of total load

The standard deviation of the regulation characteristic for the existing Xcel-NSP control area load was calculated to be 18 MW:

$$\sigma_L := 18 \cdot \mathrm{MW}$$

The procedure for synthesizing the system load for the year 2010 involves a simple scaling of the existing load to match the projected peak for that year. By doing so, the regulation characteristic would be similarly scaled, increasing the standard deviation of the regulation characteristic for the load in 2010 to 20.2 MW:

$$\sigma'_L = 20.2\,\mathrm{MW}$$

The total wind generation is assumed to consist of 50 separate "plants" of 30 MW each. With larger turbines comprising the newer plants the number of turbines in each plant could be as low as 15. While they are significantly larger than the 750 kW turbines upon which the empirical analysis was based, the standard deviation of the regulation requirement for each plant is conservatively estimated to be 5%:

$$\sigma_{wi} = 1.5\,\mathrm{MW}$$

Using the formula from above, the standard deviation for the combination of the projected load and the 1500 MW of wind generation can be calculated:

$$\sigma_T := \sqrt{{\sigma'_L}^2 + 50 \cdot \left(\sigma_{wi}^{\,2}\right)}$$

$$\sigma_T = 22.8\,\mathrm{MW}$$

Assuming that the regulation requirement is equal to three times the standard deviation of the regulation characteristic (which was shown to be a reasonable assumption for current practice in the Xcel-NSP control area), the new regulation requirement will be **68.4 MW**, or an increase of **7.8 MW** over what is projected for the load alone.

Conclusions

The statistical methodology employed here indicates that the addition of 1500 MW of wind generation in the control area would have a small but calculable impact on the regulation reserve required to hold CPS1 performance constant.

Using relatively conservative assumptions regarding the regulation demand from each of the fifty 30 MW "wind plants" in the scenario, the increase in regulation reserves for the control area would be less than 10 MW.

A simple method for estimate the economic impact of this increased regulating requirement is to compute the "opportunity cost" of having to reserve that incremental capacity for regulation rather than producing energy and selling it. At present, much of the regulation duty for the Xcel-NSP control area is provided by one or more large coal-fired units (SherCo 1 &2). Assuming a production cost of $10/MWH, a selling price of $25/MWH, the approximate annual cost to reserve this additional capacity for system regulation is

$$7.8MW \cdot 8760\frac{hours}{year} \cdot (25-10)\frac{\$}{MWH} = \$1{,}024{,}920$$

At an average capacity factor of 35%, the annual production from the 1500 MW of wind generation would be 4.5 million MWH each year.

The cost of the incremental regulation service would be

$$\frac{\$1{,}024{,}920}{4{,}500{,}000MWH} = \$0.23 \Big/ MWH$$

Capacity value provides an alternative method for costing the incremental regulation requirement. Using a value of $10/kW-month or $120/kw-year, the annual cost of allocating an additional 7.8 MW of capacity to regulation duty comes out to be $936,000, about the same as the number arrived at through the simple opportunity cost calculation. This number and the previous result are not additive, however. By either method, the cost to Xcel for providing the incremental regulation capacity due to the 1500 MW of wind generation in the control area is about $1 million per year.

Impact of Wind Generation on Generation Ramping – Hourly Analysis

The hour-by-hour changes in forecast system load are important considerations for power system operators in committing and scheduling supply resources. During the "shoulder" periods of the daily cycle, the system load will either rise or fall quite quickly. Around the peak hours and overnight, hourly load changes will be much smaller. The scheduling procedure must take these expected hourly changes into account to ensure that there is enough unused online capacity (during ramps up) or unloadable capacity (during ramps down) to follow the changes in the load. If the ramping capability of the units available falls short of what is required, emergency reserves or transactions with other control areas would be tapped to meet these trends.

Variations in wind energy do not necessarily follow any daily pattern. The question for the schedulers and operators then becomes one of how wind generation might affect the control area need for ramping capability, since the normal ramping requirements for the existing system load are well known from history and experience.

The analytical tool used to make decisions regarding which generating units need to be made available to meet the forecast system load for a future period - usually the next day or a few days - is the unit commitment program. The fundamental algorithms in a unit commitment program explore a very large number of combinations and permutations of generating units to find the line-up that will meet the load at the lowest cost. The solution must honor a myriad of constraints, some related to the capabilities and realities of individual generating units and others stemming from considerations for maintaining system security, control performance, and adherence to reliability council operating guidelines. Limitations on number of units' starts and stops over period, maximum and minimum operating levels, maximum and minimum rates of change in output, and minimum run times fall into the first category. Requirements for system regulation, spinning reserves, and operating reserves are examples of the second category.

Because individual units have ramp rate limitations, the impacts of wind generation on the net control area demand as described in this section give an indication of how wind generation changes the "problem" that must be solved by the unit commitment program.

Analysis of Historical Load Data and Synthesized Wind Generation Data

The three-year wind generation time series data developed for this study, aggregated to the hourly level, in conjunction with an Xcel-NSP hourly system load time-series for the same years was analyzed. Each of the annual hourly system load time series was scaled so that the peak hour matches the anticipated 2010 system peak of 9943 MW.

A cursory examination of the hourly net system load changes with and without the wind generation was conducted first. The complete time series data sets for load and wind generation are plotted in Figure 48. Possible impacts of wind generation on ramping requirements are shown in Figure 49. Periods to note are those where the ramping requirement is modified either in magnitude or sign. Also of note is the effect that this penetration of wind generation has on the overall daily "shape" of the load curve.

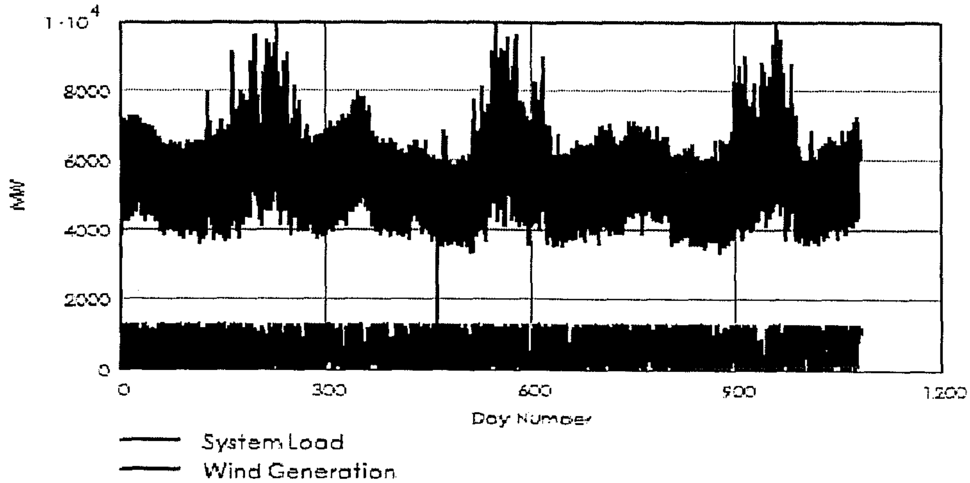


Figure 48: System Load and Wind Generation data sets used in assessment of ramping requirements.

For this analysis, a characteristic of the wind generation model should be noted. The computational model used to develop the wind speed time series upon which the individual wind plant and aggregate wind generation values are based actually re-creates historical weather. For this study, the years 2000, 2002, and 2003 were selected. The corresponding Xcel-NSP system load data used in this analysis is also from those years. Therefore, any correlations that exist between wind generation and control area load, such as those that rise from the fact that weather systems have an influence on both quantities, are theoretically embedded in the data sets being used here. It is outside the scope of this study to evaluate the sources of such correlations or to what extent they influence the data sets. At the same time, however, there is some comfort in knowing that if they exist and are significant, they are accounted for in the data.

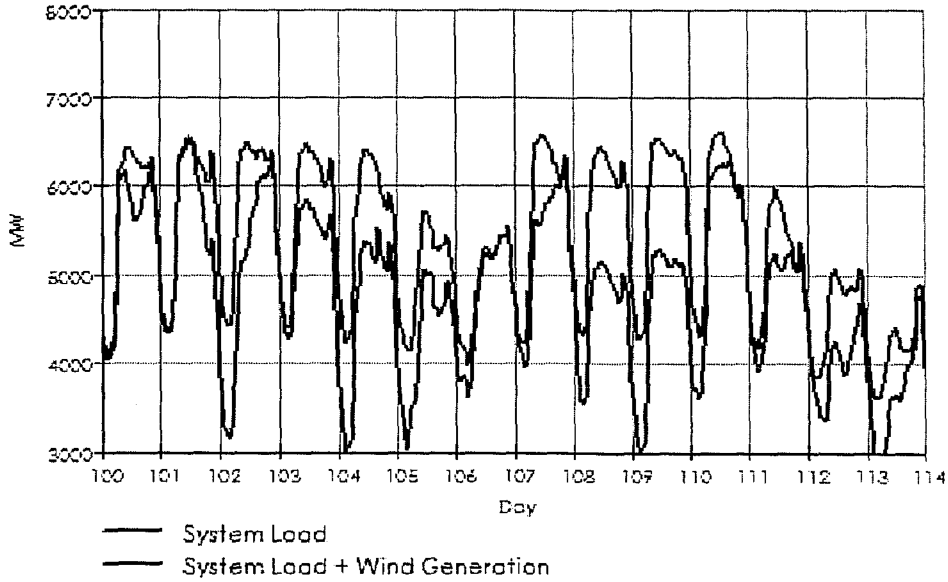


Figure 49: Expanded view of Figure 48 beginning on Day 100.

The hour-to-hour load changes for the three years of data are shown in Figure 50 and Figure 51. A slight broadening of the distribution is discernable - the standard deviation for the load data only is 280 MW; with wind generation added the standard deviation increases to 294 MW. Both distributions are quite symmetrical with a mean very near zero. Note that with wind generation added, the number of hours with very little load change decreases from just under 10 percent to about 8 percent.

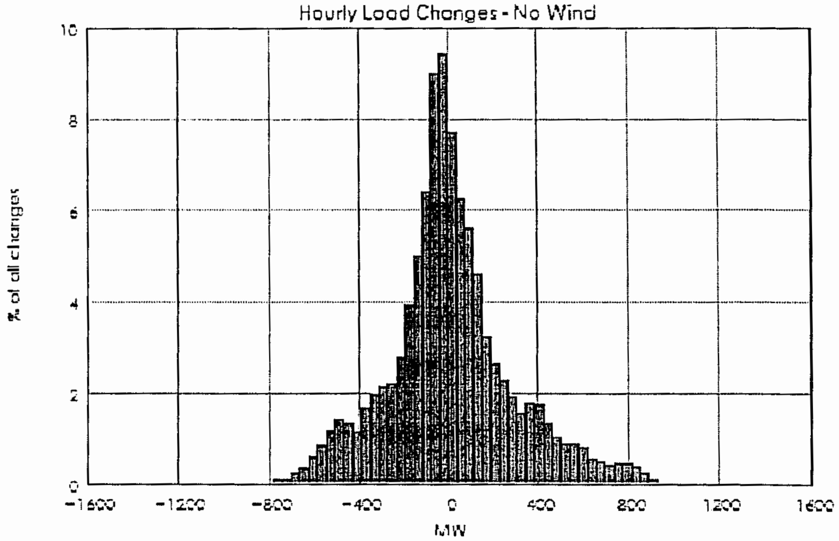


Figure 50: Distribution of hourly changes in system load without wind for three year sample.

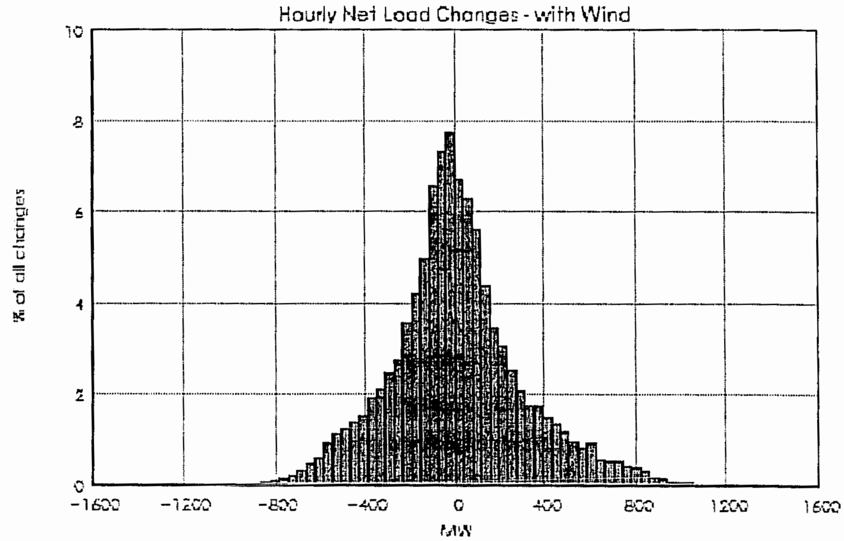


Figure 51: Distribution of hourly changes in system load with wind for three year sample.

Another salient feature of Figure 51 is that the number of very large hourly changes (greater than +/- 800 MW) is increased only slightly with wind generation. The effect here appears to be substantially smaller than that reported in some recent studies, but similar to some others. Two points should be made, however. First, the penetration level in this study (15%) is only half of what was considered in [4]. Second, the distributions shown here treat all hours equally. With respect to generation schedules developed for conventional control area loads, the assumption that the same amount of ramping capability is available for each hour of the day is not valid. Ramping requirements for familiar control area loads will vary considerably over the course of the day, and optimal generation unit commitment plans and schedules likely take this into consideration. Therefore, a more detailed view of how ramping requirements are affected by wind generation is necessary.

Using the data sets described above, the control area hourly load changes with and without wind generation were analyzed by time of day. The hourly load ramp for hours ending 3, 6, 9, 12, 15, 18, 21, and 24 are plotted in Figure 52 for each day of the sample data set. The hourly changes with wind generation are shown in Figure 53.

The seasonal as well as time-of-day dependence for ramping requirements can be seen clearly in the graphs. Without wind generation, the hourly changes during the middle of the night and for the peak hours (which vary by season) are smaller than those during the shoulder periods. The morning load pick up is easily seen by comparing Hours Ending 3, 6, and 9 and to a lesser extent during the peak hours, while the evening load drop is visible in Hour Ending 24 and even in Hour Ending 21 during certain seasons.

Figure 54 plots the hourly load changes (shown as bars rather than lines) with and without wind generation for Hours Ending 6, 12, and 18. Notable here is the significantly increased number of "down ramps" in the early morning resulting increase in wind generation in excess of the load pickup.

Statistics on the hourly ramping data provide some additional insight. Figure 55 shows the computed average ramping requirement for each hour of the day, by season of the year, both with and without wind generation. The notable characteristic of these graphs is how little the ramping requirements appear to be impacted by wind generation.

This impact is much clearer in Figure 56, which shows the standard deviations of the populations from which the averages in the previous figure were calculated. The graphs show that wind generation can increase the ramping requirement for any hour each season of the year. This qualitative conclusion is not surprising, and maybe even obvious given the relatively high penetration level being considered in this study. The standard deviations of the distributions do, however, help to convey the relative magnitude of the impact through the operating day.

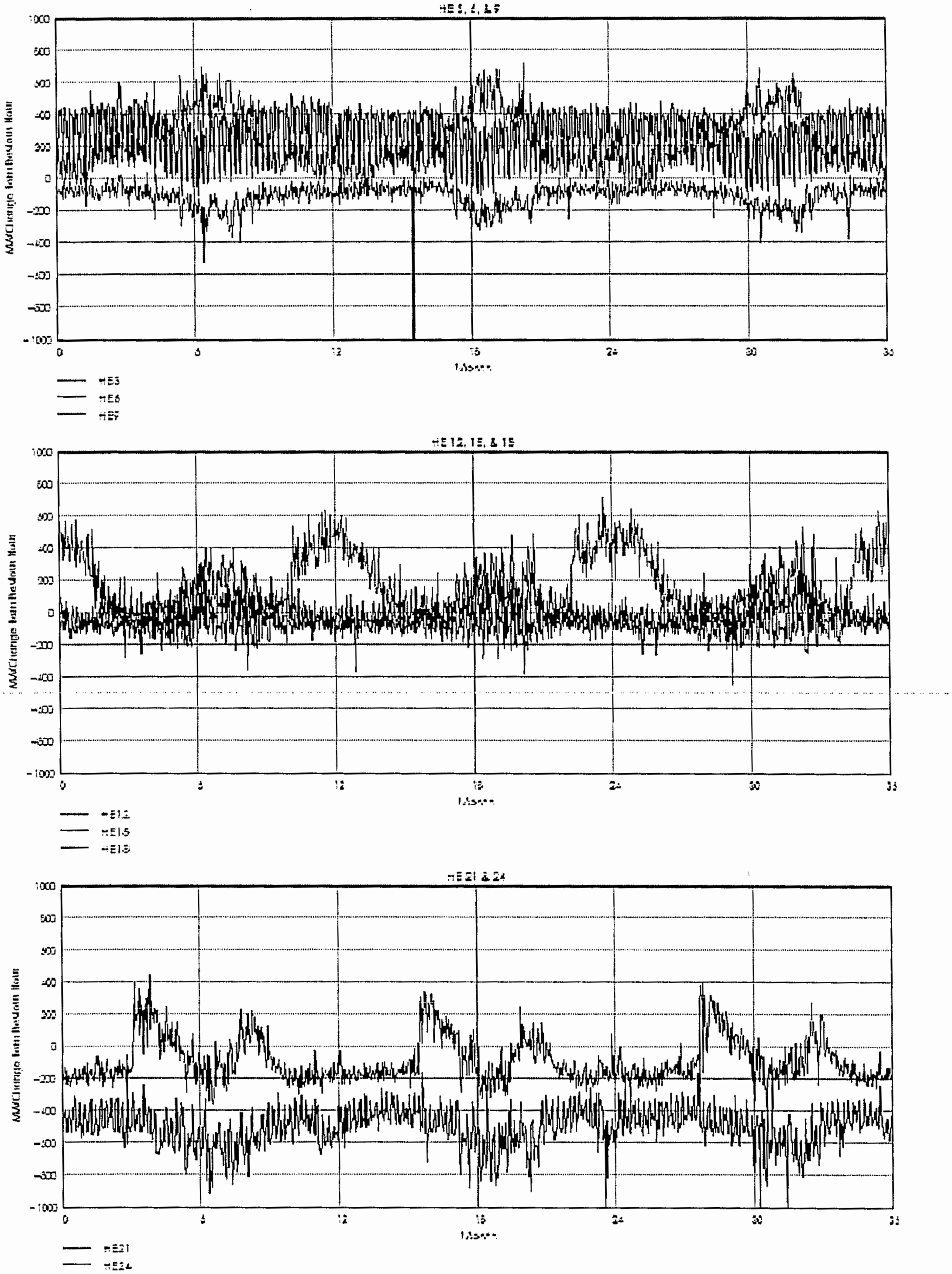


Figure 52: Control area hourly load (no wind) changes for hours ending 3, 6, 9, 12, 15, 18 ,21, & 24.

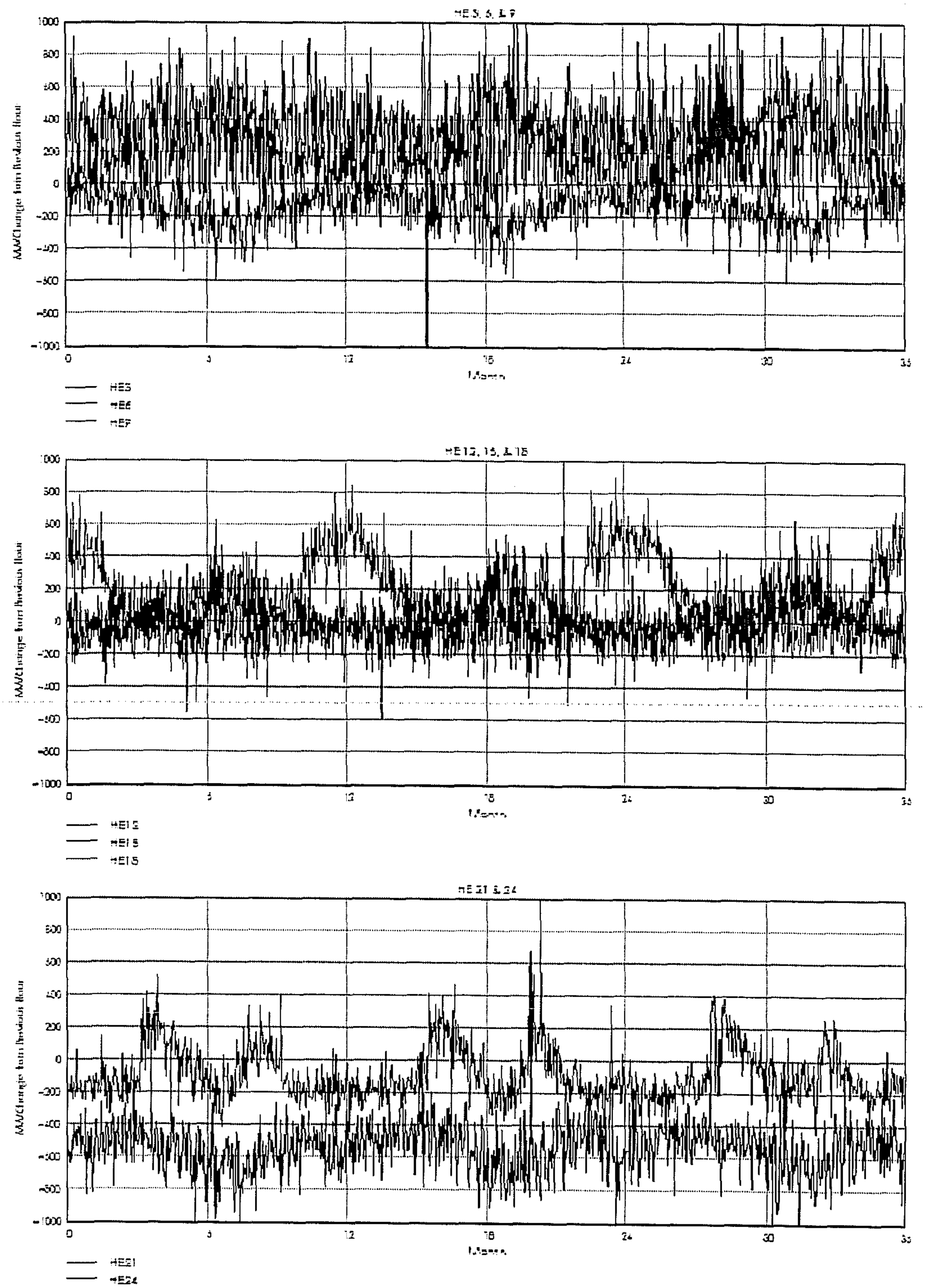


Figure 53: Control area hourly load (with wind) changes for hours ending 3, 6, 9, 12, 15,18,21, & 24.

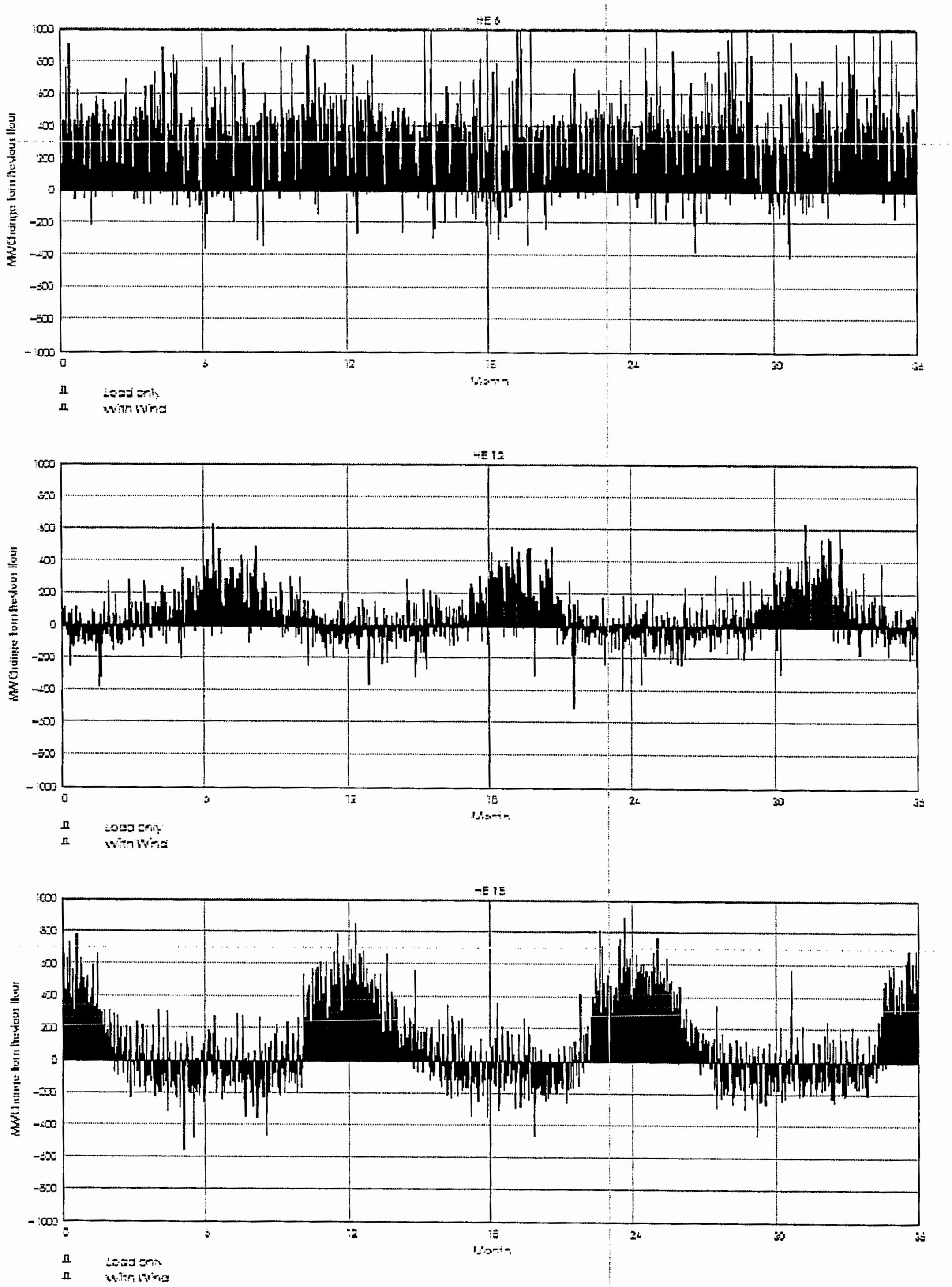


Figure 54: Control area hourly load changes for hours ending 6, 12 & 18. Load only (red) and with wind (blue)

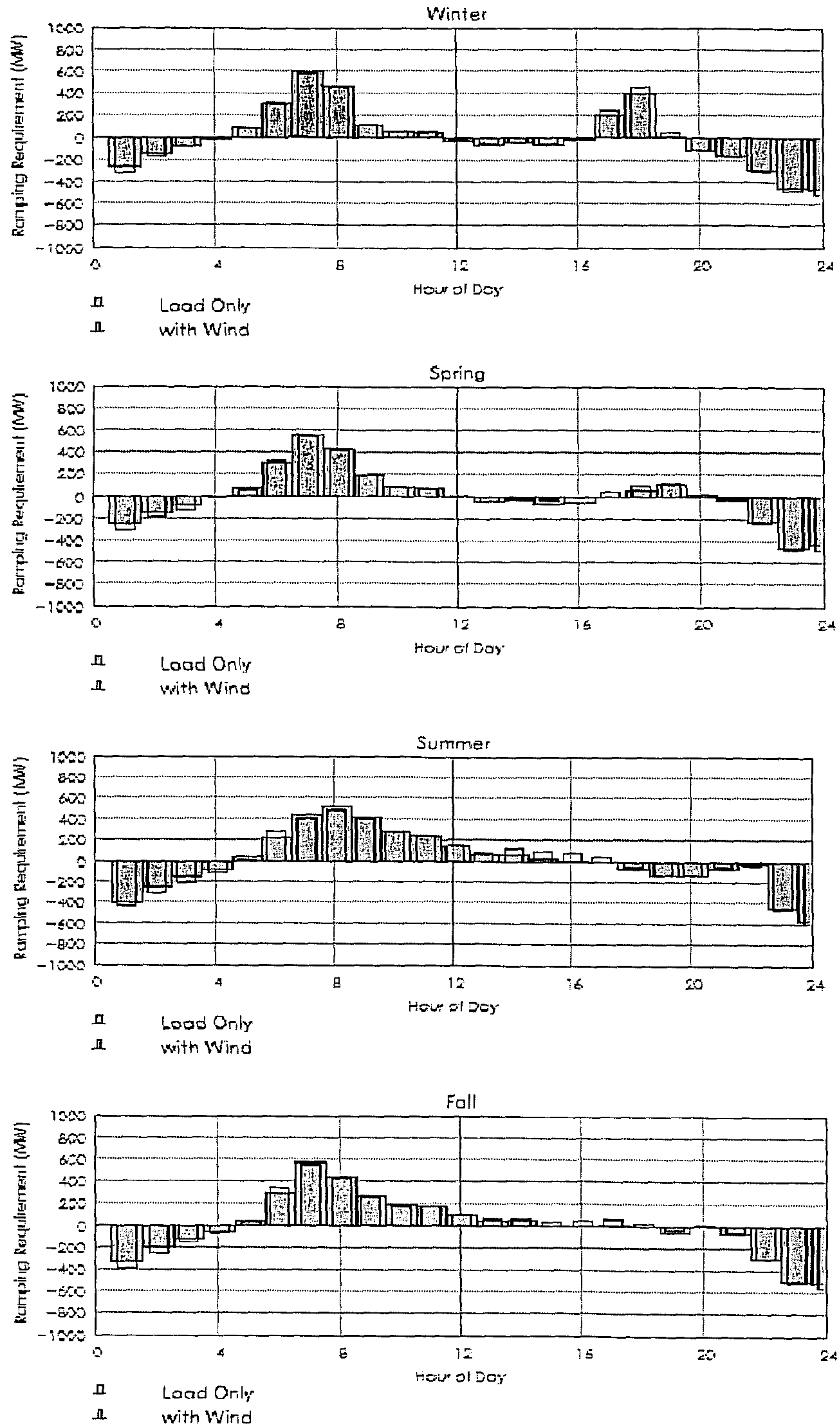


Figure 55: Average ramping requirements with and without wind for each hour of the day, by season.

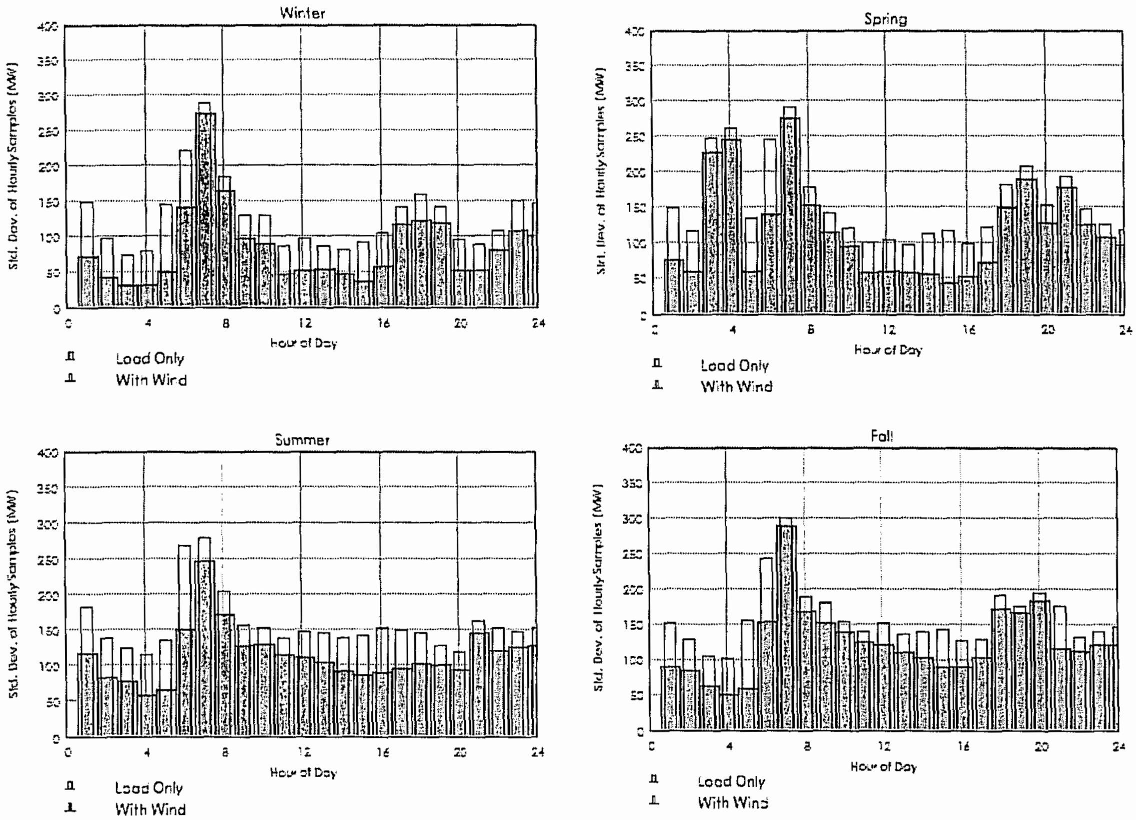


Figure 56: Standard deviation of ramping requirements with and without wind generation, by hour of day and season.

A final view of this data is created by examining the actual distributions of ramp rates. Such a view provides a better illustration of whether the impact of wind generation on the ramp requirement is in the up or down direction. In addition, the actual shapes of the distributions provide an indication of the usefulness of the standard deviation for calculations, since the distributions are not necessarily Gaussian.

Distributions are created for each season of the year. With three years total of data, each sample data set therefore contains about 270 values.

The first observation from the hours depicted is that wind generation can substantially increase the hourly ramp rate during certain seasons and hours of the day. Figure 57 (HE 3) and Figure 59 (HE 6) are the best examples. During these hours, the ramping requirement is high because of substantial changes in the load. With wind generation changing in the opposite direction, the ramping requirement becomes even higher.

Secondly, while not related to wind generation, the bi-modal distributions for the morning pickup hours in each season are interesting. The unique shape of the distribution is due to the fact that weekdays and weekend days are lumped together in the sample.

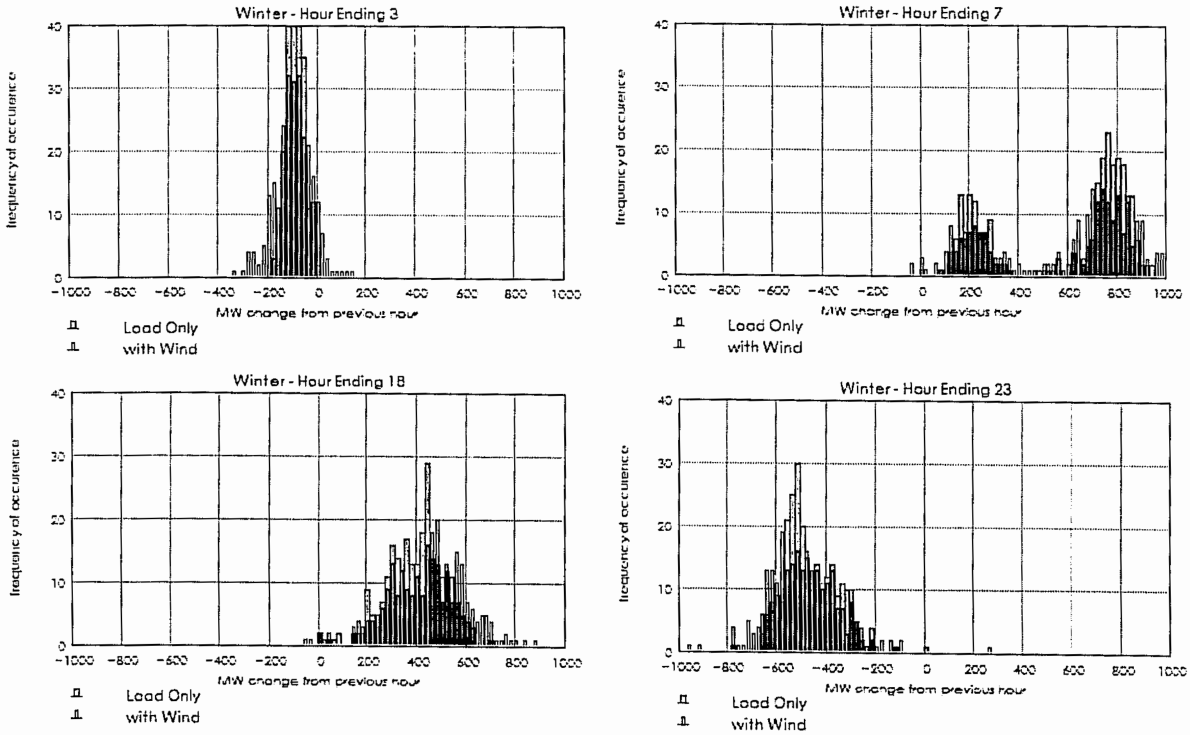


Figure 57: Ramping requirements with and without wind generation for selected hours during the winter season.

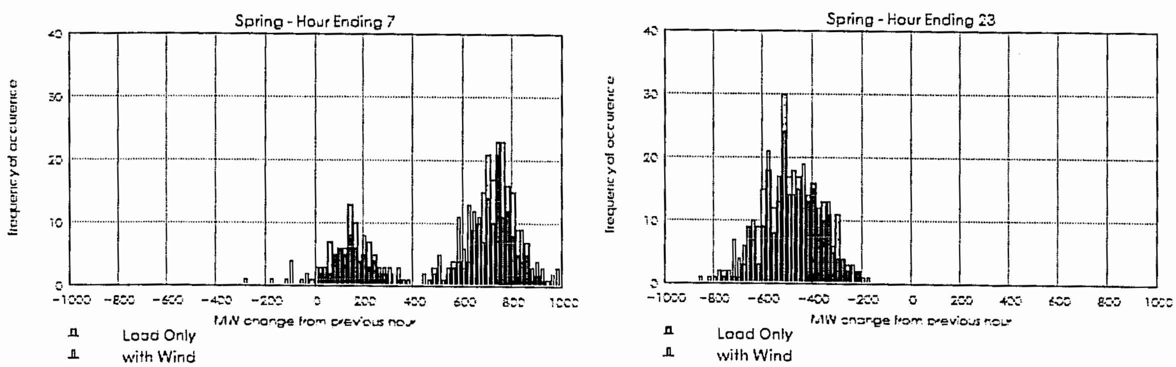


Figure 58: Ramping requirement with and without wind generation for selected hours during spring.

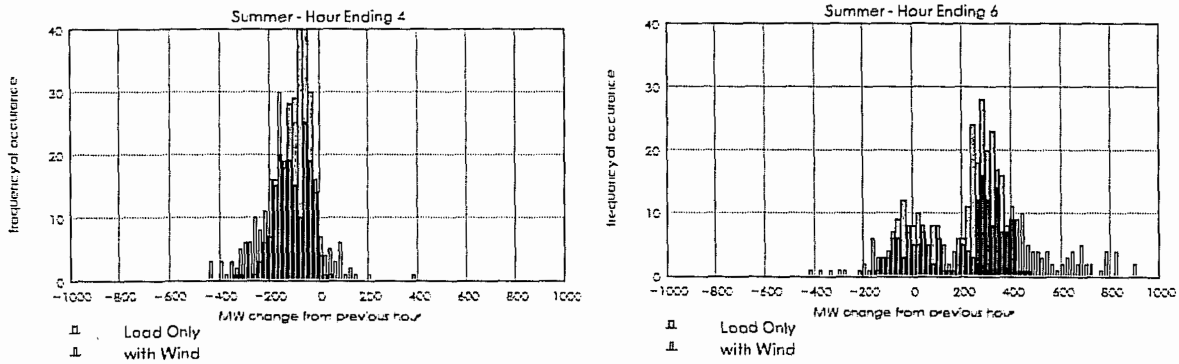


Figure 59: Ramping requirement with and without wind generation for selected hours during summer.

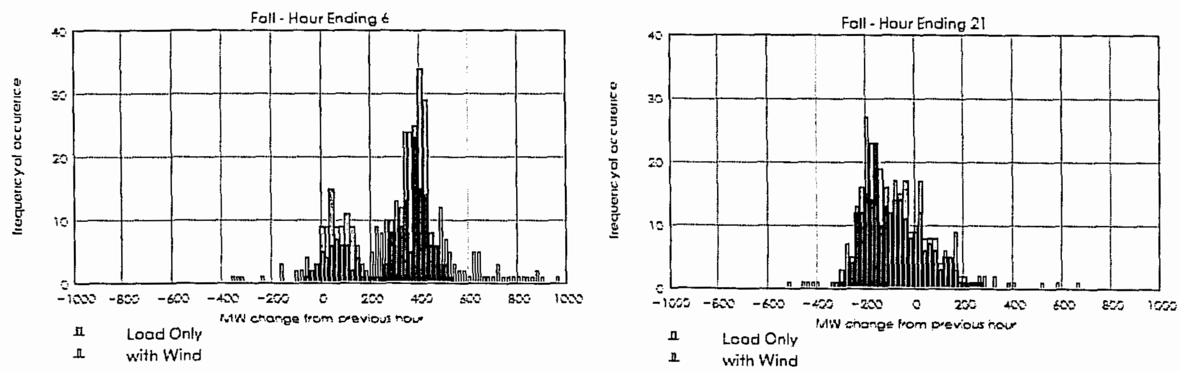


Figure 60: Ramping requirement with and without wind generation for selected hours during fall.

Assessment of Wind Generation Impacts on Ramping Requirements

The ramping requirements addressed here are based on a retrospective or historical view of hourly system load characteristics and synthesized wind generation data. The preceding graphs and illustrations leave little doubt that the 1500 MW of wind generation in a 10,000 MW control area will, at least at times, increase the ramp rate required to meet the load on an hourly basis.

Quantifying the cost impact is the important question for this study. The analysis of this section, while revealing with respect to the interplay between the temporal behavior of the system load and wind generation, is inadequate for a detailed quantitative analysis of these economic impacts.

Computation of the cost impacts of increased generation ramp rate during certain hours of the day and seasons of the year is captured by the analytical methodology of the next section of the report. At the hourly level, where the analysis of this section was focused, system operators commit and schedule generation to not only meet the daily energy requirements for the load, but also to transition hour-by-hour through the forecast daily load patterns out to the study horizon. As will be described, the influence of wind generation on the net control area load against which the other supply resources are committed and scheduled, along with the economic consequences in terms of increased production cost is captured in the analytical methodology at the hourly level.

Unit Commitment and Scheduling with Wind Generation

The objective of short-term power system planning and scheduling is to minimize production cost against a myriad of constraints and limitations necessary for maintaining power system security and the integrity of power system equipment. The procedure for committing and scheduling supply resources is a forward-looking exercise that is necessarily based on forecasts and estimates of conditions to come. When actual conditions do not match the assumptions upon which the plan is based, the reality is likely to be sub-optimal. The accuracy with which these future conditions can be estimated is critical to achieving the primary objective for generation scheduling.

The variability and predictability (or lack thereof) of wind generation brings some new dimensions to this process. While hourly loads for the coming days or week cannot be predicted with complete accuracy, the substantial body of historical data and operating experience in a given control area has allowed the uncertainty embedded in load forecasts to be at least implicitly included in the planning process. While the actual hourly load values may differ from the forecast values by a significant amount, power system planners and operators are assured that the load will rise in the morning, peak at some fairly predictable hour given the type of day and season of the year, and resemble thousands of other observed load patterns in most respects.

With significant wind generation in the control area, there is the potential for new and previously unobserved patters of net system load to appear. Wind generation ramping up quickly in the morning or dropping late in the day can turn a "ramp-up" or "ramp-down" period around for the system operators. At the other extreme, additional controllable resources may have to be deployed to follow hourly changes in net control area demand well above what could be expected from experience.

In this section, the data, analytical methodology, and results for the expected impacts on generation commitment and scheduling in the Xcel-NSP control area will be described.

Overview

The wind generation scenario in this study equates to a 15% penetration level (based upon nameplate wind generation and system peak load). However, there will be a large number of hours during the year when wind generation is serving a much larger percentage of the control area load. A quick analysis of the hourly load and wind generation data from the previous sections shows that the ratio of wind generation to system load regularly exceeds 30%, and ranges to as high as 36% for a small number of hours. During these conditions, where wind generation is obviously high and system load is low or near the daily minimum, the deployment of Xcel-NSP supply resources will likely be very much different than has been experienced to date.

In addition, the high penetration levels are achieved only temporarily, so there must be enough generation available to quickly replace the wind generation should it decline. The importance of knowing in advance that wind generation will change substantially, especially when it undergoes a relatively rapid change from high to low, is obvious here.

The hourly analysis described here focuses on the short-term planning procedures that involve decisions to make units available for generation (unit commitment) and scheduling them for operation to achieve the lowest production cost over the study horizon. The analytical tool employed for this analysis is the same one used by the operators to develop day-ahead schedules.

The analytical method involves sets of cases that will allow the impact of wind generation on the operating cost at the hourly level to be calculated. The cases are also defined to closely mimic the daily activities of the power system schedulers.

Methodology for Hourly Analysis

The analytical methodology must capture the extra system operating costs that are incurred due to:

1. The variability of wind generation, and
2. The fact that the actual hourly delivery of wind generation differs from what was used to develop the operating plan.

At Xcel Energy, those responsible for the NSP system generate daily schedules for internal resources and transactions in the early morning of the previous day. Load forecasts are adjusted for the next several days based on updated information, and a unit commitment and scheduling program is run to develop an operating plan with the minimum cost against the variety of constraints. The plan establishes which generating units are to be available, how much power will be bought from and sold to other control areas for each hour of the day, and where the available generating units should be dispatched on an hourly basis to achieve the lowest cost of production for the forecast load.

As the next day actually unfolds, chances are quite high that reality will be somewhat different from what was projected. Some of this difference may be due to events that cannot be anticipated, like forced outages of generating units, while other parts may be due to errors in forecasting. Whatever the source, these departures from schedule must then be remedied in the real-time operating regime.

Figure 61 illustrates the approach used in this study that captures the points 1) and 2) from above and also maps reasonably well to the Xcel practice for short-term operations planning.

The core of the method is a software tool that performs unit commitment and economic dispatch (hour-by-hour scheduling) for a set of chronological hourly loads and the defined power system model. It is assumed that the analysis is performed on a daily basis. Three cases for each operating period are defined, with impacts of wind generation extracted from comparisons of the results for these cases.

The initial case is referred to as the reference or "base" case. The case is defined so that the wind generation for the day is delivered in such a way as to have minimum impact according to points 1 and 2 above. The production cost for the period, minus the amount paid for the wind generation (which is assumed to be a "must take" resource) is the baseline production cost.

In this base case, the total energy provided by wind generation over the course of the day is assumed to be delivered on a "flat' profile, where the hourly value is 1/24th of the daily total. The rationale for this assumption will be discussed later.

The second case represents activities of the Xcel-NSP system schedulers as they prepare the operating plan for the next day. Here, hour-by-hour forecasts of system load and wind generation are used to develop an operating schedule for the next day. It is assumed that this schedule is being prepared early in the morning prior to the actual day ("day-ahead", or DA), so that the forecast data is for 16 to 40 hours into the future. This is a much more important consideration for wind generation than it is for load.

It must be noted that in the first two cases, the unit commitment program determines both an optimal commitment of generating units and a lowest-cost schedule. As such, any unit in the inventory may be deployed within its operating constraints.

The third and final case in this aspect of the hourly analysis is one intended to show how the optimal plan performs when the actual wind generation differs from the forecast by an expected amount. The key here is that the program is not allowed to "optimize", but rather is forced to live with the commitment schedule developed the previous day and adjust the operating units to meet the actual net of load and wind generation.

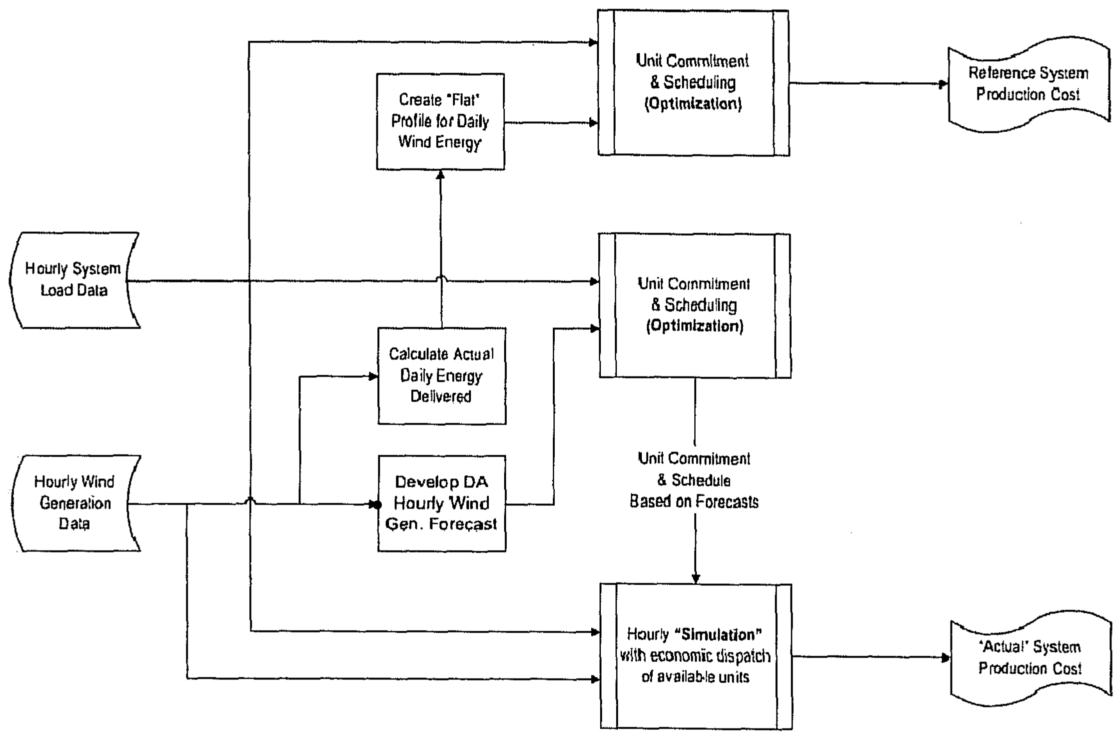


Figure 61: Overview of methodology for hourly analysis

The results of the simulation case are compared to the reference case to determine the impacts of wind generation. The primary metric is production cost. The primary reasons that the actual product costs will exceed those of the base case are:

1. The actual delivery of wind generation has substantial hour-to-hour variability that must be compensated by other resources.
2. The errors in hourly wind generation forecast for the next day result in certain hours where the available resources cannot be adjusted to serve the load. In the parlance of the unit commitment program, this is referred to as "unserved" energy; in reality this energy would be procured by the real-time operators through hour-ahead transactions or possibly by the deployment of quick-start, but expensive, peaking units.

3. The delivery of energy in the "actual" case on an hour-by-hour basis will depart from that assumed in the base case. If more wind energy is delivered at night relative to the reference case, it will be displacing very low cost generation. At the other end of the spectrum, more wind might actually be delivered, again relative to the reference case, during hours where the marginal cost of generation is high. While this is not strictly an "integration cost" related to an ancillary service, the effect is real for the purchaser relative to a predictable and controllable source of energy.

The results presented later will document all of these cost components as an aggregate number.

Model Data and Case

System Data

A temporary license for the ABB Couger v.6.81 unit commitment program was provided by Xcel Energy, along with a "saved-case" database containing all of the input parameters for the present Xcel-NSP control area.

The program database was updated so as to represent the Xcel system as forecast for the year 2010, as described in the Loads and Resources table from the Task 2 section of this report..

The most significant changes for the study year are the planned addition by Xcel Energy of five combustion turbine units with a total capacity of 775 MW, and the conversion of four existing coal-fired units to 954 MW of combined-cycle plant. Assumed heat rate curves were provided by Xcel, and other operating parameters were patterned after a similar unit already in the program database.

As mentioned previously, hourly load data for 2010 was generated by scaling data from the years 2000, 2002, and 2003 such that the peak hour for each of the years matched the projected peak of 9943 MW in 2010.

Wind Generation and Forecast Data

An aggregate hourly wind generation model for the same years was created from the wind resource time-series data as discussed in the report on Task 1. The time series were selected to "line up" with the hour system load time-series so that any correlation between wind generation and system load remained embedded in the data used to drive the unit commitment analysis.

Datasets of power forecast errors for each of the 3 simulation years were generated for the integrated system simulations. This dataset consisted of 365 forecasts of 48 hour length with a power forecast error given for each of the 48 hours. The paradigm for developing the forecast error dataset incorporated the statistical forecast error characteristics from the forecasting evaluation experiment (see Task 1). In this experiment, power was predicted by a computational learning system (CLS) for a 2 day period. The error analysis was derived from a comparison of this CLS forecast with NREL archived production data for the Delta Sector of the Lake Benton 2 Wind Facility in southwest Minnesota. By applying the characteristics of the frequency distribution of the magnitude of forecast power error, a simulated power error forecast was made. This methodology could be described as a random walk to find the error for each additional forecast hour. The size of each random walk step was determined based on random numbers and the forecast experiment delta-error histogram.

To account for the geographic dispersion of the production sites and the autocorrelation between regional wind farms, one forecast error dataset was created for each of 3 regions with separate datasets generated for the 3 years of the system simulation (9 total datasets). A different random seed was used to generate each of the files, insuring their uniqueness. The 3 regional groupings included the southwest Minnesota sites (1-5, 11-30), the southeast Minnesota sites (6-10), and the northeast South Dakota sites (31-50).

A data set corresponding to a next-day hour-by-hour wind generation forecast was created by using the forecast errors for hours 16 through 40 of the forecast data. The result is a 8760-hour time series for each year of the wind model that represents the forecasted wind generation for that hour if the forecast had been made on the morning of the previous day, which is roughly consistent with current practice for next-day scheduling and likely to be appropriate for next day decisions with wholesale energy markets.

Sample time series depicting "forecast" and "actual" wind generation are shown in Figure 62 and Figure 63. The yearly sets of hour 16-40 forecasts were adjusted to make the mean-absolute-error (MAE) for the entire yearly forecast series about 15%. This was done to make the forecast reflective of the current state of the commercial art.

Even with a MAE of 15%, hourly forecast errors can still be substantial. The distribution of hourly errors for the 2003 wind generation forecast and actual time series is shown in Figure 64.

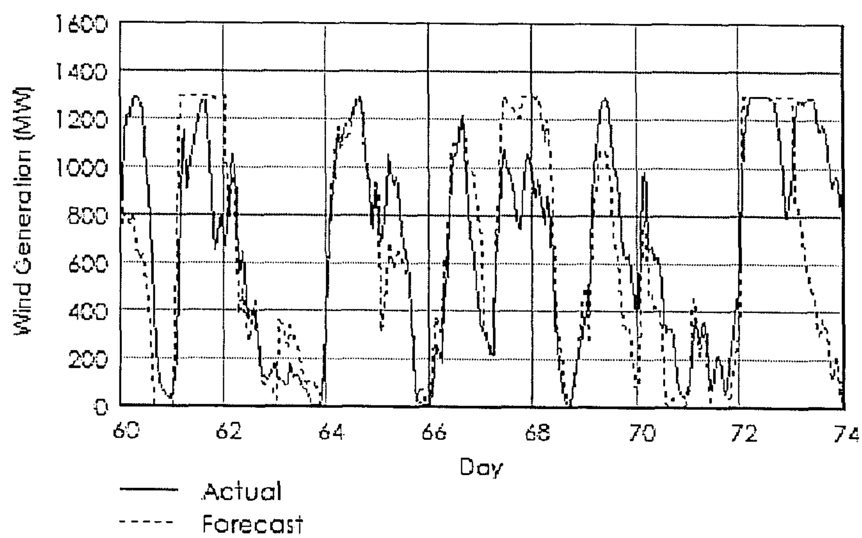


Figure 62: Actual and forecast wind generation for two weeks in March, 2003

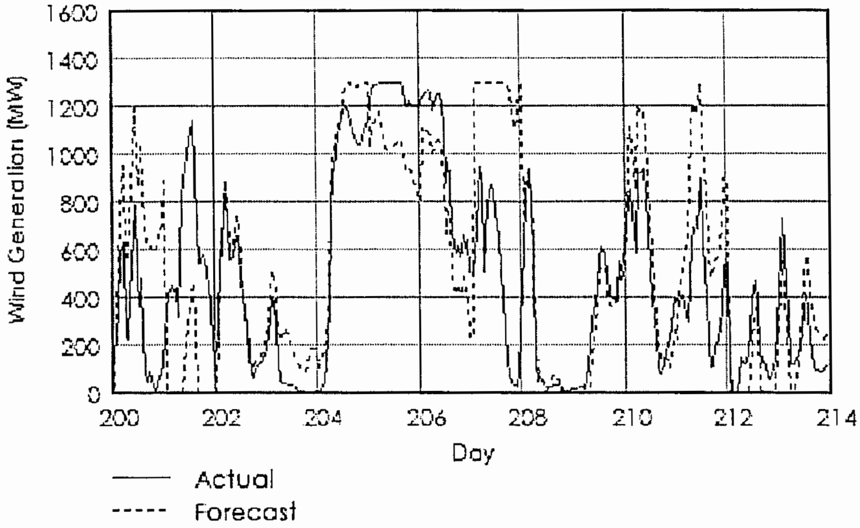


Figure 63: Actual and forecast wind generation for two weeks in July, 2003

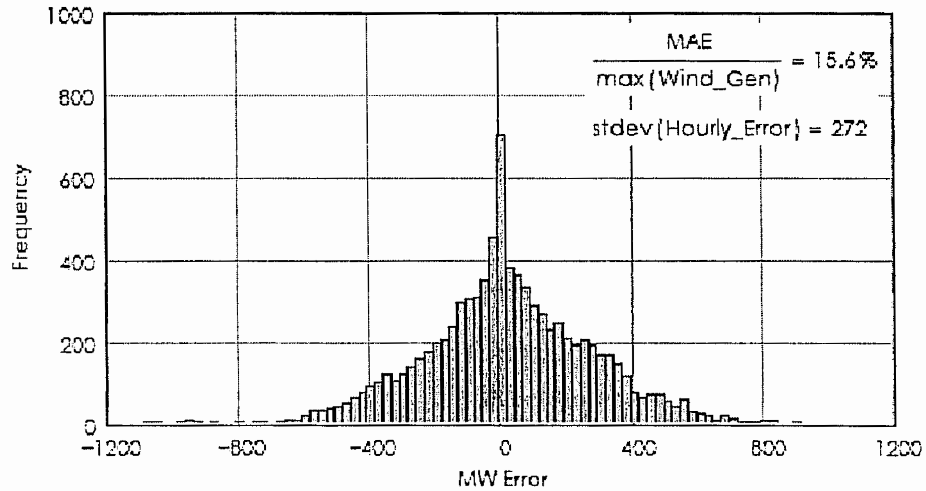


Figure 64: Forecast error statistics for 2003 wind generation time series.

Rationale for the "Reference" Case

As described earlier, the base case for the hourly analysis assumed that the actual wind energy delivered for the day was known exactly, and that it was delivered evenly each hour of the day. Such treatment was chosen for the base case since a flat profile has the minimum impact on ancillary services at the hourly level. Ramping from hour to hour is neither increased nor decreased by flat profile. With respect to production costs, the flat block of energy which shifts the daily load curve downward reduces the need to deploy marginal units during peak periods.

Case Structure

Cases were set up and run for one month at a time, using the actual loads, wind generation, and wind generation forecasts for that month. Because the wind generation forecasts are for 16 to 40 hours forward, and load forecast error is neglected for now, the approach reasonably mimics a day-ahead scheduling process.

Each optimization case requires approximately 30 minutes of computer time to solve. To allow for a large number of days and months to be evaluated (given that two optimization and one simulation case are required for each study period), several assumptions as described in the next section were required.

Assumptions

To allow for analysis of complete years using the methodology described above, it was necessary to develop some assumptions to minimize the changes to the unit commitment program database from case to case. While these assumptions certainly have an influence on production cost, the results sought here are drawn from a comparison of cases, each of which is based on identical assumptions.

It is recognized that the difference in production costs between two case variants may be sensitive to the assumptions made. For practical purposes however, it would not be possible in the context of this study to make scheduling decisions such as those made each day by Xcel operating personnel. The compromise between the scope of the hourly analysis and the precision and accuracy of the assumptions made regarding various aspects of operational flexibility is considered appropriate.

It should also be noted that the assumptions made by the project team and the decisions made automatically by the unit commitment program reflect a realistic if not optimal deployment of the supply resources to meet the forecast load. No unit constraints, as described in the saved case data, were violated, and "unusual" scheduling of units - such as the excessive backing down of base load units" was minimized.

Supply Resources

All of the units in the database were assumed to be available all hours of the year at actual maximum capacity.

Per the results of the regulation analysis, the regulation requirement was assumed to be 70 MW. Reserve requirements (spinning and operating) were not changed from the 2004 data.

Transactions - Internal

The Load and Resources projection for 2010 indicates a number of firm purchases from third parties. For those that already exist in the 2004 unit commitment database, the representation was left as-is. New third-party resources were included as purchase transactions (described below) where firm transmission service had been procured as part of the contract.

Transactions - External

Assumptions about purchases and sales to other control areas were found to be relatively critical to the results. A dispatchable purchase or sale will be used by the unit commitment and economic dispatch logic as compensation for the hourly variations in wind generation if the price is suitably low/high, and will reduce the impact of wind generation on production costs. The purchase and sale definitions in the program setup were adjusted to reasonably reflect the "products" that would be available in a day-ahead market (even for bi-lateral transactions).

Conversations with Xcel operators revealed that in day-ahead scheduling of transactions, the amount of flexibility with respect to significant hour-by-hour variations was limited.

Purchase and Sale "contracts" modeled in the Xcel 2004 Couger database were analyzed, and are shown in Figure 65. Using this as a template, a standard transaction model was developed for this project. A standard model does not provide for probable seasonal changes in transactions or the advantage of shorter-term foresight with respect to system needs. However, it does provide for a reasonable representation that helps to facilitate the execution of a large number of cases for this project. Assumptions for purchases and sales in the 2010 model are shown in Figure 66.

The standard transaction model was broken down into components for modeling in the unit commitment program. On the purchase side, a firm 5x16 contract with Manitoba Hydro for 500 MW was modeled explicitly. The remainder of the purchases were modeled as a flat on-peak and off-peak blocks, as indicated in Figure 67. Sales included a 250 MW 24x7 firm sale and a shaped off-peak sale.

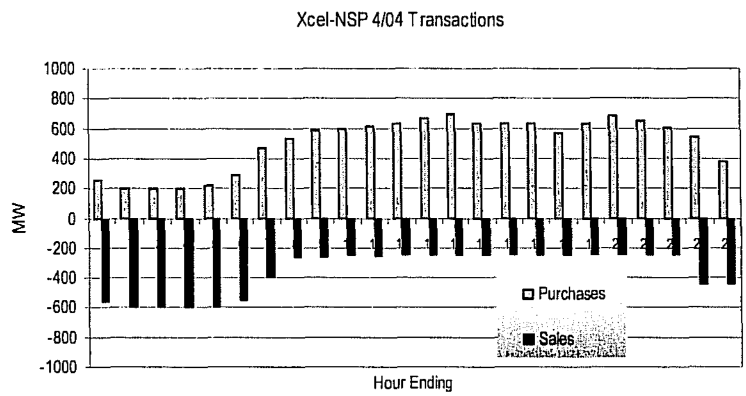


Figure 65: Typical Xcel Energy purchases and sales for Spring '04.

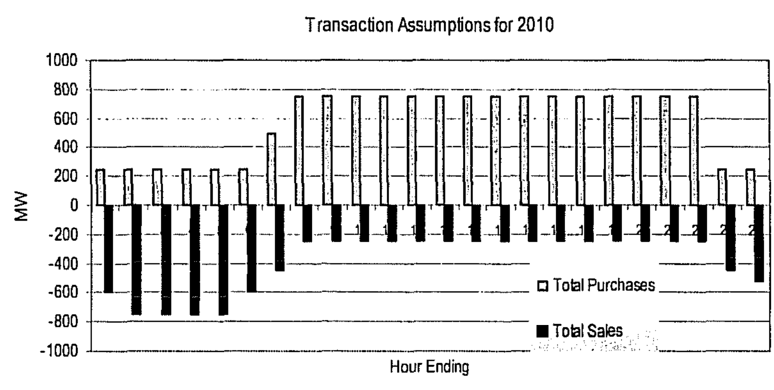


Figure 66: Assumed transactions for 2010 hourly analysis

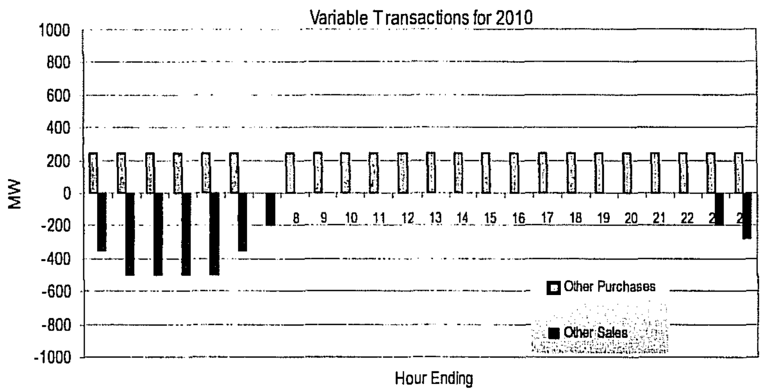


Figure 67: Variable components of 2010 daily purchases and sales (excludes Manitoba Hydro 5x16 contract for 500 MW and forced sale of 250 MW)

Fuel Costs

Minimal adjustments were made to the fuel cost assumptions in the base data provided by Xcel Energy. In effect, the costs and prices are in 2004 dollars.

For the new gas units, a natural gas price of $6.00 /MBTU was assumed.

While it made no difference to the unit commitment or scheduling since it was specified as a "must take" resource, the purchase price for wind energy was assumed to be $29/MWH. The cost of wind energy (and the load served by wind) is subtracted from the production cost summaries so as not to skew the production cost numbers for the other Xcel resources.

Results

Results of the hourly analysis for one year of study data are shown in Table 20 and 21.

Notes on the Table:

- **Base Production Cost** is the total cost incurred by Xcel Energy to serve the load not served by wind generation in the base case, where an equal amount of wind energy is delivered as a flat block over the day.
- **Actual Production Cost** is the total cost incurred by Xcel Energy to serve the load not served by wind generation where the unit commitment and day-ahead schedule are developed with an hour-by-hour forecast of wind generation for the next day.
- **Net Load Served** is the amount of load served by Xcel Energy resources – it does not include the load served by wind generation.
- **Unserved by DA (Day-Ahead) Plan** is the energy that could not be served by the unit commitment and schedule developed with the wind generation forecast. This load is not really "unserved", as resources would be acquired on the day or the hour before, presumably at a higher cost that if they could have been procured in day-ahead arrangements.
- **HA (Hour-Ahead) Energy Price** is the assumed cost per MWH to provide for the load unserved by the DA plan.

- **Wind Generation** is the actual wind energy delivered over the course of the study period (month)
- **Incr. Prod. Cost** is the cost difference, in thousands of dollars, between the base plan and the actual production cost from the simulation run.
- **HA Energy Cost** is the assumed total cost of energy in the current day or hour ahead markets to serve the load unserved by the day-ahead plan.
- **Hourly Integration Cost** is the sum of the increased production cost plus the hour-ahead energy cost divided by the total wind energy delivered over the period.
- **Load served by Wind** is the fraction of the total energy demand over the study period that was provided from wind generation.

Discussion

From the hourly simulations, the cost to Xcel Energy for integrating 1500 MW of nameplate wind generation capacity is estimated to be $4.37/MWH of wind generation delivered to the system. This number is the total of the incremental production and hour-ahead energy costs divided by the total amount of wind energy delivered to the system over the 24 months studied.

Based on conversations with Xcel Energy operating personnel, the production cost results in the table are higher than those now incurred for the Xcel-NSP control area. The previously discussed assumptions made to facilitate the execution of a large number of cases at a granularity of one month are certainly a factor. However, the planned changes to the resource portfolio for the study year were also cited as having some potential impact.

The monthly variability of the integration cost also stands out. In some respects, this variation seems reasonable since during the months with higher loads, more expensive generation is being called upon more frequently. This rationale does not explain, however some higher integration costs during the winter, when the load would be modest but not high.

Some of the higher integration costs during the two summer months can actually be attributed to the relatively low wind energy production during those periods. Note that while the differential production cost is high for those months, it is actually higher in December and about the same in April. Those summer months are the worst and third worst in terms of wind energy production, however.

Another factor to consider is the wind generation forecast accuracy. These cases utilize a wind generation forecast with a realistically random error. It is possible that a variation in forecast quality between the monthly cases might be responsible for the variation. Investigation of this aspect is outside the scope of this study, unfortunately. However, when results for the remaining twenty four months of the load and wind data are -considered in the aggregate, the effect of statistical variations in forecast accuracy should be reduced.

Table 20: Results of Hourly Analysis for First Annual Data Set (2003 Wind Generation & 2003 Load Scaled to 2010).

	Average Base Prod. Cost ($/MWH)	Average Actual Prod. Cost ($/MWH)	Net Load Served (MWH)	Unserved by DA Plan (MWH)	HA Energy Price (per MWH)	Wind Generation (MWH)	Incr. Prod. Cost (k$)	HA Energy Cost (k$)	Hourly Integration Cost ($/MWH)	Load served by Wind (% of Total)
January	$17.55	$18.07	3,765,189	0	$50.00	465,448	$1,949	$0	$4.19	11.0%
February	$16.52	$16.99	3,295,060	6256	$50.00	472,998	$1,560	$313	$3.96	12.6%
March	$16.33	$16.65	3,417,066	1876	$50.00	491,883	$1,104	$94	$2.43	12.6%
April	$15.91	$16.73	3,139,152	2355	$50.00	485,379	$2,564	$118	$5.52	13.4%
May	$16.64	$16.92	3,294,088	4793	$50.00	400,220	$916	$240	$2.89	10.8%
June	$18.81	$19.06	3,699,027	4526	$50.00	316,798	$930	$226	$3.65	7.9%
July	$20.65	$21.41	4,246,909	2884	$50.00	427,006	$3,228	$144	$7.90	9.1%
August	$22.54	$23.20	4,546,729	6640	$50.00	301,811	$2,992	$332	$11.01	6.2%
September	$17.62	$17.96	3,434,343	10781	$50.00	516,199	$1,151	$539	$3.27	13.1%
October	$16.17	$16.64	3,382,287	1266	$50.00	478,654	$1,607	$63	$3.49	12.4%
November	$15.75	$16.22	3,180,262	2976	$50.00	602,016	$1,499	$149	$2.74	15.9%
December	$16.80	$18.00	3,508,015	0	$50.00	625,926	$4,186	$0	$6.69	15.1%
Annual Total	$17.83	$18.38	42,908,126	44,353		5,584,338	$23,686	$2,218	$4.64	11.5%

Table 21: Results of Hourly Analysis for Second Annual Data Set (2002 Wind Generation & 2002 Load Scaled to 2010)

	Average Base Prod. Cost ($/MWH)	Average Actual Prod. Cost ($/MWH)	Net Load Served (MWH)	Unserved by DA Plan (MWH)	HA Energy Price (per MWH)	Wind Generation (MWH)	Incr. Prod. Cost (k$)	HA Energy Cost (k$)	Hourly Integration Cost ($/MWH)	Load served by Wind (% of Total)
January	$16.90	$17.47	3,476,721	158	$50.00	532,870	$2,003	$8	$3.77	13.3%
February	$15.78	$16.27	2,917,429	2771	$50.00	581,258	$1,431	$139	$2.70	16.6%
March	$15.94	$16.42	3,416,137	1783	$50.00	511,552	$1,618	$89	$3.34	13.0%
April	$17.87	$18.38	3,122,346	1691	$50.00	501,014	$1,579	$85	$3.32	13.8%
May	$16.67	$16.86	3,240,090	3202	$50.00	465,686	$604	$160	$1.64	12.6%
June	$19.52	$19.57	3,824,551	14975	$50.00	509,564	$198	$749	$1.86	11.8%
July	$23.35	$24.32	4,574,548	8514	$50.00	411,140	$4,416	$426	$11.78	8.2%
August	$19.03	$19.47	3,982,906	5526	$50.00	430,083	$1,732	$276	$4.67	9.7%
September	$18.21	$18.85	3,569,729	3240	$50.00	485,658	$2,260	$162	$4.99	12.0%
October	$16.41	$16.99	3,447,750	7243	$50.00	395,261	$1,997	$362	$5.97	10.3%
November	$16.02	$16.41	3,295,648	1523	$50.00	435,350	$1,309	$76	$3.18	11.7%
December	$16.55	$17.03	3,494,610	5977	$50.00	507,473	$1,699	$299	$3.94	12.7%
Annual Total	$17.91	$18.40	42,362,464	56,603		5,766,909	$20,846	$2,830	$4.11	12.0%

Table 22: Production Cost Comparison for Base, Forecast, and Actual Cases

		Base			Forecast			Actual		
		Net Load Served (MWH)	Prod. Cost ($/MWH)	Wind Generation (MWH)	Net Load Served (MWH)	Prod. Cost ($/MWH)	Wind Generation (MWH)	Net Load Served (MWH)	Prod. Cost ($/MWH)	Wind Generation (MWH)
2002	January	3,517,149	$16.90	492,600	3,517,159	$17.48	492,590	3,476,721	$17.47	532,870
	February	2,930,801	$15.78	570,576	2,930,898	$16.09	570,479	2,917,429	$16.27	581,258
	March	3,470,376	$15.94	459,096	3,470,400	$16.33	459,072	3,416,137	$16.42	511,552
	April	3,098,927	$17.87	524,544	3,102,000	$18.51	524,540	3,122,346	$18.38	501,014
	May	3,262,070	$16.67	443,928	3,262,126	$17.33	443,872	3,240,090	$16.86	465,686
	June	3,838,538	$19.52	510,552	3,838,574	$19.70	510,516	3,824,551	$19.57	509,564
	July	4,562,796	$23.35	430,992	4,561,149	$24.22	430,964	4,574,548	$24.32	411,140
	August	3,998,107	$19.03	420,408	3,998,085	$19.42	420,430	3,982,906	$19.47	430,083
	September	3,651,945	$18.21	406,536	3,651,931	$18.78	406,550	3,569,729	$18.85	485,658
	October	3,421,791	$16.41	427,872	3,421,754	$16.72	427,908	3,447,750	$16.99	395,261
	November	3,303,449	$16.02	429,072	3,303,439	$16.37	429,082	3,295,648	$16.41	435,350
	December	3,489,660	$16.55	518,400	3,489,629	$16.86	518,431	3,494,610	$17.03	507,473
2003	January	3,767,713	$17.55	465,456	3,817,316	$17.99	415,853	3,765,189	$18.07	465,448
	February	3,301,370	$16.52	472,944	3,332,413	$16.85	441,901	3,295,060	$16.99	473,000
	March	3,418,764	$16.33	491,928	3,451,085	$16.59	459,607	3,417,066	$16.65	491,883
	April	3,141,284	$15.91	485,400	3,111,779	$16.74	514,905	3,139,152	$16.73	485,379
	May	3,311,178	$16.64	387,048	3,293,012	$16.84	405,213	3,294,088	$16.92	400,220
	June	3,725,285	$18.81	294,792	3,693,451	$19.00	326,625	3,699,027	$19.06	316,798
	July	4,249,863	$20.65	426,936	4,235,709	$21.46	441,090	4,246,909	$21.41	427,006
	August	4,544,788	$22.54	310,392	4,527,186	$23.07	327,994	4,546,729	$23.20	301,811
	September	3,444,983	$17.62	516,192	3,398,835	$17.78	562,340	3,434,343	$17.96	516,199
	October	3,383,279	$16.17	478,680	3,389,446	$16.64	472,513	3,382,287	$16.64	478,654
	November	3,180,262	$15.75	602,016	3,191,247	$16.21	591,031	3,177,280	$16.22	602,022
	December	3,502,057	$16.80	631,440	3,599,905	$17.88	533,591	3,508,015	$18.00	625,926

Load Forecast Accuracy Issues

Day-ahead generation planning and scheduling, even without wind generation in the control area, is based on forecasts. A projection of the control area load on an hour-by-hour basis for the next day or days is the most important input to the planning process and analytical algorithms for determining the lowest cost operating plan.

All forecasts contain at least some error, which for the preceding hourly analysis raises the question of the relative importance of the wind generation forecast error versus the error in forecasts for hourly load. Reference [15] provides an interesting analysis of the economic impact of load forecasting accuracy for a sample power system, using an analytical methodology that is similar to that employed in this study. The conclusions of that report are of interest in the context of the current study:

- Cost impacts due to load forecasting errors are small if hourly load forecasts are within 5% of the actual value. As the error increases beyond this value for the generic system considered, the economic consequences increase substantially.
- The greatest benefit in terms of reducing the economic impact of load forecast errors comes from increasing the accuracy of the daily peak load forecast.

Results from a recent study of peak load forecasting accuracy by Xcel Energy are shown in Table 23. These particular results are for a more advanced load forecasting model that apparently utilizes an embedded weather model.

Table 23: Day-Ahead Peak Load Forecast Accuracy from internal Xcel Study

Month	Mean Absolute Peak Error (MW)	Percentage of Peak	Std. Dev.
September	77	0.77%	0.24%
October	102	1.02%	1.29%
November	67	0.67%	0.16%
December	72	0.72%	0.26%
January	69	0.69%	0.21%
February	66	0.66%	0.19%

Extrapolating that performance to the study year, the expected error in the peak and hourly load forecasts will be on the order of 50 to 100 MW for daily peak loads between 5000 and 10000 MW. To facilitate comparison with hourly wind generation forecast errors, statistics from Table 23 were used to generate a synthetic forecast load data set.

For each day of the hourly loads from the scaled 2003 data set, a forecast series was generated. A normally-distributed random error was created and applied to the actual load values by two different methods:

- The random forecast error percentage was generated for each hour of the day and multiplied by the daily peak load value. The resulting value was then added to the actual load value for each hour of the day and for each day of the year.

- A forecast error in MW was calculated as the product of the random error percentage and the daily peak load. This error was then applied uniformly to each hourly value for the day.

The first method results in a daily load forecast that exhibits random variations about some smoother daily load pattern. The second method produces a forecast that is either lower or higher for the entire day. (Results from both methods are shown in Figure 68.)

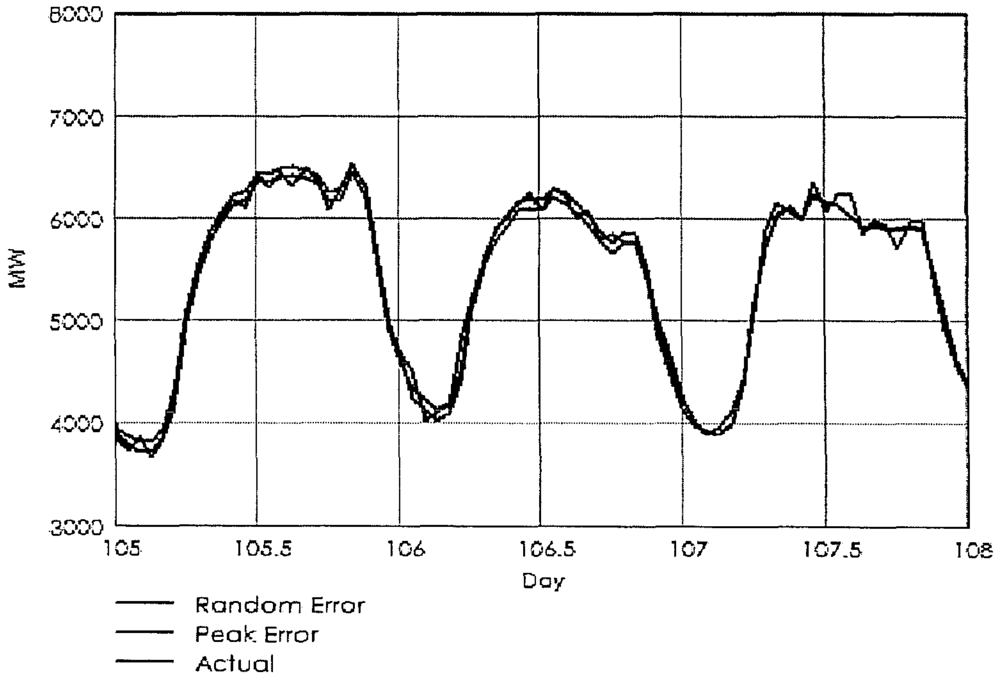


Figure 68: Load forecast series developed with Xcel load forecast accuracy statistics.

The second method produces a load forecast that may be more realistic since actual load forecasting would utilize peak load forecasts along with appropriate daily patterns drawn from historical data. The historical patterns would not contain random deviations from hour to hour, but instead reflect the smoother behavior of the aggregate load as it transitions through a characteristic daily pattern.

The distribution of hourly forecast errors for both load forecast time series is shown in Figure 69. The distribution from the daily error or peak load forecast error is lumpier since there are only 365 samples from the forecast error distribution. The error in each hour with the first method constitutes a "draw" from the statistical sample, so the distribution is correspondingly smoother.

For both load forecast time series, the Mean Absolute Peak Error is just over 1%, with a standard deviation of about 0.84%. These statistics are on the high end for both the mean and standard deviation as per Table 23.

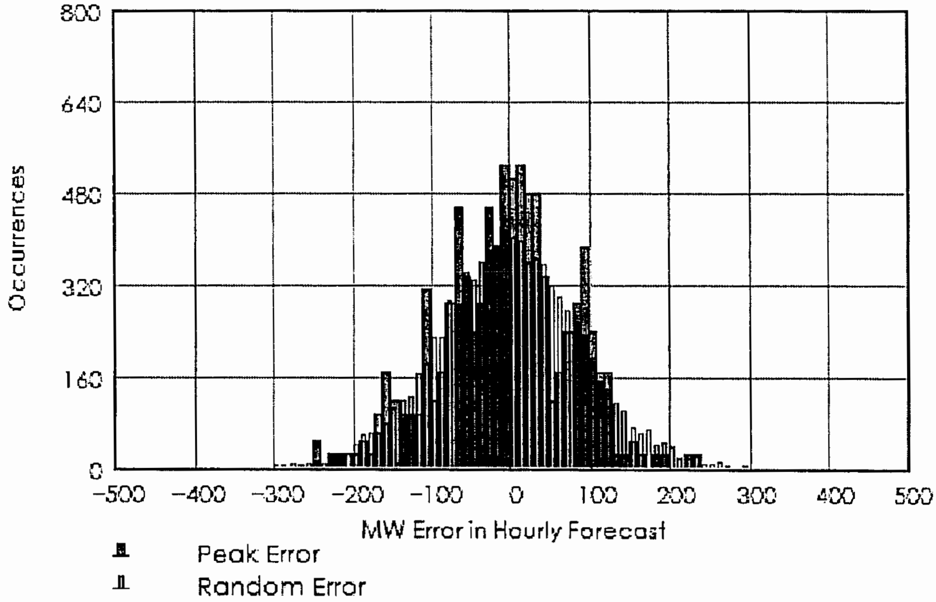


Figure 69: Distribution of hourly load forecast errors for the load forecast synthesis methods.

The corresponding distribution for the wind generation forecast errors is shown in Figure 70. Note that the horizontal axis is expanded for this distribution. Also notable is the rather large standard deviation of 272 MW for wind generation forecast error. The hourly wind generation forecast errors that contribute to this large standard deviation likely result from inaccurate projections of the timing of significant changes in wind generation.

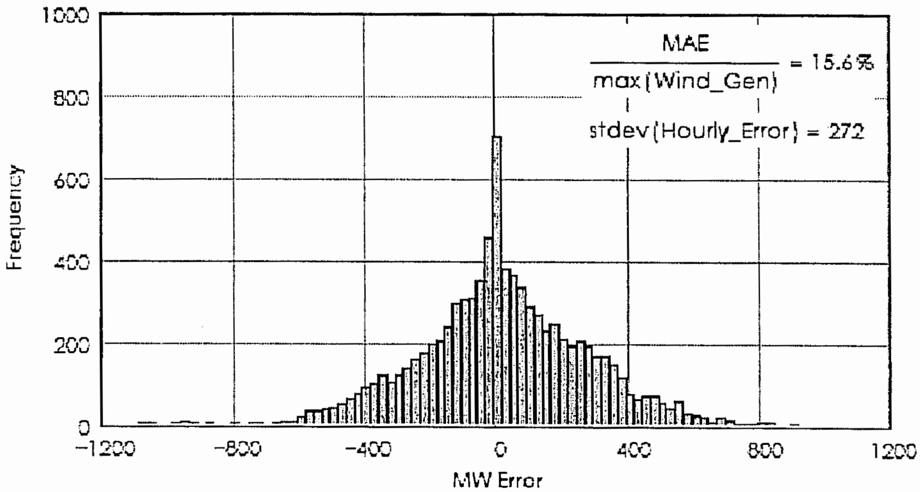


Figure 70: Forecast error statistics for 2003 wind generation time series.

The effect of the wind generation forecast errors on the total hourly error in the day-ahead forecast of net control area demand is found by combining the load and wind generation forecasts and subtracting the result from the actual load minus wind generation for each hour of the year. Figure 71 shows the distribution of hourly errors for the load only and for the combination of load and wind generation.

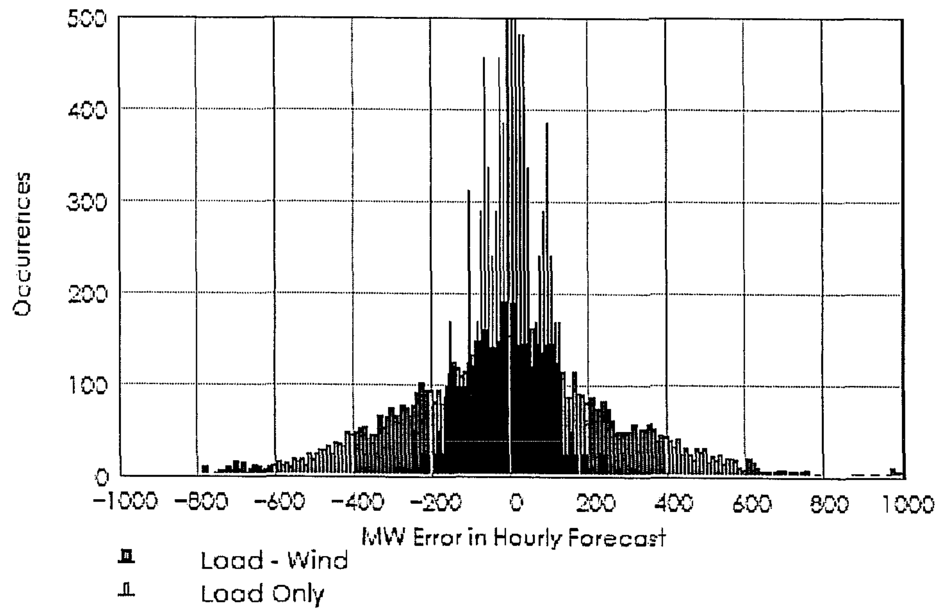


Figure 71: Hourly forecast error distribution for load only and load with wind.

For the load alone, there are less than 200 hours over the year where the hourly error is in excess of +/-200 MW. With wind generation added, that number increases to almost 3900 hours. In terms of statistics, the standard deviation of the hourly load forecast errors is 81 MW, and 272 MW for the hourly wind generation forecast errors. The standard deviation of load with wind generation is 281 MW.

Neglecting load forecast errors in the hourly analysis likely overstates the calculated hourly integration costs somewhat. In some instances, the wind generation and load forecast errors will be compensating, and at other times lead to higher net hourly forecast errors. The preceding analysis shows, however, that in the scenario for this study, wind generation forecast errors are major factor in hourly forecast uncertainty. In addition, errors in wind generation forecast are solely responsible for the very large hourly errors. These large hourly deviations from the plan are of significance with regard to control area performance, and may contribute disproportionately to integration costs at the hourly level.

MISO Market Considerations

In earlier discussion, the effect of external markets on the production cost impacts was mentioned. How the nature of these markets could impact the hourly integration costs is illustrated here.

Increased production costs result in part from the commitment and scheduling of additional resources to compensate for the forecast variations in wind generation that do not follow, and may run counter to, the daily load curve. When the forecasts of this variability are in error, additional costs are incurred. Because wind generation forecast accuracy degrades significantly with time, day-ahead forecasts will always be less accurate than those for an hour or a few hours ahead.

The situation may be one, then, of making a decision a day ahead that ends up costing significantly if the information upon which that decision is based is not of sufficient accuracy. The availability of liquid and competitive hour-ahead markets could dramatically alter how the operators plan to handle the variability of wind generation. Rather than making a day-ahead decision with uncertain information that will have negative economic consequences if it turns out wrong, the decision can be deferred to a time when the accuracy of the information (i.e. wind generation forecast) is much better. While the hour-ahead adjustment may be more costly, the "win" probability over a longer period may be higher.

Planning studies conducted by MISO for the year 2007 indicate that energy supply is plentiful in the upper Midwest, and projected locational marginal prices (LMPs) relevant to this study range from roughly $10 to $20 per MWH. The upper range is seen in the peak load months and hours, with minimum prices during the shoulder seasons. Costs incurred by Xcel to integrate wind generation could presumably be reduced by utilizing liquid and flexible day-ahead and hour-ahead purchases and sales to compensate for the variability in wind generation, as an alternative to more expensive internal resources. The results of the hourly analysis presented previously seem to indicate that the integration costs are higher during the highest load months, when more expensive marginal units are being dispatched around the variable wind generation.

The analytical methodology used to generate the hourly results was adapted to assess how use of energy markets rather than internal resources would impact integration costs. Three of the 2003 monthly cases - January, May, and August - were re-run with the addition of dispatchable market purchase and sale transactions. A maximum limit of 500 MW was assumed for both purchase and sale. The purchase and sale prices in the day-ahead market were assumed to be $25/MWH and $20/MWH respectively, constant for each hour of the day and each month selected for evaluation.

The new market transactions were added to the "Base" case, and the unit commit program was run to develop a minimum cost plan. In the "Forecast" case, the unit commitment program was allowed to commit and dispatch all resources, including the market transactions, against a forecast of wind generation and load. The resulting market transactions are then considered as obligations assumed in the day-ahead energy market.

For the "Actual" case, the program was restricted to dispatching only the resources committed in the "Forecast" case, but was allowed to re-dispatch all available units as well as the new market transactions. The resulting hourly transactions for the market purchase and sale then reflects the sum of the day-ahead obligations and purchases and sales in the hour-ahead market. An assumption here is that wind generation predictions for the next hour are perfect.

The hour-ahead market transactions can then be calculated as the difference between the actual purchases and sales and the day-ahead market obligations. As was the situation in the hourly cases presented previously, there are hours in the "Actual" case where unit operating restrictions lead to "unserved" energy. This energy was deducted from the computed hour-ahead market sales.

Figure 72 shows the day-ahead scheduled transactions and the actual transactions for the January case. The hourly difference, representing the assumed hour-ahead transactions, is shown in Figure 73.

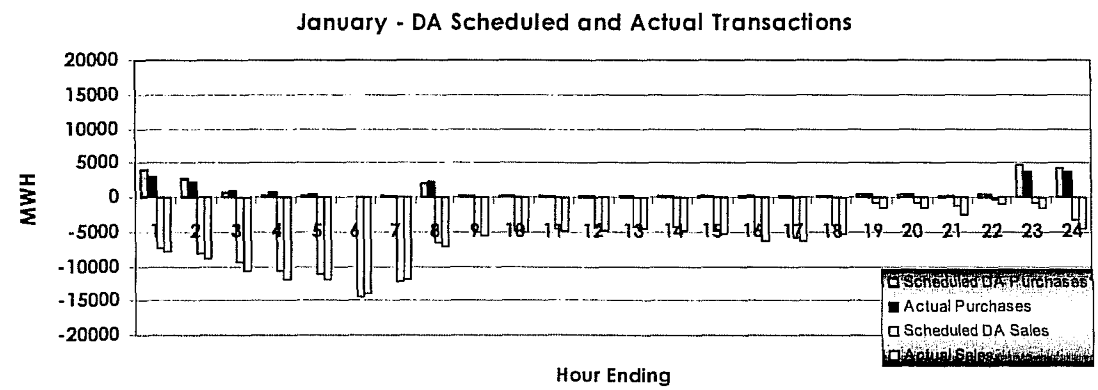


Figure 72: Day-ahead scheduled and actual transactions for January market simulation case.

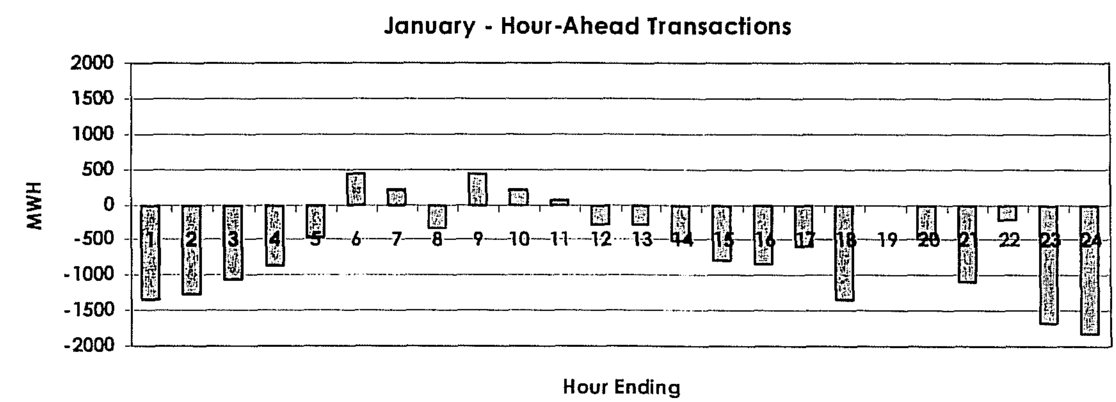


Figure 73: Assumed hour-ahead transactions for the January case.

Results for the market simulation cases are shown in Table 24. Price histories are not available for the MISO day-ahead and hour-ahead markets, so an assumption was made that the hour-ahead transactions incurred a $10/MWH premium over the day-ahead prices, for both purchases and sales. As that premium declines, the HA costs in the table would decline correspondingly.

The introduction of flexible market transactions to assist with balancing wind generation in both the day-ahead scheduling process and on the day one hour ahead has a dramatic impact on integration costs at the hourly level in the highest cost month (August, in this case). During the lowest load month of the three (May), the effect is minimal; in fact, the premium for the hour-ahead transactions actually results in a slight increase in integration cost. Under these conditions, schedulers could decide to utilize internal resources instead of risking higher costs in the market, so this premium could likely be avoided. In January, where the load is higher than May and wind generation is higher than August, the effect is more modest, but still represents a 25% decrease in integration cost.

Table 24: Results of Hourly Cases with Energy Market Assumptions

	Base Prod. Cost (k$)	Actual Prod. Cost k$)	Net Load Served (MWH)	Wind Generation (MWH)	Incr. Prod. Cost (k$)	HA Energy Cost (k$)	Hourly Integration Cost ($/MWH)	Difference ($/MWH)
January	$64,496.62	$65,722.79	3765735	465448	$1,226.17	$167.19	$2.99	$1.19
May	$50,771.83	$51,915.91	3294009	400220	$1,144.08	$169.34	$3.28	-$0.40
August	$100,773.31	$101,663.77	4534751	310401	$890.46	$156.23	$3.37	$7.64

The results are consistent with the notion that the system load level affects the units that would be committed and dispatched to accommodate the variability in wind generation. During the high load months, when expensive marginal units are committed and dispatched to accommodate the variability in wind generation, flexible and less expensive market purchases can dramatically reduce integration costs. At other times, when wind generation is accommodated with less expensive units, the impact is less pronounced.

Intra-Hourly Impacts

Background

The probable impacts of wind generation on the generation ramping requirements from hour to hour was addressed in the previous sections, with the conclusion being that the analytical methodology at the hourly level captures the costs of the increased ramping burden on the Xcel system due to wind generation.

In this section, what happens on smaller time scales, within the hour, will be assessed.

The base data for the analysis consisted of multiple years of Xcel control area load data archived at 5 minute resolution and synthesized wind generation data at 10 minute intervals for overlapping years derived from the WindLogics meteorological simulations.

Data Analysis

One year of data corresponding to most of the calendar year 2003 was analyzed. The 2003 load data was scaled so that the peak hour matches that peak demand of 9933 MW forecast for 2010. The scaled load data and the net of the load data minus the wind generation is shown in Figure 74 at 10 minute intervals for 8000 hours.

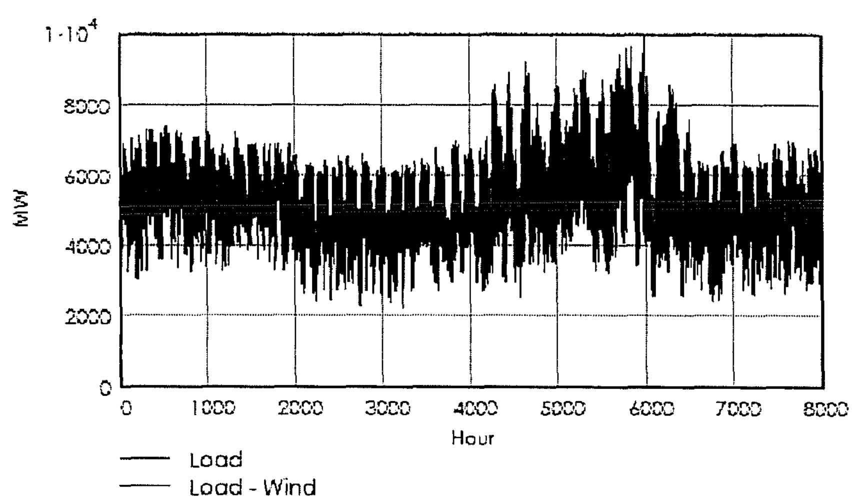


Figure 74: High resolution load and wind generation data.

Within the hour, Xcel generating resources are controlled by the EMS to follow the changes in the load. Some of these changes can be categorized as "regulation", which was analyzed in a previous section. Others, however, are of longer duration and reflect the underlying trends in the load - ramping up in the morning and down late in the day. Still others could be due to longer-term variations about general load trend with time. The nature of these changes can be simply quantified by looking at the MW change in load value from one ten minute interval to the next. Figure 75 contains a time series of the load changes on a ten minute basis for the entire data set analyzed here.

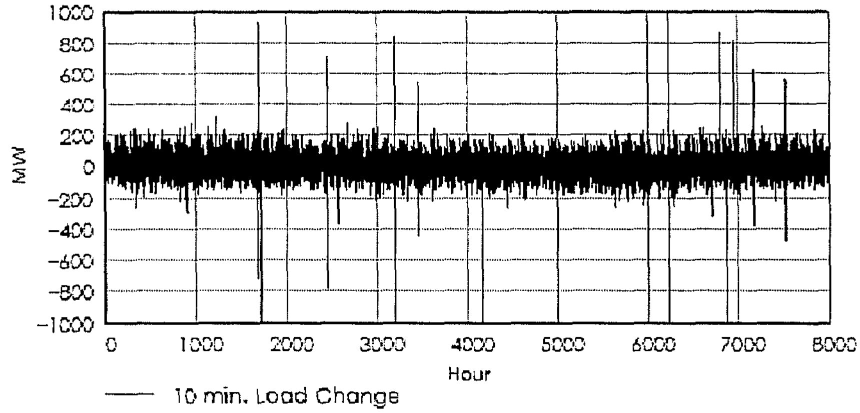


Figure 75: Changes in system load at ten minute intervals.

Most of the changes are within a +/- 200 MW band. The large deviations were analyzed, and some are thought to be events where large blocks of load were lost; others are due to data quality issues. The total number of these large excursions is negligible with respect to the number of samples in the set (about 50,000).

A similar algorithm was applied to the synthesized high-resolution wind generation data, with the result shown in Figure 76. While a large percentage of the fast excursions are confined to a very narrow band, a significant increase in the number of large excursions is apparent.

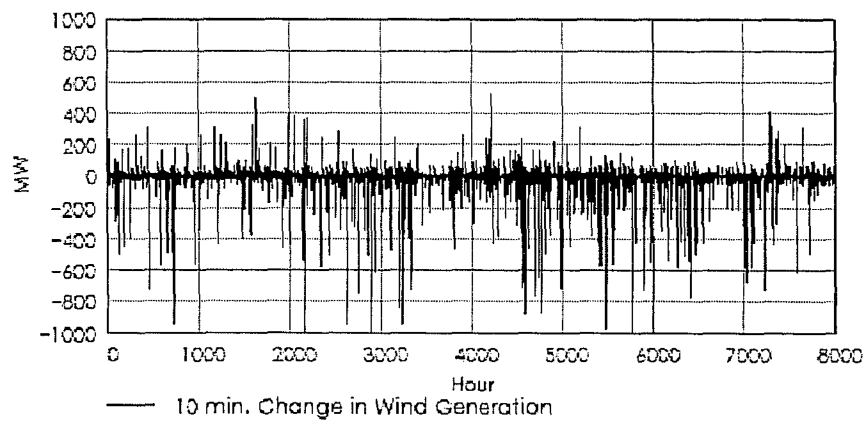


Figure 76: Ten-minute changes in wind generation from synthesized high-resolution wind generation data.

Closer inspection of the high-resolution wind generation data set revealed short data gaps at the beginning of each month. These gaps are an artifact of the meteorological model runs and initialization process. Consequently, in the figure above, there are twenty-four ten-minute change values that are spurious. A few of these are readily identifiable in the graph above as the most extreme ten minute changes. Of the twenty-four spurious samples, nine of them resulted in ten minute changes greater than 400 MW. Because these artificial changes were not identified until the analysis was nearly complete, they do appear in the statistics. Since the total number is very small relative to the total number in the sample, the results and conclusions of the analysis are not affected.

A comparison of the fast changes in system load and aggregate wind generation is shown in Figure 77 for a one week period in the sample data sets. Positive and negative load trends can be identified as extended periods above or below the zero line; sudden and significant changes in wind generation appear as "spikes". The plot seems to indicate that the volatility of the system load at ten minute intervals is significantly higher than for the aggregate wind generation.

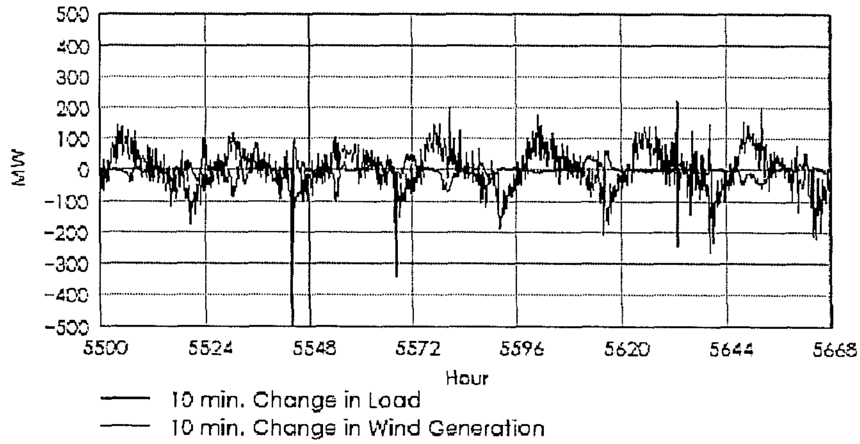


Figure 77: System load and aggregate wind generation changes for a one week period.

Because of the large number of points in each time series, a statistical characterization is helpful for developing an overall quantification. The distribution of the system load changes on a ten minute basis over the entire 8000 hours of the data set is shown in Figure 78. Almost all of the changes are less than 200 MW in magnitude.

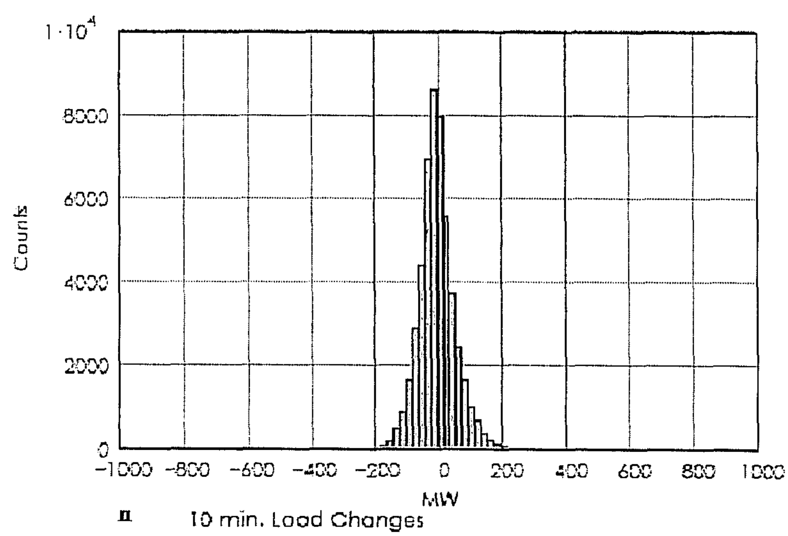


Figure 78: Distribution of 10 minute changes in system load.

Figure 79 contains a similar representation for the ten minute changes in wind generation; most of these changes are less than 100 MW.

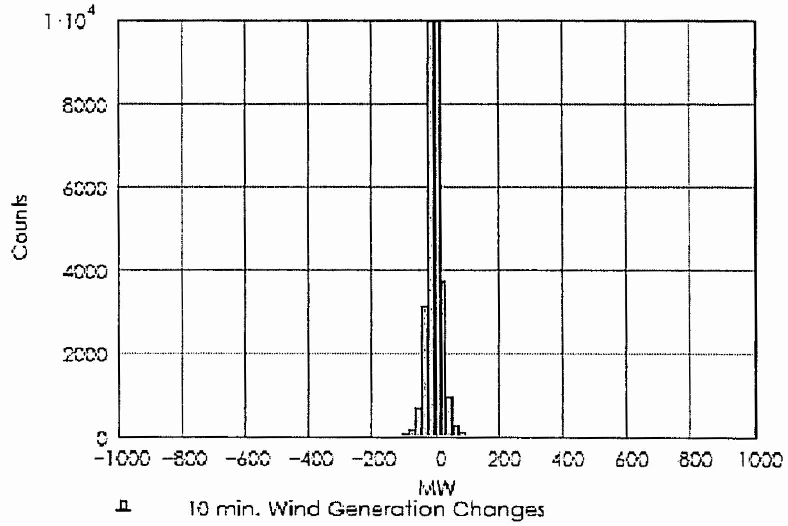


Figure 79: Distribution of 10 minute changes in aggregate wind generation.

From the system control perspective, the net of system load and wind generation is what is of most interest. A time series was constructed from the original load and wind generation data, and then processed to assess the impact of wind generation on the net control area demand change on a ten minute interval. Figure 80 contains two distributions overlaid. The most visible on the figure is the original distribution of changes in the load only, as shown in Figure 78 above. The second distribution is just visible at the edges, indicating only a slight impact on the magnitude of the fast changes to which the EMS and AGC systems must respond.

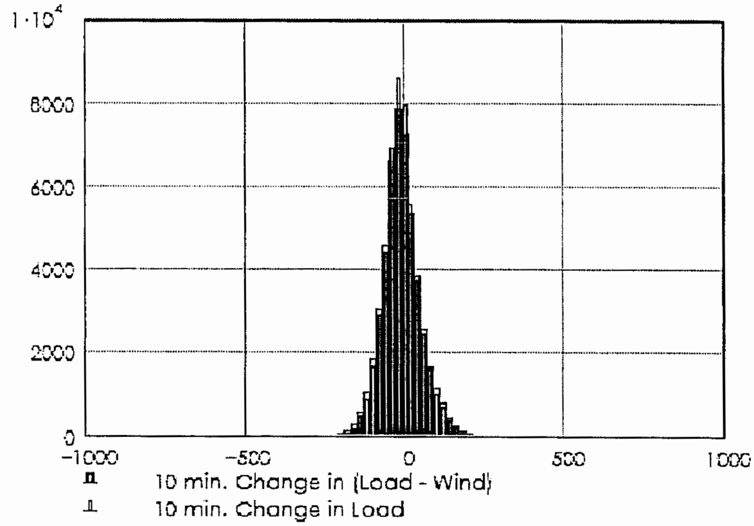


Figure 80: Control area net load changes on ten minute intervals with and without wind generation.

Figure 81 expands the view of the two distributions to better reveal the impact of the aggregate wind generation. The increase in the number of changes of larger magnitude is visible from the figure, along with some more extreme "tail" events.

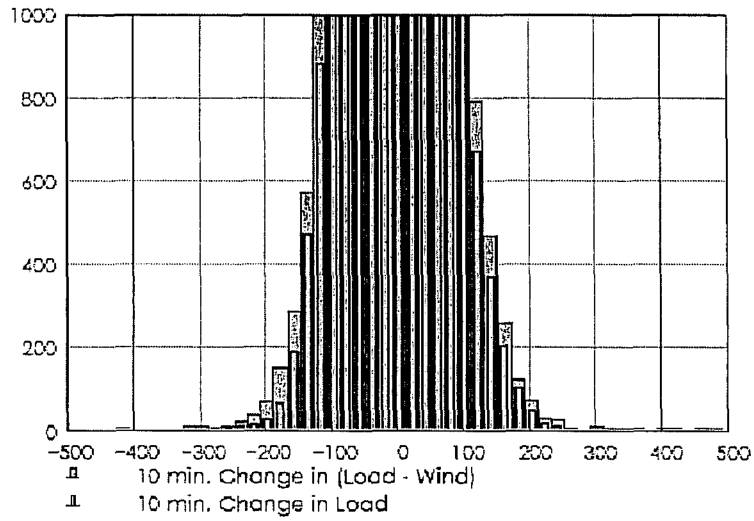


Figure 81: Expanded view of Figure 80.

Statistics for the two distributions are shown in Table 25. The standard deviation of the changes in control area net demand are increased slightly, by about 10 MW, with the addition of 1500 MW of wind generation.

Table 25: Statistics of Ten-Minute Changes

Quantity	Mean (MW)	Standard Deviation (MW)
System Load	0	59.7
Aggregate Wind Generation	0	33.4
Load - Wind	0	69.0

It is interesting to note that the standard deviation of the system load and wind generation combination is nearly equal to the root of the sum of the squares of the standard deviations of the system load and wind generation distributions by themselves, indicating that the changes are nearly uncorrelated.

The data analysis here indicates that the addition of 1500 MW of wind generation to the Xcel system load has only a slight impact on the magnitude of changes in the net control area demand within the hour. The standard deviation of all of the ten minute changes in the data series of 50000 such occurrences is increased by only 10 MW.

Discussion

An objective of this study was to determine the "energy impacts of following the ramping and fluctuation of the wind generation in the load following time frame."

Energy impacts would stem from non-optimal dispatch of units relegated to follow load as it changes within the hour. The faster fluctuations up and down about a longer term trend, determine the regulation requirements as discussed before. These fluctuations were defined to be energy neutral - i.e. integrated energy over a period is zero. The energy impacts on the load following time frame thus do not include the regulation variations, but are driven by longer term deviations of the control area demand from an even longer term trend. Additional production costs (compared with those calculated on an hourly basis, for control area load that remains constant for the hour) result from the load following units dispatched to different and possibly non-optimal operating levels to track the load variation through the hour.

The additional costs of this type attributable to wind generation are related, then, to how it alters the intra-hourly characteristic of the net control area demand. The analysis in the previous section focused on the absolute changes in system load with and without wind generation on ten minute intervals. The results show that wind generation would increase the intra-hourly variability only slightly. Because the statistics were drawn from changes from one ten minute interval to the next, the variations cannot be segregated from those that would occur if the control area demand were smoothly transitioning from one hour-ending value to the next.

Another approach for characterizing the intra-hourly variations not classified as regulation would be to compare the ten minute data to a trend derived from the hourly average load. A long-term trend characteristic for system load with and without wind generation was created by calculating the average of the ten minute data over a two hour rolling window. The results for one 12-hour period are shown in Figure 82.

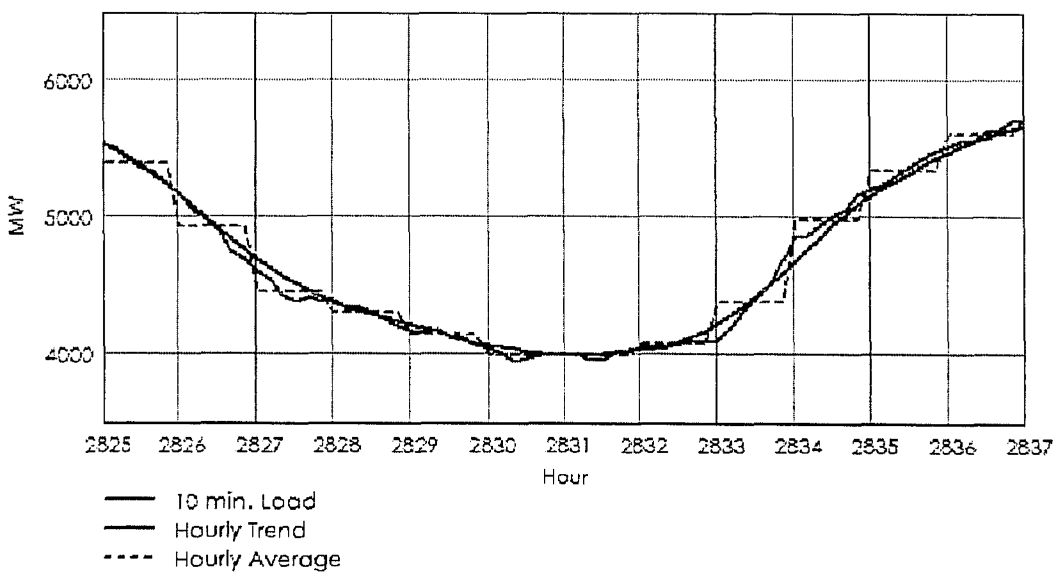


Figure 82: 12-hour load time series showing high-resolution data (red), hourly trend (blue), and hourly average value (magenta).

The hourly trend curve represents load characteristic that would impose a minimum burden and cost for load following, since the changes are smooth and track the hourly values for which the generation schedule was optimized. Deviations of the actual load from this curve mean that generation must be raised or lowered to avoid a control performance violation. In most cases, a prospective control performance violation would take precedence over a short-term non-optimal dispatch, resulting in an incremental production cost.

While somewhat of an artificial construct, this formulation provides a useful baseline for understanding the impact of wind generation on intra-hourly load following requirements. It is similar to the method used for separating the regulation characteristics from the load trend. The approach involves calculating the deviations of the actual control area demand from the hourly trend curve. A comparison of the deviations will then shed light on the likely difference in the intra-hourly burden for maintaining control performance and the possible increases in intra-hourly production cost when wind generation is added to the mix.

Results of this calculation for the system load with and without wind generation are shown in Figure 83 with an expanded view in Figure 84.

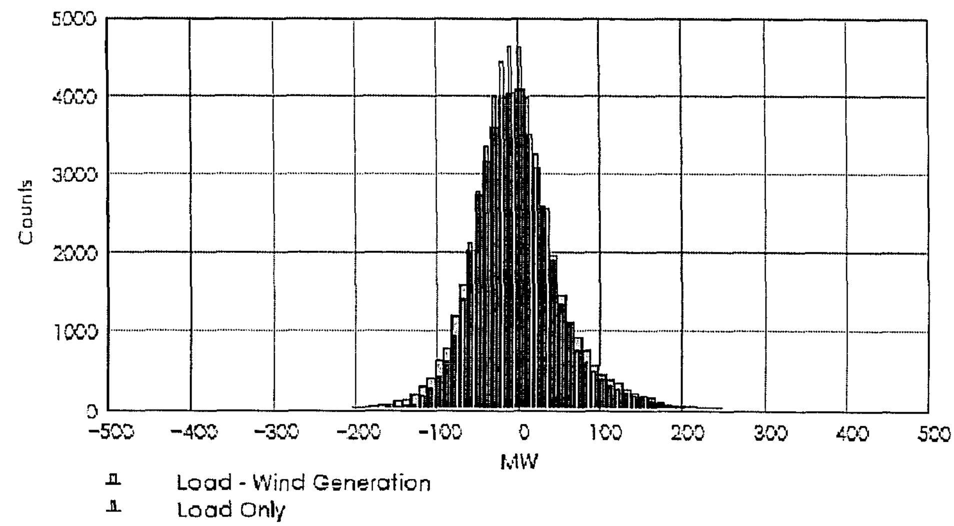


Figure 83: Distribution of ten-minute deviations in system load from hourly trend curve, with (red) and without wind generation (blue).

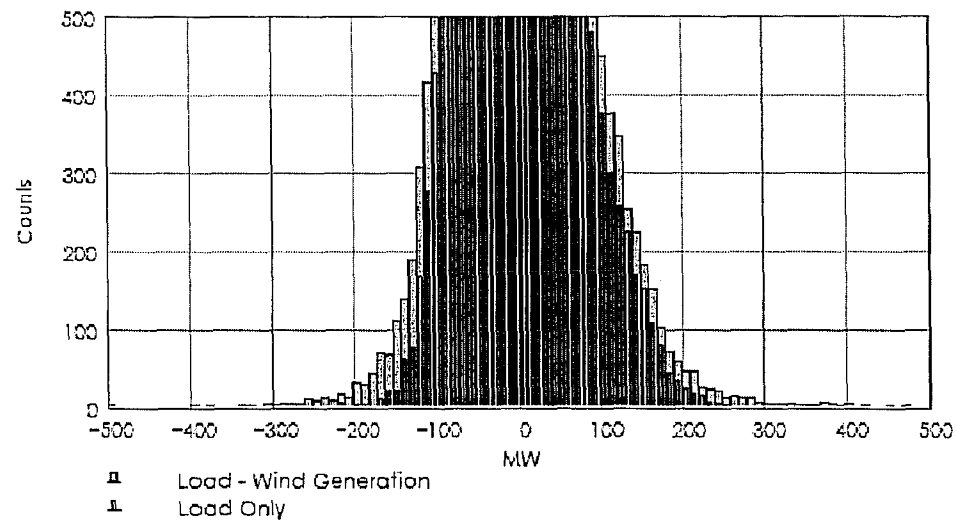


Figure 84: Expanded view of Figure 83.

The numerical results are similar to those described previously that considered the absolute changes on ten-minute increments. The standard deviation of the distribution of deviations from the hourly trend for the load only is 53.4 MW; with wind generation in the control area, the standard deviation increases to 64 MW.

In the earlier study, results from simulations of a limited number of "typical" hours along with several simplifying assumptions were extrapolated to annual projections. A cost impact of $0.41/MWH was assigned to wind generation due to the variability at a time resolution of five minutes. However, one of the major simplifications was that only the wind generation exhibited significant variability from a smooth hourly trend, so that all costs from the intra-hourly simulations beyond those calculated at the hour level could be attributed to wind generation.

The data analyses from the preceding pages paint a somewhat different picture. The system load does vary significantly about a smoother hourly trend curve, and may also vary substantially from one ten-minute interval to the next. With this as the backdrop, it was shown that the addition of wind generation to the control area would have only slight impacts on the intra-hour variability of the net control area demand. It appears that the corresponding changes in wind generation and those in the system load are uncorrelated, which substantially reduces the overall effect of the variations in wind generation within the hour.

In quantitative terms, for the system load alone, just over 90% of the ten-minute variations from the hourly trend value are less than 160 MW. With wind generation, that percentage drops to 86%, or stated another way, 90% of the ten-minute variations from the hourly trend value with wind generation in the control area are less than 180 MW.

The original project plan called for simulations to be used for quantifying the energy cost impacts at the sub-hourly level. This was the approach taken in the earlier study of the Xcel system, and thought during preparation of the proposal to be the most direct method for this assessment. In light of the results of the intra-hourly data analysis, it was determined that detailed chronological simulations would be of very limited value for determining any incremental cost impacts for intra-hourly load following. With a very slight effect on the characteristics of the intra-hourly control area demand characteristic as evidenced by the approximately 10 MW change in the standard deviations, calculated effects on production cost would likely be in the "noise" of any deterministic simulations.

Based on the analysis here, it is concluded that the $0.41/MWH of wind generation arrived at in the previous study was artificially high since the load was assumed to vary smoothly during the hour. Also, the statistical results presented here support the conclusion that the increase in production on an intra-hourly basis due to the wind generation considered here would be negligible.

The results do show, however, that wind generation may have some influence on control performance as the number of large deviations from one interval to the next or from the longer-term trend of the net control area demand are significantly increased. This aspect is analyzed in the next section.

Load Following Reserve Impacts

Maintaining control performance requires an adequate and available inventory of generation that can be loaded or unloaded quickly. Inadequate load following reserves will result in unscheduled interchanges with other control areas that may be in violation of acceptable limits, leading to a degradation of control performance. The period over which these unscheduled flows and the relevant performance standard, CPS2, are tallied is ten minutes. For each ten minute period of the hour (beginning on the hour), the control area ACE (area control error) is checked against a specified maximum limit; periods where ACE exceeds the limits are counted as violations. There are approximately 4320 ten minute periods each month and 52,560 per year.

The "scoring" period for CPS2 is on a monthly basis. To maintain the required performance level of 90% for CPS2, a control area can have no more than, on average, 14.4 ACE violations per day.

Figure 85 shows a further expanded view of Figure 80 which shows the ten-minute control area load changes with and without wind generation. For evaluation of load following reserve impacts and possible effects on control performance, the tails of the distribution are of most interest. It was earlier shown that for a very large percentage of all of the ten minute periods over the one year of sample data, wind generation has very little impact on the magnitude of these changes. At the extremes of the distributions, however, the influence is more apparent.

Note that the distribution is skewed toward positive changes. These would result from sudden decreases in wind generation, which appears as an increase in net control area load. While there are a few instances in the sample where aggregate wind generation suddenly increases, they are far outweighed by the sudden declines.

While not significant from an energy or production cost perspective, the events at the extremes of the distribution could affect control performance, thereby leading to some financial consequence. To assess whether this would be the case for the present scenario, increases in the occurrences of control area demand change of a given magnitude can be "counted". Table 26 shows the number of occurrences over the sample year of data where the net control area load (load minus wind generation) changed more than a given amount (up or down) in one ten minute period.

The impact of the ten minute changes in wind generation can be inferred from the table by considering the present policy for load following reserves and current control performance in terms of CPS2.

To meet the CPS2 for the load alone, the ability to ramp up or down at more than 100 MW per ten minute period (or 10 MW per minute) would be necessary, since the number of changes in the annual data set (5782) is greater than the maximum allowable number of violations over the year (5256), assuming that the changes are evenly distributed across each month (since CPS2 is a pass/fail on a monthly basis). At 12 MW per minute, the control area would be in compliance with CPS2 compliance, even with wind generation. CPS2 performance would be 2% lower (92% vs. 94%).

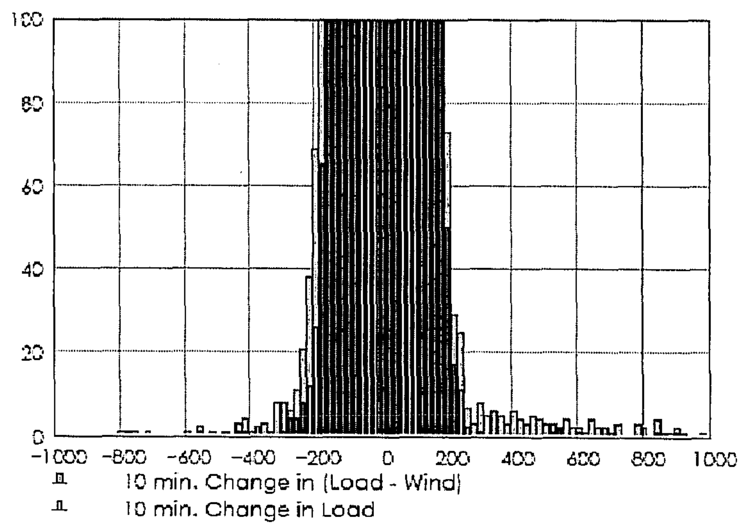


Figure 85: Ten-minute system load changes with (red) and without (blue) wind generation.

Table 26: Extreme System Load Changes – with and without Wind over One Year of Data (~50 K samples)

	# of Occurrences		
10 min. Change	System Load	System Load with Wind	Difference
greater than +/- 100 MW	5782	7153	1371
greater than +/- 120 MW	3121	4148	1027
greater than +/- 140 MW	1571	2284	713
greater than +/- 160 MW	730	1246	516
greater than +/- 200 MW	165	423	258
greater than +/- 400 MW	26	92	66
greater than +/- 600 MW	18	44	26

With a ramping capability of 140 MW per ten minute period, CPS2 performance would be comfortably above the minimum requirement with or without wind generation. Or, from another perspective, if the current CPS2 performance is 94%, maintaining that performance level with the addition of 1500 MW of wind generation would require somewhere between 1 and 2 MW/minute of additional load following capability.

While the addition of wind generation substantially increases the number of larger magnitude deviations (i.e. last three rows of the table), the impact on control performance is small due to the relatively small total number of events. The synthesized wind generation data set does predict, however, that large changes in wind generation do occur even for the geographically diverse scenario considered in this study.

Conclusions – Intra-hourly Impact

Based on analysis of an entire year of ten-minute data, 1500 MW of wind generation in the Xcel control area would have only minor impacts on the volatility of the net control area demand from one ten minute interval to the next. There is also little effect on the deviation of the control area demand from a trend curve representing the longer term (hourly or more) transition through the daily load pattern. As a result, the "energy impacts" inside the hour are assumed to be negligible.

This conclusion conflicts to a degree with those from the earlier study of the Xcel system. In that study, however, the variation of the load within the hour was neglected, with all of the fast ramping of load following resources over and above tracking a smooth progression of the demand from hour-to-hour attributed to wind generation. The data analysis presented here shows that the load variation within the hour is quite significant relative to that expected for wind generation. The variations from the wind generation and the load are also uncorrelated, so there is an overall smoothing effect when considering the entire data set.

Wind generation will slightly increase the requirement for load following resources with fast ramping capability. The number of large deviations from one ten-minute interval to the next is substantially increased by wind generation, such that maintaining control performance would require that additional load following resources be committed to this function. The additional capacity of this incremental load following reserve is somewhat difficult to quantify, since the analysis couches it in terms of fast ramping capability rather than gross capacity. The additional requirement appears to be on the order of 1-2 MW per minute.

Task 4 - Summary and Conclusions

The analysis conducted in this task indicates that the costs of integrating 1500 MW of wind generation into the Xcel control area in 2010 are no higher than $4.60/MWH of wind generation, and are dominated by costs incurred by Xcel to accommodate the significant variability of wind generation and the wind generation forecast errors for the day-ahead time frame.

The total costs include about **$0.23/MWH** as the opportunity cost associated with an 8 MW increase in the regulation requirement, and **$4.37/MWH** of wind generation attributable to unit commitment and scheduling costs. The increase in production cost due to load following within the hour was determined by a statistical analysis of the data to be negligible. The intra-hour analysis also showed that an incremental increase in fast ramping capability of 1-2 MW/minute would be necessary to maintain control performance at present levels. This specific impact was not monetized.

The analytical approach for assessing costs at the hourly level in this study compares the actual delivery of wind energy to a reference case where the same daily quantity of wind energy is delivered as a flat block. In addition to costs associated with variability and uncertainty, the total integration cost then will contain a component related to the differential time value of the energy delivered. If more wind energy is actually delivered "off-peak" relative to the reference case, when marginal costs are lower, this differential value will show up in the integration cost. The total integration cost calculated by this method is still a meaningful and useful value, but care must be taken not to ascribe all of the integration cost to uncertainty and variability of wind generation output.

Wind generation also results in a much larger ramping requirement from hour to hour. The costs associated with this impact are captured by the hourly analysis, as the unit commitment and schedule must accommodate any large and sudden changes in net control area demand in either the forecast optimization case, or in the simulation with actual wind generation. In the optimization case that utilizes wind generation forecast data, generating resources must be committed and deployed to follow control area demand while avoiding ramp rate violations. In the simulation cases with actual wind generation, changes due to wind generation that cannot be accommodated result in "unserved energy" in the parlance of the unit commitment software, which really means that it must be met through same-day or more probably next-hour purchases.

Some specific conclusions and observations include:

1. While the penetration of wind generation in this study is low with respect to the projected system peak load, there are many hours over the course of the year where wind generation is actually serving 20 to 30% (or more) of the system load. A combination of good plans, the right resource mix, and attractive options for dealing with errors in wind generation forecasts are important for substantially reducing cost impacts.

2. That said, the cost impacts calculated here are likely to be somewhat overstated since little in the way of new strategies or changes to practices for short-term planning and scheduling were included in the assumptions, and since the hour-ahead adjustments in the study are made at a price closer to the marginal cost of internal resources than those in a liquid wholesale energy market.

3. The incremental regulation requirement and associated cost for accommodating 1500 MW of wind generation, while calculable, is quite modest. The projected effect of geographic diversity together with the random and uncorrelated nature of the wind

generation fluctuations in the regulating time frame, as shown by the statistical analysis, have a dramatic impact on this aspect of wind generation.

4. Large penetrations of wind generation can impact the hourly ramping requirements in almost all hours of the day. On the hourly level, this results in deployment of more resources to follow the forecast and actual ramps in the net system load, thereby increasing production costs.

5. Wind generation integration costs are sensitive to the deployment of units, which is also a function of the forecast system load. The results seem to indicate that these costs can be high over a period when expensive resources are required to compensate for the hourly variability, even when the total wind generation for the period might be low.

6. For the study year of 2010, the cost of integrating 1500 MW of wind generation into the Xcel-NSP control area could be as high as $4.60/MWH of wind energy where the hour-by-hour forecast of wind for 16 to 40 hours ahead has a mean absolute error of 15% or less. The total integration cost is dominated by the integration cost at the hourly level, and assumes no significant changes to present strategies and practices for short-term unit commitment and scheduling.

7. The MISO market cases demonstrate that the introduction of flexible market transactions to assist with balancing wind generation in both the day-ahead scheduling process and the day one hour ahead has a dramatic positive impact on the integration costs at the hourly level. For example, in August the hourly cost was reduced by two thirds.

Results of the hourly analysis are considered to be quite conservative , i.e. they are on the high end of the range of results that could be generated by varying the assumptions. While the methodology is relatively robust and thought by the researchers to be straightforward and consistent with industry practice, a number of assumptions were made to facilitate analysis of a large set of sample days - two years of days unique in peak load, load pattern, actual and forecast wind generation. The input data for the hourly analysis was developed in such a way that any correlations between Xcel control area load and the wind resource in the upper Midwest are actually embedded in the datasets.

Much of the conservatism in the hourly analysis stems from the simplification of many decisions that would be made by knowledgeable schedulers, traders, and system operators to reduce system costs and/or increase profits. This leads to the use of resources which are under the control of the unit commitment program to accommodate the variability of wind generation and the day-ahead wind generation forecast errors. In months with higher electric demand, these resources can be relatively expensive.

Energy purchases and sales are a potential alternative to internal resources. In the hourly analysis, these transactions were fixed, not allowing for the day-ahead flexibility that might currently exist for judicious use of inexpensive energy to offset the changes in wind generation. Optimizing these transactions day by day would have prevented evaluation of the statistically significant data set of load and wind generation, and would have been to difficult to define objectively.

Given the likely sources of the integration cost at the hourly level, it is apparent that a better strategy for purchase and sale transactions scheduled even day-ahead would reduce integration costs at the hourly level. This leads naturally to considering how wholesale energy markets would affect wind integration costs.

The planning studies conducted by MISO show that wholesale energy is relatively inexpensive in the upper Midwestern portion of their footprint. Transmission constraints do come into play on a daily and seasonal basis, but interchange limits for most of Minnesota are reasonably high relative to the amount of wind generation considered in this study. The ability to use the wholesale energy market as a balancing resource for wind generation on the hourly level has significant potential for reducing the integration costs identified here.

Wholesale energy markets potentially have advantages over bi-lateral transactions as considered simplistically in this study. In day-ahead planning, for example, it would be possible to schedule variable hourly transactions consistent with the forecast variability of the wind generation. Currently, day-ahead bi-lateral transactions are practically limited to profiles that are either flat or shapeable to only a limited extent. Hour-ahead purchases and sales at market prices would provide increased flexibility for dealing with significant wind generation forecast errors, displacing the more expensive units or energy fire sales that sometimes result when relying on internal resources.

Project Retrospective and Recommendations

Observations

Value of Chronological Wind and Load Data for Analysis

The numerical meteorological simulation was the basis for all of the technical analysis in this study. Compared with previous efforts to assess operating impacts that the project team either participated in or is very familiar with, this chronological wind generation data has advantages and provided for improvements to the analytical methods used to assess integration costs:

- The numerical modeling approach can properly capture the important relationships between geographically diverse wind plants. These relationships are critical to avoid either under- or over-estimating the effects of wind generation on control area operations. Other approaches must rely on approximations, assumptions, or extension of limited amounts of data, and therefore cannot capture the true correlation between plants that are driven by the same meteorology but at different times and potentially in different ways due to geographic location.
- The wind generation model can be easily validated and fine-tuned for specific locations when sufficient measurement data from operating wind plants is available.
- The modeling technique employed by WindLogics automatically embeds any correlation between wind generation and system load when the analytical techniques use system load records from the years for which the numerical simulations were run. These correlations would arise from the dependence of the system load on the same meteorology that drives the wind resource.
- With further applications of the technique, validation may become less critical, allowing it to be used in areas where no wind generation currently operates.
- The incremental cost to archive additional proxy "tower" locations is small. Data for all of the prospective development sites in a control area could be generated in a single run. A variety of development scenarios could be constructed from this single data set.
- The nature and quality of the data from the numerical simulations has application to not only the investigation of operating impacts as in this study, but also in the assessment of transmission issues and as baseline data for evaluating strategies and operator response to significant wind generation events, i.e. those where the total wind generation might change by a large amount in a relatively short period of time.

Variability and Forecast Error

In the hourly analysis, it was originally thought that the production cost from the intermediate case, where wind generation forecast rather than the "actual" data was used to develop a unit commitment and schedule, could be used to assess the cost of wind generation variability, and that the difference between this cost and the production cost from the "actual" case was due to forecast error.

The three sets of cases were analyzed with this hypothesis in mind. It was found that such a tidy differentiation of costs does not seem to exist in the case results, as there are certain months where the forecast production cost is actually higher than the actual cost. Somewhat surprisingly, those instances correspond to cases where the total wind generation forecast for the month was smaller than what was actually delivered.

Figure 86 shows the forecast error in MWH plotted against the difference in production cost between the "actual" and "forecast" cases. When the actual wind generation is larger than the forecast wind generation, the production cost for the forecast case tends to be higher than for that using the actual wind generation data.

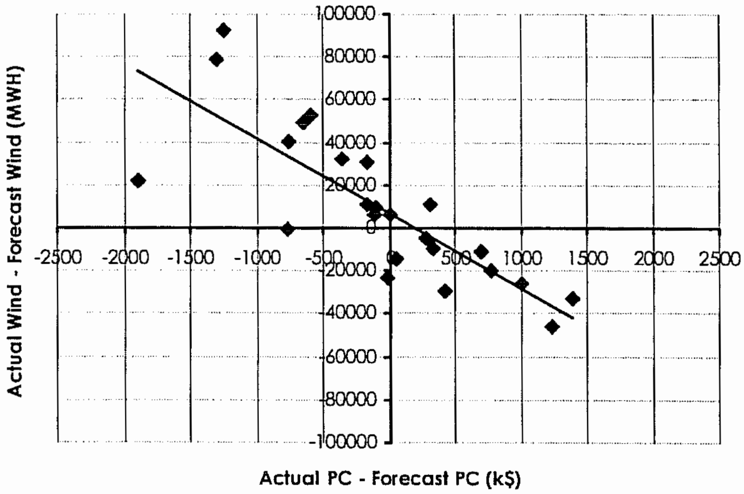


Figure 86: Empirical relationship between monthly wind energy forecast error and production cost difference between actual and forecast cases.

In Figure 87, production cost differences between the actual and forecast cases and the actual and base cases are plotted as a function of monthly wind energy forecast error. Non-linear trend lines for the data are also shown.

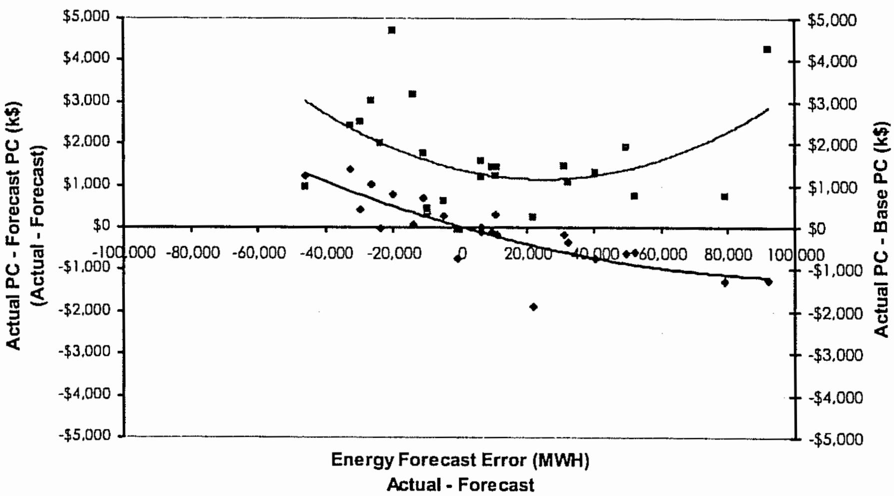


Figure 87: Empirical relationship between monthly energy forecast error and a) production cost difference between actual and forecast case (black); and b) actual and base case (magenta).

It is difficult to draw any definitive conclusions from the previous plots, other than that the "Forecast" case does not conveniently divide the cost of the wind variability from the predictability. They do, however, suggest some tantalizing relationships between forecast error and integration cost that must be left for further research efforts.

Methodology and Tools

With the meteorological simulation data as the basis for the wind generation model, and load data for the corresponding years and hours of the simulation, the analytical methodology can be structured to closely mimic the operating practice and procedures for any control area. In essence, the analysis really becomes one of "try it and see what happens", since nearly all of the actual day-to-day decisions made in the generation commitment and scheduling process can be simulated.

The disadvantage of this approach is that it is data- intensive, and computer simulation time for the optimization cases is significant. In addition, some trade-offs between accurate modeling of all operating practices and time horizon for the study may be necessary, since introducing more detail in the case setup and assumptions, as would actually be the case as the schedulers are looking out to the next day or days, makes running the cases necessary for annualizing costs a tall order in terms of human resource. The results of such an exercise, however, would be of extremely high quality and very meaningful in the specific context of the wind generation scenario considered and the control area being studied.

Given the complexity of the problem, however, there is no alternate way at this time to even estimate these impacts from a cost-based perspective. The problem is not as daunting in regions with a range of energy and ancillary service markets, if, of course, it can be assumed that the additional wind generation would not influence prices in any of the relevant markets.

While the Areva dispatch training simulator was found not to be necessary for completing the scope of this study, the software modifications made in anticipation of its use in Task 4 along with the effort expended to develop the simplified model for the Xcel control area do show the significant potential value of such a tool for future investigations. Based on the experience garnered from this study, it is concluded that such a platform combined with the chronological wind generation data is the preferred environment for future studies. It would provide the ability to capture all of the system impacts - both technical and economic - in an integrated fashion. This will be especially important where it is not possible to completely decouple or categorize the effects on the operation of other generators in the control area. Inclusion of the transmission network would allow investigation of other system impacts - such as voltage regulation, which could impact the commitment and scheduling of generators - along with the impacts considered here.

Further development and application of the dispatch training simulator as an analytical tool would eventually provide a path for the simulator to be used for its original intended application: Training power system operators. The elements combined for the analysis in Task 4 of this study - the wind resource characterization and wind generation model development, the wind generation forecast data, and the hourly analysis - could form the basis for providing operators with experience in dealing with the additional challenges related to wind generation well before it actually becomes a reality in the control area.

Recommendations for Further Investigation

Because the assessment of economic and technical impacts of large amounts of wind generation on power system operation is a relatively new area of study, an intensive investigation like the one reported on here invariably generates new sets of questions and topics for further exploration. Other questions have been identified in the course of other studies, but no opportunities have yet arisen to for them to be adequately considered. The next paragraphs attempt to identify those questions and topics relevant to the data, methods, and results from this study in the hope that they can contribute to the formulation of future research efforts.

As mentioned previously, the wind generation data set used here is unique. The scope and schedule for this study did not allow for a complete exploration of the wind data or the algorithms used to create the chronological wind generation model. Recommendations for such analysis include:

- Quantification of correlations between wind generation and the system load data. For instance, wind generation has a larger probability of being low on summer afternoons. Is there any correlation between load and wind that might be attributable to meteorology, i.e. peak loads on hot, muggy, and still days, and higher winds in the wake of a frontal passage that would likely reduce daily peak load significantly
- Refinement of the algorithms for translating wind speed data at a proxy tower location to wind generation, more accurately accounting for array and electrical losses.
- Further validation of the wind generation model, especially at higher time resolutions.
- Assessment of the costs and potential benefits of alternate temporal and spatial resolutions - e.g. 5 min. at 2 km.
- What are the limitations of the meteorological simulations in terms of validity at various spatial and temporal levels - e.g. could the numerical techniques be applied on a turbine-by-turbine basis for an individual plant?
- Analytical characterizations of the correlations between individual wind plant output for different seasons, wind directions, etc.
- Parametric investigation of the sensitivity of integration costs to market structure and prices.

The ELCC analysis using the GE MARS program was based primarily on previous work by Milligan at NREL. In discussions with Milligan through the course of work in this study, a number of areas for further investigation were identified:

- How can or should temporal and seasonal patterns in wind generation best be captured in the chronological reliability calculation using Monte Carlo techniques and state transition matrix representations for generating resources?
- How does neglecting unit commitment in the calculation de-value the reliability contribution of wind plants? In GE MARS, units that may be off-line due to commitment decisions are assumed to be available, thereby increasing their capacity value relative to wind generation, which would have no such constraints.
- What modifications might be made to a tool like GE MARS to improve its applicability to reliability assessments including unique resources like wind generation?
- Given that an ELCC method has been recommended as an improvement to capacity accreditation methods like that used by MAPP, what type and how much data would be necessary to construct the wind generation models?

Wind generation forecast time-series were essential for the methods employed in this study. Additional validation of the forecast errors assumed here would be beneficial. For studies of this type going forward, other questions to be addressed include:

- How would forecast errors for a single wind plant compare to those from a wide-area wind generation forecasting system, where a third-party is charged with developing a wind production forecast for an entire control area? Would the results for the aggregate forecast be expected to be smaller, due to compensating errors in individual plant forecasts, or of the same relative magnitude?
- How might confidence levels be incorporated into wind generation forecasts?

The integration costs identified here are driven by commitment and dispatch decisions at the hourly level. There are many variations of the assumptions and approach used here that could shed further light on the specific drivers of these integration costs as well as on opportunities for reducing them. On this list are:

- The relationship between integration cost and wind generation penetration level for a specific system.
- The sources of significant non-linearities in the integration cost vs. penetration curve
- The relationship between wind generation forecast error and integration cost.
- Alternate methods for incorporating wind generation forecasts and associated confidence intervals into the unit commitment process – e.g. a modification of the hour-by-hour next-day forecast using a rolling average or windowing technique, intentional under- or -over forecasting, etc.
- Alternate algorithms for solving the unit commitment problem in the face of increased uncertainty due to wind generation – e.g. stochastic unit commitment.
- Improved modeling of day-ahead unit commitment decisions and transaction scheduling, which could be accomplished by changing assumptions and running simulations one day, rather than one month, at a time.
- Formal treatment of load forecast errors, which could be done with some built-in features of the unit commitment program.
- Higher-fidelity treatment and simulation of wholesale energy markets, including seasonal and daily price curves based on historical data.
- Additional evaluation of the "base" case, which establishes the reference production costs from which the wind generation integration cost is computed.
- Assessment of very high penetration levels to determine if there is a point or region (for a given system) beyond which additional wind generation could not be technically accommodated by the system, and to shed light on the relationship between penetration level and integration cost..
- Assessment of the effect of resource mix on integration costs.

Finally, the wind generation model data developed for this study coupled with high-resolution, high-fidelity simulation platform such as the Dispatch Training Simulator (with the software modifications made during this study) would allow for a completely comprehensive investigation of all the operational questions related to large amounts of wind generation. With the transmission network model included, the uses of the platform would encompass the entire universe of operational questions related to wind generation.

References

[1] Utility Wind Interest Group (UWIG): "Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning" May, 2003 www.uwig.org

[2] Hirst, E. and Kirby, B. "Separating and Measuring the Regulation and Load Following Ancillary Services" November, 1998 (available at www.EHirst.com)

[3] Hirst, E. and Kirby, B. "What is the Correct Time-Averaging Period for the Regulation Ancillary Service?" April, 2000 (available at www.EHirst.com)

[4] Piwko, R., et.al. "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations - Report on Phase 1: Preliminary Overall Reliability Assessment" for the New York State Energy Research and Development Authority (NYSERDA), published February, 2004 (available at www.nyserda.org/energyresources/wind.html)

[5] NREL/CP-500-26722: "Short-term Power fluctuation of Wind Turbines: Analyzing data from the German 250 MW Measurement Program from the Ancillary Services Viewpoint"

[6] Parsons, B.P, et. al. "Grid Impacts of Wind Power; A Summary of Recent Studies in the United States" presented at the 2003 European Wind Energy Conference, Madrid, Spain, June 2003.

[7] Milligan, M.R. "A Sliding Window Technique for Calculating System LOLP Contributions of Wind Power Plants" presented at the 2001 AWEA Windpower Conference, Washington, DC, June 4-7, 2001. NREL/CP-500-30363

[8] Milligan, M.R., et. al. "An Enumerative Technique for Modeling Wind Power Variations in Production Costing" presented at the International Conference on Probabilistic Methods Applied to Power Systems, Vancouver, BC, Canada, September 21-25, 1997. NREL/CP-440-22868

[9] Milligan, M.R., et. al. "An Enumerated Probabilistic Simulation Technique and Case Study: Integrating Wind Power into Utility Production Cost Models" presented at the IEEE Power Engineering Society Summer Meeting, Denver, CO, July 29 - August 1, 1996. NREL/TP-440-21530

[10] Milligan, M.R., "Measuring Wind Plant Capacity Value" NREL White Paper

[11] Milligan, M. "Windpower and System Operation in the Hourly Time Domain" presented at the 2003 AWEA Windpower Conference, May 18-21, 2003, Austin, TX. NREL/CP-500-33955

[12] Hirst, Eric, "Interaction of Wind Farms with Bulk Power Operations and Markets" prepared for the Project for Sustainable FERC Energy Policy, September 2001

[13] Milligan, M.R. "A Chronological Reliability Model to Assess Operating Reserve Allocation to Wind Power Plants" presented at the 2001 European Wind Energy Conference, July 2-6, 2001, Copenhagen, Denmark. NREL/CP-500-30490

[14] Milligan, M.R. "A Chronological Reliability Model Incorporating Wind Forecasts to Assess Wind Plant Reserve Allocation" presented at 2002 AWEA Windpower Conference, June 3-5, 2002, Portland, OR. NREL/CP-500-32210

[15] Karady, George G., et. al., "Economic Impact Analysis of Load Forecasting", IEEE Transactions on Power Systems, Volume 12, No. 3, August, 1997. pp. 1388 - 1392.

[16] L.L. Garver, Effective Load Carrying Capability of Generating Units IEEE Transactions on Power Apparatus and Systems VOL PAS-85, No 8, pp 910-919 August, 1966

Exhibit No. EDK-8

Term sheet for Java Wind Project Power Purchase Agreement

Seller: Superior Renewable Energy, LLC ("**Seller**").

Buyer: Montana-Dakota Utilities Co. ("**Buyer**").

Power Purchase Agreement: (a) Seller and Buyer shall enter into a Master Power Purchase And Sale Agreement utilizing the form of the EEI Master Agreement ("**Master Agreement**") attached hereto and a Confirmation Letter ("**Confirmation**") thereunder, which Confirmation shall set forth the terms and conditions of the power purchase transaction between Buyer and Seller.

(b) Under this Confirmation, (i) Seller shall design, construct and operate the Java Wind Project, a wind generating project located in Walworth County, South Dakota (the "**Project**"), with a nameplate capacity rating of 30.6 MW ("**Nameplate Rating**"), (ii) Seller shall sell all the electric capacity, electric energy, and renewable energy credits (and all other environmental benefits attributed to wind-generated electricity) produced by the Project to Buyer, (iii) Buyer shall accept delivery from Seller at the Delivery Point of all electric energy produced by the Project up to a maximum quantity of 30.6 MWh per hour of electric energy, and (iv) Buyer shall pay to Seller the Energy Payments and Capacity Payments, less any fess or other costs, as set forth herein, all as more fully described in this Confirmation.

(c) Buyer shall have no obligation to purchase any quantity of energy from the Project in excess of 30.6 MWh per hour. Seller may not procure energy from a third party or another generation facility for sale and delivery to Buyer under this Confirmation.

Term: (a) The term of this Confirmation shall become effective on the date of execution, and shall continue in effect for a term of 10 years running from the commercial operation date (the "**COD**") of the Project until the 10th anniversary of the first day of the month following the COD of the Project, unless earlier terminated in accordance with the terms of the Confirmation (the "**Term**").

(b) The COD of the Project shall occur when wind-turbine generators with an aggregate nameplate capacity rating of no less than 30.6 MW have been installed, tested and are able to operate continuously, subject to wind resource availability, to generate electric energy for delivery to Buyer at the Delivery Point.

(c) If the COD of the Project does not occur on or before 1 June 2006, the Contract Prices will be revised by the Buyer to reflect the then-current Avoided Costs.

Termination Prior to the COD:

(a) Buyer's obligations under this Confirmation are contingent on the Seller at all times having a valid status as a Qualifying Facility ("**QF**") under PURPA. Should the Seller cease to be a QF at any time prior to the COD, Buyer may terminate this Confirmation without any further obligation under the Master Agreement and with no liability to Seller.

(b) Buyer's obligations under this Confirmation shall be contingent on (i) Buyer receiving approval of this Confirmation by the SDPUC, and (ii) Buyer's ability to recover in its retail rates all costs incurred under this Confirmation, from the South Dakota Public Utilities Commission, the North Dakota Public Service Commission, and the Montana Public Service Commission. If all such approvals have not been obtained on or before12 months after execution of this Confirmation, then Buyer may terminate this Confirmation without any further obligations under the Master Agreement and with no liability to Seller, or at the option of the Seller, the Buyer's obligations shall be limited to the extent of cost recovery approvals.

(c) If the COD of the Project does not occur on or before the later of 1 June 2006 or 6 months after the originally scheduled COD, then Buyer may terminate this Confirmation without any further obligations under the Master Agreement and with no liability to Seller.

Termination after COD:

(a) Buyer's obligations under this Confirmation are contingent on the Seller at all times having a valid status as a QF under PURPA. Should the Seller cease to be a QF at any time after the COD, Buyer may terminate this Confirmation without any further obligation under the Master Agreement and with no liability to Seller.

(b) Buyer's obligations under this Confirmation shall be contingent on Buyer's ability to recover in its retail rates all costs incurred under this Confirmation, from the South Dakota Public Utilities Commission, the North Dakota Public Service Commission, and the Montana Public Service Commission. If Buyer is not permitted to recover all costs incurred under this Confirmation at any time after COD, then Buyer may terminate this Confirmation without any further obligations under the Master Agreement and with no liability to Seller or at the option of the Seller, the Buyer's obligations shall be limited to the extent of the cost recovery approvals.

Wind Integration Adjustment

Payments to the Seller will be reduced by an amount of $4.60 per MWh, escalated from 1 Jan 2005 in each year by an amount equal to the GNP Implicit Price Deflator published by the U.S. Department of Commerce Bureau of Labor Statistics, for each MWh delivered during the Term of this Confirmation to compensate the Buyer for integrating and scheduling the intermittent output of the Project.

This Wind Integration Adjustment will be deducted from total Energy and Capacity Payments due to the Seller in each monthly statement. In any month where the amount of the Wind Integration Adjustment exceeds the total Energy and Capacity Payments prior to deducting the Wind Integration Adjustment, the monthly payment to Seller will be zero and any un-paid Wind Integration Adjustment will be carried over to the next month or months.

Pricing Periods

For Contract Payments, three periods are defined as:

(a) Period 1 – from COD to 15 June 2007

(b) Period 2 – from the end of Period 1 until the beginning of Period 3

(c) Period 3 – from 15 June 2011 until the end of the term of this Confirmation

Contract Payments:

(a) Stipulated Avoided Energy Payment. For electric energy generated by the Project and delivered to Buyer at the Delivery Point during the Term of this Confirmation prior to the operational date of the Midwest Independent System Operation Day 2 electricity market, Buyer shall pay Seller an Energy Payment that is calculated as the product of (i) the stipulated avoided energy prices included in Schedule A (with a Summer and Winter on-peak and off-peak price for each year of the term of this Confirmation), (ii) the energy production of the Project in MWh in each of the periods (ie, Summer and Winter on-peak and off-peak) as metered at the Delivery Point, and (iii) the Transmission Loss Factor.

(b) Market-based Avoided Energy Payment during Period 1 and Period 2. For electric energy generated by the Project and delivered to Buyer at the Delivery Point during the Period 1 and Period 2 and after the operational date of the Midwest Independent System Operation Day 2 electricity market, Buyer shall pay Seller an Energy Payment that is calculated as the product of the load-weighted average hourly locational marginal MISO spot market price for the Montana-Dakota system and the energy production of the Project in MWh.

(c) Market-based Avoided Energy Payment during Period 3. For electric energy generated in each hour by the Project and delivered to Buyer at the Delivery Point during Period 3 and after the operational date of the Midwest Independent System Operation Day 2 electricity market, Buyer shall pay Seller an Energy Payment that is calculated as:

(i) The hourly variable cost of energy from the avoided base load unit as set forth in Schedule B times the energy production of the Facility in MWh up to a maximum of 7 MWh per hour of output in each hour (or the actual MAPP accredited amount used to determine avoided capacity payments, if different from the initial Superior estimate of 7 MW); and

(ii) The load-weighted average hourly locational marginal MISO spot market price for the Montana-Dakota system times the energy production of the Project in MWh for all energy production in excess of 7 MWh per hour of output in each hour

(d) Avoided Capacity Payment: From COD until the Project receives a MAPP monthly accredited capacity, the Seller will pay the Buyer each month an amount that is equal to the Monthly Avoided Capacity price in Schedule C times 7 MW in each month. In each year after the Project receives a MAPP monthly accredited capacity amount, the Seller will pay the Buyer each month an amount that is equal to the Monthly Avoided Capacity price in Schedule C times the minimum MAPP accredited monthly capacity in the prior year during Montana-Dakota's summer peak months (ie, June, July, August and September) in the prior year. This means that the Project's Avoided Capacity Payments in each year will be linked to the Project's MAPP accredited capacity set in the prior year; this could result in the Avoided Capacity Payments being either lower or higher than the payments with a stipulated avoided capacity amount of 7 MW.

(e) Refund of Avoided Capacity overpayments: If the minimum actual MAPP accredited monthly capacity for the Project during the summer peak for the first year when such information is available is lower than 7 MW, the Project shall make a refund to Montana-Dakota of an amount equal to the difference between the actual amount and 7 MW times the Monthly Avoided Capacity price in Schedule C for all payments made to that time.

Renewable Energy Credits	No separate payment for renewable energy credits (or any other environmental benefit attributed to wind-generated energy) will be paid by Buyer, but Buyer shall receive all renewable energy or other environmental credits and these credits shall be considered to have been purchased by the Buyer in return for the Energy and Capacity Payments.
Indemnification for Operating Costs:	To the extent that the Buyer is assessed any penalties, fees, or other costs as a result of the Project's operation, the Buyer will have the right to deduct such penalties, fees or other costs from total Energy and Capacity Payments in each monthly statement. In any month where the amount of such penalties, fees or other costs exceeds the total Energy and Capacity Payments AFTER to deducting the Wind Integration Adjustment, the monthly net payment to Seller will be zero and any un-paid penalties, fees or other costs will be carried over to the next month or months.
Interconnection	(a) The Seller is responsible for applying for interconnection and firm

and firm transmission
transmission, and the costs of any studies, application fees, or system upgrade costs shall be the sole responsibility of the Seller.

(b) Notwithstanding any other provision of this Agreement, if the Project has not received firm transmission rights by the COD for the full amount of MAPP accredited capacity for the Java Project, the Buyer will not be obligated to pay any Avoided Capacity Payments to the Seller for the amount of MAPP accredited capacity which firm transmission has not been obtained.

Delivery Point
The Delivery Point shall be the high-side of the transformer at Buyer's [________] substation located at [__________], South Dakota. Other Points of Delivery may be established by mutual agreement of Buyer and Seller. Title to and risk of loss related to electric energy shall transfer from Seller to Buyer upon delivery at the Delivery Point, and each party shall be responsible for all activities on its side of the Delivery Point, in accordance with more detailed provisions to be set forth in the Confirmation.

Transmission loss factor
The output of the Project, as metered at the Delivery Point, shall be adjusted by a Transmission Loss Factor **("TLF")** to reflect the expected losses that Montana-Dakota will incur as a result of these deliveries. The TLR shall be a percentage that is equal to 1 minus the expected losses (in percent) of the energy delivered by the Project. Montana-Dakota shall update the transmission loss factor as appropriate to reflect changes in the Montana-Dakota system. Montana-Dakota may, at its sole option, use system average transmission loss factors, rather than calculating a TLF that is specific to the Project. Schedule D sets out the initial TLF.

No Net Deliveries
The Project shall deliver all output of the wind turbines to the Delivery Point for sale to Buyer. If the Project has any need for electricity service (ie, station load) at the Project, this electricity service will be obtained from Montana-Dakota under its normal service tariffs and conditions.

Test Energy
The Project will likely desire to deliver energy to the Buyer at the Delivery Point prior to the COD as a result of initial operation and testing of wind turbines (**"Test Energy")**. The Seller will coordinate and schedule all such deliveries of Test Energy with the Buyer. The Buyer will purchase all Test Energy at a price that is 75% of the Stipulated Avoided Energy prices in 2006.

Curtailment
The Buyer has the right from time to time to curtail (ie, order the reduction in output of the Project) at any time for any reason. The Buyer will give the Seller prior notice of the maximum allowable output of the Project at the Delivery Point (which might be, as the Buyer's discretion zero MW), the start time and date of the curtailment period and the end time and date of the curtailment period (the end time and

date may be indefinite). Notice of curtailment will be by telephone and confirmed in writing. Upon receiving notice of curtailment, the Seller will comply with any Curtailment order immediately. If there is a failure of the Seller to implement any Curtailment order from the Buyer, the Buyer will have the right to disconnect the Project from the Buyer's system.

If Project curtailment is mandated by the transmission system operator as a result of constraints on the transmission system, the need to protect the transmission system, or emergencies, such Curtailment hours will not be counted toward the total annual amount of Curtailment for the purposes of potential reimbursement.

So long as the total annual amount that the Project is Curtailed does not exceed [15] days per year, there shall be no compensation from the Buyer. If the total annual amount of Curtailment exceeds [15] days per year hours, the Buyer will compensate the Seller for such excess curtailment. The Seller will maintain wind data collection devices on the site of the Project that will be used to record the wind speed during any curtailment periods and the Seller will use this wind speed data and corrected wind turbine curves to estimate the energy that would have been produced during the excess curtailment hours. The Seller will provide this estimate of excess curtailment energy to the Buyer, who will calculate the amount of any payments due to the Seller for excess curtailment, with such payments included in a future monthly statement.

Scheduling; Communications; Voltage Stability; Outages; Metering, Etc.:

(a) By 6:00 AM local time on each Business Day preceding each date of delivery, Seller shall provide Buyer an hourly forecast of deliveries for such date of delivery. Seller shall update such forecast anytime information is available indicating a change in the forecasted output of the Project. Seller shall prepare such forecasts and updates by utilizing the best wind speed and direction prediction model or service that is commercially available and utilized by other wind producers or purchasers in the vicinity of the Project, so long as such model or service is available at a commercially reasonable cost. Seller shall determine in good faith which such model or service to utilize after consultation with Buyer. Seller shall not be required to update such forecasts more frequently than once each hour.

(b) On or before the COD, Seller shall install a SCADA (supervisory control and data acquisition) system, subject to Buyer's written consent to such system, to ensure real-time communication of operational data from the Project to Buyer's control desk. Such systems shall include devices that allow the Buyer to remotely disconnect the Project from the power network.

(c) On or before the COD, and at least annually thereafter, Seller shall demonstrate to Buyer's reasonable satisfaction that the Project is able to (i) continue operations during a low voltage condition on Buyer's transmission system, (ii) stabilize voltage levels, and (iii) help Buyer's transmission system stay in balance.

(d) All electric energy delivered by Seller to Buyer shall have a power factor of no less than .95 lagging nor greater than .95 leading.

(e) The Confirmation shall contain provisions setting forth communications procedures between the parties relating to the scheduling of outages, and the notification of unscheduled outages, emergencies and other similar events relating to Seller's and Buyer's facilities. The Confirmation also shall set forth detailed provisions for Buyer's metering of the electrical energy deliveries at the Delivery Point.

Credit Support

Seller shall provide credit support in an amount equal to $__________ as credit support for all Seller's payment obligations under this Confirmation, including payment of any termination amount owed as a result of any termination of this Confirmation due to an Event of Default by Seller. Such credit support may comprise a cash deposit or an irrevocable letter of credit from a commercial bank rated ___ or higher by Standard & Poor's and Moody's.

Default and Remedies:

It shall be an Event of Default if: (i) Seller fails to deliver any energy for a period of 12 months following the COD for any reason other than a Force Majeure or a weather-related condition, in which case Seller is the defaulting party; or (ii) either party fails to make a payment when due hereunder and such payment remains unpaid within five (5) days after notice thereof from the non-defaulting party; or (iii) either party becomes Bankrupt.

Regulatory Approvals:

Buyer's obligations under this Confirmation are subject to Buyer's receipt of authorization to recover the costs of power purchased from Seller in retail rates approved by the SD PUC, the North Dakota PSC, and the Montana PSC. If, at any time during the Term of this Confirmation, the Buyer ceases to have the approval to recover in its retail rates all costs incurred under this Confirmation, from the South Dakota Public Utilities Commission, the North Dakota Public Utilities Commission, and the Montana Public Utilities Commission, the Buyer may terminate this Confirmation without any further obligation under the Master Agreement and with no liability to Seller, or at the option of the Seller, the Buyer's obligations shall be limited to the extent of cost recovery approvals.

Termination for Force Majeure:

If either party fails to perform its obligations hereunder for a period of 18 consecutive months due to a Force Majeure, then either party may terminate this Confirmation without further obligations under the Master Agreement or this Confirmation and without liability to the other party.

Other items

(a) Early termination security – the Avoided Capacity Payments to the Seller are based upon operation of the Project to the end of the term of this Agreement. The Seller will provide appropriate security to the Buyer that is paid to the Buyer in the event that the Project ceases to operate prior to the end of the term of the Agreement which payments shall be equal to the capacity payments the Seller would have otherwise received during the balance of the term of this Agreement. Schedule E contains the security amounts that are required in each year of the Confirmation term.

(b) Assignment – the Seller may not assign the rights under this Agreement without the express written permission of the Buyer

(c) Buy-Out of Project and Agreement – the Seller and the Buyer agree that the Buyer has the right but not the obligation to purchase the Project, including all rights to this Agreement, from the Seller at any time during the term of the Agreement. Schedule F sets forth an amount in each year of the term of this Agreement that is the agreed sale and purchase price for the Project and all rights to this Agreement. Nothing in this provision restricts the Seller and Buyer from negotiating a purchase and sale of the Project and the rights to this Agreement for an amounts that differs from the amounts in Schedule F.

Schedule A — This is a table that has the stipulated avoided energy prices (in $/MWH) for Summer and Winter On-Peak and Off-Peak periods for each year of the Confirmation term. This Schedule A would contain the Stipulated Avoided Energy Cost amounts in Exhibit EDK-5

Schedule B — This is a calculation of the avoided energy price from the avoided base load unit in Period 3. [Query: Should this price change from year to year with coal prices?]

Schedule C — This is a table that contains the stipulated avoided capacity price (in $ per KW per year and $ per KW per month) for each year of the Confirmation term. This Schedule C would contain the Levelized Avoided Capacity Cost amounts in Exhibit EDK-4

Schedule D — This is the Transmission Loss Factor that applies to the Project. This Schedule will also contain the Montana-Dakota process for calculating the TLF and the schedule for updating the TLF calculation.

Schedule E — This is a table that contains the amount of early termination security that the Project must maintain (in $) during each year of the Confirmation term.

Schedule F — This is a table that contains a negotiated buy-out price (in $) for each year of the Confirmation term. The amounts in this Schedule E are to be negotiated and agreed by the Seller and Buyer prior to the execution of this Confirmation.